other surface mining.[19,27] There are 6,300 MTR and surface mining jobs in West Virginia, representing 0.7–0.8% of the state labor force.[2] Coal companies are also employing more people through temporary mining agencies and populations are shifting: between 1995 and 2000 coal-mining West Virginian counties experienced a net loss of 639 people to migration compared with a net migration gain of 422 people in nonmining counties.[19,80]

Combustion

The next stage in the life cycle of coal is combustion to generate energy. Here we focus on coal-fired electricity-generating plants. The by-products of coal combustion include CO_2, methane, particulates and oxides of nitrogen, oxides of sulfur, mercury, and a wide range of carcinogenic chemicals and heavy metals.[20]

Long-range air pollutants and air quality. Data from the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID)[81] and National Emissions Inventory (NEI)[82] demonstrates that coal power is responsible for much of the U.S. power generation-related emissions of $PM_{2.5}$ (51%), NO_x (35%), and SO_2 (85%). Along with primary emissions of the particulates, SO_2 and NO_x contribute to increases in airborne particle concentrations through secondary transformation processes.[20,21,83]

Studies in New England[84] find that, although populations within a 30-mile radius of coal-fired power plants make up a small contribution to aggregate respiratory illness, on a per capita basis, the impacts on those nearby populations are two to five times greater than those living at a distance. Data in Kentucky suggest similar zones of high impact.

The direct health impacts of SO_2 include respiratory illnesses—wheezing and exacerbation of asthma, shortness of breath, nasal congestion, and pulmonary inflammation—plus heart arrhythmias, LBW, and increased risk of infant death.

The nitrogen-containing emissions (from burning all fossil fuels and from agriculture) cause damages through several pathways. When combined with volatile organic compounds, they can form not only particulates but also ground-level ozone (photochemical smog). Ozone itself is corrosive to the lining of the lungs, and also acts as a local heat-trapping gas.

Epidemiology of air pollution. Estimates of nonfatal health endpoints from coal-related pollutants vary, but are substantial—including 2,800 from lung cancer, 38,200 nonfatal heart attacks and tens of thousands of emergency room visits, hospitalizations, and lost work days.[85] A review[83] of the epidemiology of airborne particles documented that exposure to $PM_{2.5}$ is linked with all-cause premature mortality, cardiovascular and cardiopulmonary mortality, as well as respiratory illnesses, hospitalizations, respiratory and lung function symptoms, and school absences. Those exposed to a higher concentration of $PM_{2.5}$ were at higher risk.[86] Particulates are a cause of lung and heart disease, and premature death,[83] and increase hospitalization costs. Diabetes mellitus enhances the health impacts of particulates[87] and has been implicated in sudden infant death syndrome.[88] Pollution from two older coal-fired power plants in the U.S. Northeast was linked to approximately 70 deaths, tens of thousands of asthma attacks, and hundreds of thousands of episodes of upper respiratory illnesses annually.[89]

A reanalysis of a large U.S. cohort study on the health effects of air pollution, the Harvard Six Cities Study, by Schwartz *et al.*[90] used year-to-year changes in $PM_{2.5}$ concentrations instead of assigning each city a constant $PM_{2.5}$ concentration. To construct one composite estimate for mortality risk from $PM_{2.5}$, the reanalysis also allowed for yearly lags in mortality effects from exposure to $PM_{2.5}$, and revealed that the relative risk of mortality increases by 1.1 per 10 $\mu g/m^3$ increase in $PM_{2.5}$ the year of death, but just 1.025 per 10 $\mu g/m^3$ increase in $PM_{2.5}$ the year before death. This indicates that most of the increase in risk of mortality from $PM_{2.5}$ exposure occurs in the same year as the exposure. The reanalysis also found little evidence for a threshold, meaning that there may be no "safe" levels of $PM_{2.5}$ and that all levels of $PM_{2.5}$ pose a risk to human health.[91]

Thus, prevention strategies should be focused on continuous reduction of $PM_{2.5}$ rather than on peak days, and that air quality improvements will have effect almost immediately upon implementation. The U.S. EPA annual particulate concentration standard is set at 15.0 $\mu g/m^3$, arguing that there is no evidence for harm below this level.[92] The results of the Schwartz *et al.*[90] study directly contradict this line of reasoning.

Risk assessment. The risk assessment performed by the NRC,[20] found aggregate damages of $65 billion, including damages to public health, property, crops, forests, foregone recreation, and visibility due to emissions from coal-fired power plants of $PM_{2.5}$, PM_{10}, SO_2, NO_x, volatile organic compounds, and ozone. The public health damages included mortality cases, bronchitis cases, asthma cases, hospital admissions related to respiratory, cardiac, asthma, coronary obstructive pulmonary disease, and ischemic heart disease problems, and emergency room visits related to asthma. On a plant-by-plant basis after being normalized to electricity produced by each plant, this was 3.2 ¢/kWh. Plant-by-plant estimates of the damages ranged from 1.9 ¢/kWh to 12 ¢/kWh. Plant-to-plant variation was largely due to controls on the plant, characteristics of the coal, and the population downwind of the plant. Emissions of SO_2 were the most damaging of the pollutants affecting air quality, and 99% of this was due to SO_2 in the particle form.[20] The NRC study found that over 90% of the damages due to air quality are from $PM_{2.5}$-related mortality, which implies that these damages included approximately 8,158 excess mortality cases.[20] For the state of Kentucky alone, for each ton of SO_2 removed from the stack, the NRC (2009)[20] calculated a public health savings of $5,800. Removing the close to 500,000 tons emitted in Kentucky would save over $2.85 billion annually. The life cycle analysis found that damages from air quality public health impacts, monetized using methods from ExternE[26] are approximately $70.5 billion, which is roughly in line with this number.

The NRC's estimate is likely an underestimate, since the NRC used the concentration-response curve from Pope and Dockery,[83] which provides a low estimate for increases in mortality risk with increases in $PM_{2.5}$ exposure and is an outlier when compared to other studies examining the $PM_{2.5}$–mortality relationship.[6,87] Had they used the result of the more recent study by Schwartz *et al.*,[90] which was used in a similar study by Levy *et al.*,[21] or the number from Dockery *et al.*,[93] the value they calculated would have been approximately three times higher,[20] therefore implying 24,475 excess deaths in 2005, with a cost of $187.5 billion, or 9.3¢/kWh. As the Schwartz *et al.* study is more recent, uses elaborate statistical techniques to derive the concentration-response function for $PM_{2.5}$ and mortality, and is now widely accepted,[21,94] we use it here to derive our best and high estimate, and the Pope and Dockery,[83] estimate to derive our low. Our best and high estimates for the damages due to air quality detriment impacts are both $187.5 billion, and our low is $65 billion. On a per-kWh basis, this is an average cost of 9.3 ¢/kWh with a low estimate of 3.2 ¢/kWh.

Atmospheric nitrogen deposition. In addition to the impacts to air quality and public health, nitrogen causes ecological harm via eutrophication. Eutrophication, caused by excess nitrogen inputs to coastal river zones, is the greatest source of water quality alteration in the United States and atmospheric deposition is one of the dominant sources of nitrogen inputs.[95] In an analysis by Jaworkski *et al.*,[95] prepared for the EPA, 10 benchmark watersheds in the U.S. Northeast that flowed into the Atlantic coastal zone with good historical data were analyzed in conjunction with emissions data and reconstructed historical emissions. They found that the contribution to riverine nitrogen from nitrogen deposited from the air ranged from 36% to 80%, with a mean of 64%.

The other primary sources of nitrogen are fertilizers from point (e.g., river) discharges and nonpoint (e.g., agricultural land) sources, and other point sources including sewage from cities and farm animals, especially concentrated animal feeding operations.[95] Anthropogenic contributions of nitrogen are equal to the natural sources, doubling this form of fertilization of soils and water bodies.[96]

Harmful algal blooms and dead zones

Ocean and water changes are not usually associated with coal. But nitrogen deposition is a by-product of combustion and the EPA[97] has reached consensus on the link between aquatic eutrophication and harmful algal blooms (HABs), and concluded that nutrient over-fertilization is one of the reasons for their expansion in the United States and other nations. HABs are characterized by discolored water, dead and dying fish, and respiratory irritants in the air, and have impacts including illness and death, beach closures, and fish, bird, and mammal die-offs from exposure to toxins. Illnesses in humans include gastroenteritis, neurological deficits, respiratory illness, and diarrheic, paralytic, and neurotoxic shellfish poisonings.

N_2O from land clearing is a heat-trapping gas[38,42] and adds to the nitrogen deposited in soils and water bodies. The nitrogen is also a contributor to fresh and sea water acidification.[98–100] Other factors include the loss of wetlands that filter discharges.[98–100]

The economic losses from HABs are estimated to be over $82 million/year in the United States, based on the most prominent episodes.[101,102] The full economic costs of HABs include public health impacts and health care costs, business interruptions of seafood and other allied industries (such as tourism and recreation, unemployment of fin- and shellfish fisherman and their families), and disruptions of international trade.[98–100]

The overfertilization of coastal zones worldwide has also led to over 350 "dead zones" with hypoxia, anoxia, and death of living marine organisms. Commercial and recreational fisheries in the Gulf of Mexico generate $2.8 billion annually[103] and losses from the heavily eutrophied Gulf of Mexico dead zone put the regional economy at risk.

Acid precipitation. In addition to the health impacts of SO_2, sulfates contribute to acid rain, decreased visibility, and have a greenhouse cooling influence.[20]

The long-term Hubbard Brook Ecosystem Study[104] has demonstrated that acid rain (from sulfates and nitrates) has taken a toll on stream and lake life, and soils and forests in the United States, primarily in the Northeast. The leaching of calcium from soils is widespread and, unfortunately, the recovery time is much longer than the time it takes for calcium to become depleted under acidic conditions.[105]

No monetized values of costs were found but a value for the benefits of improvements to the Adirondack State Park from acid rain legislation was produced by Resources for the Future, and found benefits ranging from $336 million to $1.1 billion per year.[106]

Mercury. Coal combustion in the U.S. releases approximately 48 tons of the neurotoxin mercury each year.[54] The most toxic form of mercury is methylmercury, and the primary route of human exposure is through consumption of fin- and shellfish containing bioaccumulated methylmercury.[107] Methylmercury exposure, both dietary and *in utero* through maternal consumption, is associated with neurological effects in infants and children, including delayed achievement of developmental milestones and poor results on neurobehavioral tests—attention, fine motor function, language, visual-spatial abilities, and memory. Seafood consumption has caused 7% of women of childbearing age to exceed the mercury reference dose set by the EPA, and 45 states have issued fish consumption advisories.[107] Emission controls specific to mercury are not available, though 74–95% of emitted mercury is captured by existing emissions control equipment. More advanced technologies are being developed and tested.[107]

Direct costs of mercury emissions from coal-fired power plants causing mental retardation and lost productivity in the form of IQ detriments were estimated by Trasande *et al.*[22,23] to be $361.2 million and $1.625 billion, respectively, or 0.02¢/kWh and 0.1¢/kWh, respectively. Low-end estimates for these values are $43.7 million and $125 million, or 0.003¢/kWh and 0.007¢/kWh; high-end estimates for these values are $3.3 billion and $8.1 billion, or 0.19¢/kWh and 0.48¢/kWh.

There are also epidemiological studies suggesting an association between methylmercury exposure and cardiovascular disease.[108] Rice *et al.*[109] monetized the benefits of a 10% reduction in mercury emissions for both neurological development and cardiovascular health, accounting for uncertainty that the relationship between cardiovascular disease and methylmercury exposure is indeed causal. Applying these results for the cardiovascular benefits of a reduction in methylmercury to the 41% of total U.S. mercury emissions from coal[22,23] indicates costs of $3.5 billion, with low and high estimates of $0.2 billion and $17.9 billion, or 0.2 ¢/kWh, with low and high estimates of 0.014 ¢/kWh and 1.05 ¢/kWh.

Coal's contributions to climate change

The Intergovernmental Panel on Climate Change (IPCC) reported that annual global GHG emissions have—between 1970 and 2004—increased 70% to 49.0 Gt CO_2-e/year.[109] The International Energy Agency's Reference Scenario estimates that worldwide CO_2 emissions will increase by 57% between 2005 and 2030, or 1.8% each year, to 41,905 Mt.[1] In the same time period, CO_2 emissions from coal-generated power are projected to increase 76.6% to 13,884 Mt.[1]

In 2005, coal was responsible for 82% of the U.S.'s GHG emissions from power generation.[110] In addition to direct stack emissions, there are methane emissions from coal mines, on the order of 3% of the stack emissions.[110] There are also additional GHG emissions from the other uses of coal, approximately 139 Mt CO_2.[1]

Particulate matter (black carbon or soot) is also a heat-trapping agent, absorbing solar radiation, and, even at great distances, decreasing reflectivity (albedo) by settling in snow and ice.[111–113] The contribution of particulates (from coal, diesel, and biomass burning) to climate change has, until recently, been underestimated. Though short-lived, the global warming potential per volume is 500 times that of CO_2.[111]

Climate change

Since the 1950s, the world ocean has accumulated 22 times as much heat as has the atmosphere,[114] and the pattern of warming is unmistakably attributable to the increase in GHGs.[115] Via this ocean repository and melting ice, global warming is changing the climate: causing warming, altered weather patterns, and sea level rise. Climate may change gradually or nonlinearly (in quantum jumps). The release of methane from Arctic seas and the changes in Earth's ice cover (thus albedo), are two potential amplifying feedbacks that could accelerate the rate of Earth's warming.

Just as we have underestimated the rate at which the climate would change, we have underestimated the pace of health and environmental impacts. Already the increases in asthma, heat waves, clusters of illnesses after heavy rain events and intense storms, and in the distribution of infectious diseases are apparent.[116,117] Moreover, the unfolding impacts of climate instability hold yet even more profound impacts for public health, as the changes threaten the natural life-supporting systems upon which we depend.

The EIA[2] estimated that 1.97 billion tons of CO_2 and 9.3 million tons CO_2e of N_2O were emitted directly from coal-fired power plants. Using the social cost of carbon, this resulted in a total cost of $61.7 billion, or 3.06 ¢/kWh. Using the low and high estimates of the social cost of carbon results in cost of $20.56 billion to $205.6 billion, or 1.02 ¢/kWh to 10.2 ¢/kWh.

Black carbon emissions were also calculated using data from the EPA's eGRID database[81] on electricity produced from lignite. The low, mean, and high energy density values for lignite[5] was then used to calculate the amount of lignite consumed. The Cooke *et al.*[118] emissions factor was used to estimate black carbon emissions based on lignite use and the Hansen *et al.*[111] global temperature potential was used to convert these emissions to CO_2e. This resulted in an estimate of 1.5 million tons CO_2e being emitted in 2008, with a value of $45.2 million, or 0.002¢/kWh. Using our low and high estimates for the social cost of carbon and the high and low values for the energy density of lignite produced values of $12.3 million to $161.4 million, or 0.0006 ¢/kWh to 0.008¢/kWh.

One measure of the costs of climate change is the rising costs of extreme weather events, though these are also a function of and real estate and insurance values. Overall, the costs of weather-related disasters rose 10-fold from the 1980s to the 1990s (from an average of $4 bn/year to $40 bn/year) and jumped again in the past decade, reaching $225 bn in 2005.[119] Worldwide, Munich Re—a company that insures insurers—reports that, in 2008, without Katrina-level disasters, weather-related "catastrophic losses" to the global economy were the third-highest in recorded history, topping $200 billion, including $45 billion in the United States.[120]

The total costs of climate change damages from coal-derived power, including black carbon, CO_2 and N_2O emissions from combustion, land disturbance in MTR, and methane leakage from mines, is $63.9 billion dollars, or 3.15 ¢/kWh, with low and high estimates of $21.3 billion to $215.9 billion, or 1.06 ¢/kWh to 10.71 ¢/kWh. A broad examination of the costs of climate change[121] projects global economic losses to between 5 and 20% of global gross domestic product ($1.75–$7 trillion in 2005 US$); the higher figure based on the potential collapse of ecosystems, such as coral reefs and widespread forest and crop losses. With coal contributing at least one-third of the heat-trapping chemicals, these projections offer a sobering perspective on the evolving costs of coal; costs that can be projected to rise (linearly or nonlinearly) over time.

Carbon capture and storage

Burning coal with CO_2 CCS in terrestrial, ocean, and deep ocean sediments are proposed methods of deriving "clean coal." But—in addition to the control technique not altering the upstream life cycle costs—significant obstacles lie in the way, including the costs of construction of suitable plants

Table 2. MIT cost estimates for some representative CCS systems.[5]

		Subcritical PC		Supercritical PC		Ultra-supercritical PC		SC PC-Oxy	IGCC	
		No capture	Capture	No capture	Capture	No capture	Capture	Capture	No capture	Capture
CCS performance	Coal feed (kg/hr)	208,000	284,000	184,894	242,950	164,000	209,000	232,628	185,376	228,115
	CO_2 emitted (kg/hr)	466,000	63,600	414,903	54,518	369,000	46,800	52,202	415,983	51,198
	CO_2 captured at 90%, (kg/h)	0	573.000	0	490662	0	422000	469817	0	460782
	CO_2 emitted (g/kWh)	931	127	830	109	738	94	104	832	102
CCS costs	$/kWh	1,280	2,230	1,330	2,140	1,360	2,090	1,900	1,430	1,890
	Total $, assuming 500 MW plant	$640,000, 000	$1,115,000, 000	$665,000, 000	$1,070,000, 000	$680,000, 000	$1,045,000, 000	$950,000, 000	$715,000, 000	$945,000, 000
	Inv. Charce ¢/kWh @ 15.1%	2.6	4.52	2.7	4.34	2.76	4.24	3.85	2.9	3.83
	Fuel ¢/kWh @ $1.50/MMBtu	1.49	2.04	1.33	1.75	1.18	1.5	1.67	1.33	1.64
	O&M ¢/kWh	0.75	1.6	0.75	1.6	0.75	1.6	1.45	0.9	1.05
	COE ¢/kWh	4.84	8.16	4.78	7.69	4.69	7.34	8.98	5.13	6.52
	Cost of CO_2 avoided vs. same technology w/o capture ($/ton)		41.3		40.4		41.1	30.3		19.3
	Cost of CO_2 avoided vs. supercritical technology w/o capture ($/ton)		48.2		40.4		34.8	30.3		24
	Energy penalty		1,365, 384,615		1,313, 996,128		1,274, 390,244			1,230, 553,038

and underground storage facilities, and the "energy penalty" requiring that coal consumption per unit of energy produced by the power plant increase by 25–40% depending on the technologies used.[4,42]

Retrofitting old plants—the largest source of CO_2 in the United States—may exact an even larger energy penalty. The energy penalty means that more coal is needed to produce the same quantity of electricity, necessitating more mining, processing, and transporting of coal and resulting in a larger waste stream to produce the same amount of electricity. Coal-fired plants would still require locally polluting diesel trucks to deliver the coal, and generate CCW ponds that can contaminate ground water. Given current siting patterns, such impacts often fall disproportionately on economically disadvantaged communities. The energy penalty combined with other increased costs of operating a CCS plant would nearly double the cost of generating electricity from that plant, depending on the technology used (see Table 2).[5]

The U.S. Department of Energy estimates that an underground volume of 30,000 km^2 will be needed per year to reduce the CO_2 emissions from coal by 20% by 2050 (the total land mass of the continental U.S. (48 states) is 9,158,960 km^2).[122]

The safety and ensurability of scaling up the storage of the billion tons of CO_2 generated each year into the foreseeable future are unknown. Extrapolating from localized experiments, injecting fractions of the volumes that will have to be stored to make a significant difference in emissions, is fraught with numerous assumptions. Bringing CCS to scale raises additional risks, in terms of pressures underground. In addition to this, according to the U.S. Government Accountability Office (2008) there are regulatory, legal and liability uncertainties, and there is "significant cost of retrofitting existing plants that are single largest source of CO_2 emissions in the United States" (p. 7).[123]

Health and environmental risks of CCS

The Special IPCC Report on Carbon Dioxide Capture and Storage[42] lists the following concerns for CCS in underground terrestrial sites:

1. Storing compressed and liquefied CO_2 underground can acidify saline aquifers (akin to ocean acidification) and leach heavy metals, such as arsenic and lead, into ground water.[42]
2. Acidification of ground water increases fluid-rock interactions that enhance calcite dissolution and solubility, and can lead to fractures in

limestone ($CaCO_3$) and subsequent releases of CO_2 in high concentrations.[124]
3. Increased pressures may cause leaks and releases from previously drilled (often unmapped) pathways.
4. Increased pressures could destabilize underground faults and lead to earthquakes.
5. Large leaks and releases of concentrated CO_2 are toxic to plants and animals.[42]
   a. The 2006 Mammoth Mountain, CA release left dead stands of trees.[124]
6. Microbial communities may be altered, with release of other gases.[42]

The figures in Table 2 represent costs for new construction. Costs for retrofits (where CCS is installed on an active plant) and rebuilds (where CCS is installed on an active plant and the combustion technology is upgraded) are highly uncertain because they are extremely dependent on site conditions and precisely what technology the coal plant is upgraded to.[5] It does appear that complete rebuilds are more economically attractive than retrofits, and that "carbon-capture ready" plants are not economically desirable to build.[5]

Subsidies

In Kentucky, coal brings in an estimated $528 million in state revenues, but is responsible for $643 million in state expenditures. The net impact, therefore, is a loss of $115 million to the state of Kentucky.[126] These figures do not include costs of health care, lost productivity, water treatment for siltation and water infrastructure, limited development potential due to poor air quality, and social expenditures associated with declines in employment and related economic hardships of coal-field communities.[126]

The U.S. Federal Government provides subsides for electricity and mining activities, and these have been tallied by both the EIA and the Environmental Law Institute.[2,127,128] The EIA estimate is $3.17 billion of subsidies in 2007, or 0.16¢/kWh, and the Environmental Law Institute estimate is $5.37 billion for 2007, or 0.27¢/kWh.

Abandoned mine lands

Abandoned mine lands (AML) are those lands and waters negatively impacted by surface coal mining and left inadequately reclaimed or abandoned prior to August 3, 1977.[129] There are over 1,700 old abandoned mines in Pennsylvania, alone.[14] In some—like that in Centralia, PA—fires burn for decades, emitting carbon monoxide, and other fumes. The ground above others can open, and several people die each year falling into them. Still others flood and lead to contaminated ground water. Previous coal mining communities lie in the shadow of these disturbed areas. Officials in Pennsylvania estimate that it will take $15 billion over six decades to clean Pennsylvania's abandoned mines.

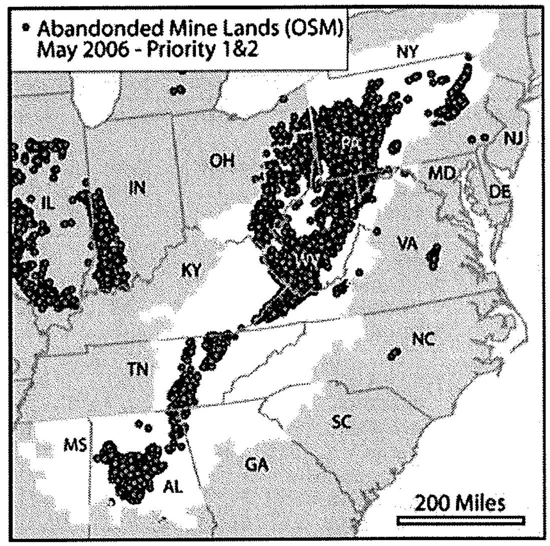

Figure 4. Current high-priority abandoned mine land reclamation sites from Alabama to Pennsylvania.[129] (In color in *Annals* online.) Source: Hope Childers, Wheeling Jesuit University.

Since the passage of the Surface Mining Control and Reclamation Act of 1977, active mining operations have been required to pay fees into the Abandoned Mine Reclamation Fund that are then used to finance reclamation of these AMLs.[129] Despite the more than $7.4 billion that has been collected as of September 30, 2005, there is a growing backlog of unfunded projects.[51] Data on the number and monetary value of unfunded AML projects remaining at the end of 2007 for the nation were collected directly from the Abandoned Mine Land Inventory System[129] and amounted to $8.8 billion 2008 US$, or 0.44¢/kWh (Fig. 4).

Results

The tabulation of the externalities in total and converted to 2008 US$ is given in Table 3 and normalized to cents per kWh of coal-generated electricity

Table 3. The complete costs of coal as reviewed in this report in 2008 US$.

	Monetized estimates from literature (2008 US$)			Monetized life cycle assessment results (2008 US$)	
	Low	Best	High	IPCC 2007, U.S. Hard Coal	U.S. Hard Coal Eco-indicator
Land disturbance	$54,311,510	$162,934,529	$3,349,209,766		
Methane emissions from mines	$684,084,928	$2,052,254,783	$6,840,849,276	$2,188,192, 405	
Carcinogens (mostly to water from waste)					$11,775,544, 263
Public health burden of communities in Appalachia	$74,612,823,575	$74,612,823,575	$74,612,823,575		
Fatalities in the public due to coal transport	$1,807,500,000	$1,807,500,000	$1,807,500,000		
Emissions of air pollutants from combustion	$65,094,911,734	$187,473,345,794	$187,473,345,794		$71,011,655, 364
Lost productivity from mercury emissions	$125,000,000	$1,625,000,000	$8,125,000,000		
Excess mental retardation cases from mercury emissions	$43,750,000	$361,250,000	$3,250,000,000		
Excess cardiovascular disease from mercury emissions	$246,000,000	$3,536,250,000	$17,937,500,000		
Climate damages from combustion emissions of CO_2 and N_2O	$20,559,709,242	$61,679,127,726	$205,597,092,419.52	$70,442,466, 509	
Climate damages from combustion emissions of black carbon	$12,346,127	$45,186,823	$161,381,512.28	$3,739,876, 478	
Environmental Law Institute estimate 2007			$5,373, 963,368		
EIA 2007	$3,177,964,157	$3,177, 964,157			
AMLs	$8,775,282,692	$8,775, 282,692	$8,775, 282,692		
Climate total	$21,310,451,806	$63,939,503,861	$215,948,532,974		
Total	$175,193,683,964	$345,308,920,080	$523,303,948,403		

A 2010 Clean Air Task Force[56] (CATF) report, with Abt Associates consulting, lists 13,000 premature deaths due to air pollution from all electricity generation in 2010, a decrease in their estimates from previous years. They attribute the drop to 105 scrubbers installed since 2005, the year in which we based our calculations. We were pleased to see improvements reported in air quality and health outcomes. There is, however, considerable uncertainty regarding the actual numbers. Using the epidemiology from the "Six Cities Study" implies up to 34,000 premature deaths in 2010. Thus, our figures are mid-range while those of the CATF represent the most conservative of estimates.

in Table 4. Our best estimate for the externalities related to coal is $345.3 billion (range: $175.2 bn to $523.3 bn). On a per-kWh basis this is 17.84¢/kWh, ranging from 9.42 ¢/kWh to 26.89 ¢/kWh.

Limitations of this analysis

While we have based this analysis on the best available data that are used by a wide range of organizations, this review is limited by the omission of many environmental, community, mental health, and economic impacts that are not easily quantifiable. Another limitation is the placing of numbers on impacts that are difficult to quantify or monetize, including the VSL, a crude estimate of the benefits of reducing the number of deaths used by economists, and the social cost of carbon, based on the evolving impacts of climate change. We have included ranges, reflecting the numerous sets of data and studies in this field (all of which have their own

Table 4. Total costs of coal normalized to kWh of electricity produced.

	Monetized estimates from literature in ¢/kWh of electricity (2008 US$)			Monetized life cycle assessment results in ¢/kWh of electricity (2008 US$)	
	Low	Best	High	IPCC 2007, U.S. Hard Coal	U.S. Hard Coal Eco-indicator
Land disturbance	0.00	0.01	0.17		
Methane emissions from mines	0.03	0.08	0.34	0.11	
Carcinogens (mostly to water from waste)					0.60
Public health burden of communities in Appalachia	4.36	4.36	4.36		
Fatalities in the public due to coal transport	0.09	0.09	0.09		
Emissions of air pollutants from combustion	3.23	9.31	9.31		3.59
Lost productivity from mercury emissions	0.01	0.10	0.48		
Excess mental retardation cases from mercury emissions	0.00	0.02	0.19		
Excess cardiovascular disease from mercury emissions	0.01	0.21	1.05		
Climate damage from combustion emissions of CO_2 and N_2O	1.02	3.06	10.20	3.56	
Climate damages from combustion emissions of black carbon	0.00	0.00	0.01	0.19	
Environmental Law Institute estimate 2007			0.27		
EIA 2007	0.16	0.16			
AMLs	0.44	0.44	0.44		
Climate total	1.06	3.15	10.7	3.75	1.54
Total	9.36	17.84	26.89		

uncertainties), varying assumptions in data sets and studies, and uncertainties about future impacts and the costs to society.

Some of the issues raised apply only to the region discussed. Decreased tourism in Appalachia, for example, affects regional economies; but may not affect the overall economy of the United States, as tourists may choose other destinations.

Studies in Australian coal mining communities illustrate the cycle of economic boom during construction and operation, the economic and worker decoupling from the fortunes of the mines; then the eventual closing.[130] Such communities experience high levels of depression and poverty, and increases in assaults (particularly sexual assaults), motor vehicle accidents, and crimes against property, until the culture shifts to allow for development of secondary industries. Additional evidence documents that mining-dependent economies tend to be weak economies,[131] and weak economic conditions in turn are powerful predictors of social and health disadvantages.[130,132]

Some values are also difficult to interpret, given the multiple baselines against which they must be compared. In assessing the "marginal" costs of environmental damages, we have assumed the diverse, pristine, hardwood forest that still constitutes the majority of the beautiful rich and rolling hills that make up the Appalachian Mountain range.

Ecological and health economic analyses are also affected by the discount rate used in such evaluations. Discount rates are of great value in assessing the worth of commodities that deteriorate over time. But they are of questionable value in assessing ecological, life-supporting systems that have value if they are sustained. Ecological economists might consider employing a negative discount rate—or an accrual rate—in assessing the true impacts of environmental degradation and the value of sustainability.

Finally, the costs reported here do not include a wide range of opportunity costs, including lost opportunities to construct wind farms and solar power plants, begin manufacture of wind turbines and solar technologies, develop technologies for the smart grid and transmission, and for economic and business development unrelated to the energy sector.

Conclusions

The electricity derived from coal is an integral part of our daily lives. However, coal carries a heavy burden. The yearly and cumulative costs stemming from the aerosolized, solid, and water pollutants associated with the mining, processing, transport, and combustion of coal affect individuals, families, communities, ecological integrity, and the global climate. The economic implications go far beyond the prices we pay for electricity.

Our comprehensive review finds that the best estimate for the total economically quantifiable costs, based on a conservative weighting of many of the study findings, amount to some $345.3 billion, adding close to 17.8¢/kWh of electricity generated from coal. The low estimate is $175 billion, or over 9¢/kWh, while the true monetizable costs could be as much as the upper bounds of $523.3 billion, adding close to 26.89¢/kWh. These and the more difficult to quantify externalities are borne by the general public.

Still these figures do not represent the full societal and environmental burden of coal. In quantifying the damages, we have omitted the impacts of toxic chemicals and heavy metals on ecological systems and diverse plants and animals; some ill-health endpoints (morbidity) aside from mortality related to air pollutants released through coal combustion that are still not captured; the direct risks and hazards posed by sludge, slurry, and CCW impoundments; the full contributions of nitrogen deposition to eutrophication of fresh and coastal sea water; the prolonged impacts of acid rain and acid mine drainage; many of the long-term impacts on the physical and mental health of those living in coal-field regions and nearby MTR sites; some of the health impacts and climate forcing due to increased tropospheric ozone formation; and the full assessment of impacts due to an increasingly unstable climate.

The true ecological and health costs of coal are thus far greater than the numbers suggest. Accounting for the many external costs over the life cycle for coal-derived electricity conservatively doubles to triples the price of coal per kWh of electricity generated.

Our analysis also suggests that the proposed measure to address one of the emissions—CO_2, via CCS—is costly and carries numerous health and environmental risks, which would be multiplied if CCS were deployed on a wide scale. The combination of new technologies and the "energy penalty" will, conservatively, almost double the costs to operate the utility plants. In addition, questions about the reserves of economically recoverable coal in the United States carry implications for future investments into coal-related infrastructure.

Public policies, including the Clean Air Act and New Source Performance Review, are in place to help control these externalities; however, the actual impacts and damages remain substantial. These costs must be accounted for in formulating public policies and for guiding private sector practices, including project financing and insurance underwriting of coal-fired plants with and without CCS.

Recommendations

1. Comprehensive comparative analyses of life cycle costs of all electricity generation

technologies and practices are needed to guide the development of future energy policies.
2. Begin phasing out coal and phasing in cleanly powered smart grids, using place-appropriate alternative energy sources.
3. A healthy energy future can include electric vehicles, plugged into cleanly powered smart grids; and healthy cities initiatives, including green buildings, roof-top gardens, public transport, and smart growth.
4. Alternative industrial and farming policies are needed for coal-field regions, to support the manufacture and installation of solar, wind, small-scale hydro, and smart grid technologies. Rural electric co-ops can help in meeting consumer demands.
5. We must end MTR mining, reclaim all MTR sites and abandoned mine lands, and ensure that local water sources are safe for consumption.
6. Funds are needed for clean enterprises, reclamation, and water treatment.
7. Fund-generating methods include:
   a. maintaining revenues from the workers' compensation coal tax;
   b. increasing coal severance tax rates;
   c. increasing fees on coal haul trucks and trains;
   d. reforming the structure of credits and taxes to remove misaligned incentives;
   e. reforming federal and state subsidies to incentivize clean technology infrastructure.
8. To transform our energy infrastructure, we must realign federal and state rules, regulations, and rewards to stimulate manufacturing of and markets for clean and efficient energy systems. Such a transformation would be beneficial for our health, for the environment, for sustained economic health, and would contribute to stabilizing the global climate.

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Conflicts of interest

The authors declare no conflicts of interest.

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Limiting the costs of renewable portfolio standards: A review and critique of current methods

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ABSTRACT

Over half of U.S. states have renewable portfolio standards (RPSs) mandating that a minimum percentage of electricity sold derives from renewable sources. State RPSs vary widely in how they attempt to control or limit the costs of these RPSs. Approaches utilized include alternative compliance payments, direct rate caps, and cost caps on resource acquisitions, while some states employ no specific limitation at all. This paper describes how states attempt to control RPS costs and discusses the strengths and weaknesses of these various cost controls. There is no one best method; however the experience to date suggests that the most important factors in implementing an effective mechanism to curtail costs are clarity of the rule, consistency in application, and transparency for customers.

1. Introduction

Currently twenty-nine states plus the District of Columbia and Puerto Rico[1] have enacted Renewable Portfolio Standards ("RPSs") mandating that a specified percentage of the electricity sector's energy derives from renewable sources. (www.dsireusa.org). These RPSs generally (although not always) increase the wholesale costs of electricity to utilities with the attendant costs being passed on to consumers. One estimate found that state RPSs, on average, have thus far increased electricity rates by about one percent (Wiser and Barbose, 2008). However, the mechanisms for calculating these impacts vary considerably from state to state. Future cost impacts are of course more difficult to calculate (Chen et al., 2007). As state RPSs ramp up their renewable targets and solar and distributed generation set-asides in coming years, RPS cost impacts will be an increasing concern for industry and customers alike.

State legislators, public utility commissions, and other regulatory agencies have struggled to manage the costs of implementing their RPSs in the face of political pressure and statutory mandates to protect ratepayers from excessive costs of RPS compliance. For example, according to one staff member of the New Mexico Public Service Commission, electricity rates have increased four to five percent over the past six years due to the RPS requirements. Many states thus utilize mechanisms to curtail what electricity providers spend, and consequently what ratepayers must pay, to implement their RPSs.

This paper explains the primary cost limitation mechanisms being used today, discusses differences in design across states, and draws conclusions about how such mechanisms should be designed and implemented. A summary of states' cost impact limitation mechanisms is shown in Table 1.

2. Review of utility regulation and restructuring

The U.S. electricity market is an eclectic mix of traditionally regulated (or "cost-of-service") utilities—whose prices are regulated by a government body—and restructured (also known as "competitive") markets, in which multiple retail providers compete for customers. While most states operate as either regulated or competitive markets, a few employ a hybrid of both approaches. For example, in Oregon and Nevada, respectively, only commercial and industrial customers and very large customers have the freedom to choose their electric suppliers. Restructured power markets with retail choice operate in the Northeast, the Mid-Atlantic, Texas, Oregon, and parts of the Midwest. In Table 1 traditionally regulated states are shown in standard font, restructured states in *italics*, and hybrid states in <u>*underlined italics*</u>.

It is useful to briefly review how utilities operating under a cost-of-service model recover costs as compared to those operating in a restructured market because RPS cost limitation mechanisms often derive from cost recovery calculations. For example, utilities held to a cap on retail revenue requirements must make calculations and projections that generally arise in rate-making procedures. Additionally, although regulatory structure is not the

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[1] This paper focuses on the approaches of the twenty-nine states.

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Table 1
Summary of states' cost limitation mechanisms. States with restructured electricity markets are shown in italics, hybrid states in underlined italics, and traditionally regulated states in standard font. States in parentheses utilize a mechanism analogous to the listed cost limitation.

Approach	Description	States
Annual cost caps		
on utilities' annual revenue requirement	Limits additional costs as % of expected annual net retail revenue requirement.	Kansas, *Ohio*, *Oregon*, Washington, (*Maryland, Delaware, Maine*)[a]
Retail rate impact limitation	Limits additional costs as % of expected total of customers' bills.	Colorado, *Illinois*, Missouri, New Mexico
Set surcharge on customers' bills	Caps monthly surcharge on customers' bills at a set amount.	Arizona[b], *Michigan*, North Carolina
Cap on total expenditures	Above-market price contracts limited by total fund of $770+ million allocated among IOUs.	*California*
Alternative compliance payment	Sets an amount utilities pay to a central fund instead of procuring renewable energy; serves as de facto cap.	*Connecticut, D.C., Delaware, Illinois, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, Ohio, Oregon, Pennsylvania, Rhode Island, (Texas)*[c]
Public benefits funds	Funds renewable energy in the state, thus indirectly mitigating cost impacts to consumers of RPS requirements. Often Alternative Compliance Payments fund PBFs.	*Connecticut, D.C., Delaware, Illinois, Maine, Massachusetts, , New Hampshire, New Jersey, New York*[d], *Ohio, Oregon, Pennsylvania, Rhode Island*, (*California*, Minnesota, *Michigan*, *Montana*, Wisconsin)[e]
Cap on individual contracts	Limits procurement of contracts priced above set % above market-price.	*Montana*, Hawaii
Ad hoc agency discretion:		
No cost cap, "just and reasonable" review	No set limitations on costs. PUCs use traditional reasonableness review. May include waivers.	Iowa, Minnesota, Wisconsin
Rider review	PUC reviews utilities' riders under just and reasonable standard	Arizona, Eastern Wisconsin
Contract review	PUC reviews procurement contracts under modified just and reasonable standard.	*Nevada*
Other off-ramps (waivers, freezes)[f]		Arizona, *California*, Colorado, *Connecticut*, *Delaware*, Hawaii, *Illinois*, *Maryland*, *Maine*, *Michigan*, Minnesota, Missouri, *Montana*, *Nevada*, *New Hampshire*, *New Jersey*, New Mexico, North Carolina, *Ohio*, *Oregon*, *Pennsylvania*, *Rhode Island*, *Texas*, Washington, Wisconsin

[a] These states use alternative compliance mechanisms, but also have an "off-ramp" provision which allows a utility to request delays or waivers of its compliance if it can prove compliance costs exceed a set % of its annual sales revenues.
[b] Utilities may adopt the sample tariff, or one "substantially similar." This provides more flexible surcharge pricing than N.C. or Michigan.
[c] Texas's penalty provision may constitute a de facto price ceiling, analogous to an alternative compliance mechanism. PUCT Substantive Rule 25.173(p).
[d] New York's PBF, centrally administered, is funded by a non-bypassable volumetric "System benefits/RPS charge" applied to all major utilities' customers' bills.
[e] These states have PBFs that are not funded by ACPs.
[f] For a comprehensive list of waivers, see Union of Concerned Scientists' RPS Toolkit on Escape Clauses, at http://go.ucsusa.org/cgi-bin/RES/state_standards.

determining factor, the absence of regulatory rate-making oversight in restructured states appears to favor the use of alternative compliance mechanisms and public benefits funds which are more readily implemented in those markets.

In a cost of service jurisdiction, utilities are entitled to a monopoly in their service area and a fair rate of return on capital investments in return for their commitment to serve the public with reliable and non-discriminatory service. The rate of return is calculated based on the interest rates of utilities' liabilities (in debt and equity). When a retail utility is faced with an earnings shortfall, due for example to the projected costs of a new power plant or new regulatory requirements, it undergoes a rate proceeding conducted by the state's public utility commission. In a "rate case," the utility must demonstrate its projected net revenue requirement for a test year including its variable operating costs, annual fixed costs, expected depreciation, and tax gross-up. Traditionally, the test year has been a historic year. Increasingly, regulatory commissions are allowing utilities to establish rates on the basis of anticipated costs of a future test year. Annual fixed costs are calculated as the utility's fixed capital or rate base multiplied by its commission approved rate of return which is typically based on its weighted average cost of capital. Thus derives the classic formula in the cost of service regime:

$$R = O + B(r)$$

where R is the net revenue requirement, O the operating costs, B the capital costs, or "rate base," and r the rate of return.

In a separate proceeding for rate design, rates are determined, among other things, by allocating big R among various ratepayer classes. One major critique of the cost of service model is that, because recovery is prospectively based on the utility's estimates of operating costs, rate base, and rate of return of a historic or future test year, a utility is likely to over- or under-recover its actual costs in the coming years. Another concern is that utilities are motivated to maximize their retail revenue requirements to increase profits. These criticisms may be applicable to the budgeting approaches described herein for cost-of-service utilities.

In restructured states such as Texas, Maryland, and New York, retail electricity providers recover their costs of capital investment through direct sales in the market. There are no rate proceedings, although regulators may retain discretion to freeze rates or otherwise protect consumers if competition fails to do so. Several vertically integrated investor-owned utilities remain in partially restructured states, such as Illinois, where traditional cost-of-service models apply. Cost recovery in restructured states is not assured and providers must look to market forces to allocate their budgets, even in the face of mandates to acquire expensive new renewable resources.

3. Annual cost caps

An appealingly simple approach to limiting RPS costs is to cap the annual costs of implementation. In practice, however, cost caps can be quite complex and suffer from a lack of transparency.

3.1. Cap on utilities' annual revenue expenditure

Several states cap utilities' expenditures on renewable resources for RPS compliance at a set percentage of the utilities' annual retail revenue requirements (the R in the rate case formula $R=O+B(r)$). In these states, utilities that spend a specified percentage of their annual revenue requirement on renewables may be deemed in compliance with the RPS even if they have not met the annual RPS targets. The general formula for this cost cap is

$$C_{RetailRevenue} = \frac{I_{renewables} + I_{alternatives}}{R} \times 100$$

where $C_{Retail\ Revenue}$ is the retail revenue percentage, $I_{renewables}$ the incremental cost of renewable resources, $I_{alternatives}$ the annual costs of alternative compliance mechanisms (renewable energy credits, alternative compliance payments), R the net retail revenue requirement.

It should be noted, however, that only Oregon and Washington strictly set the denominator above to R. Although the Kansas cost cap excuses utilities from penalties for noncompliance if the "incremental rate impact of renewables" exceeds one percent, the impact is based on the revenue requirement from the last rate case.[2] In the restructured state of Ohio, the incremental costs of compliance are compared against "reasonable expected costs of generation" which may not necessarily include the traditional elements of R, depreciation, tax gross-up, and a rate of return.[3] These states are nonetheless discussed herein as their approaches are procedurally similar to, and raise similar concerns as, a strict revenue requirement cap. Overall, the most contentious aspect of this approach is typically how to determine the incremental cost of the renewable resources. With many state RPSs just underway, many states are still working through such determinations.

Ohio, Oregon, Kansas, and Washington utilities all count the levelized annual "incremental costs" of obtaining eligible renewable resources against the cap. The Washington legislature requires utilities to calculate this levelized incremental cost as the difference between the levelized delivered cost of the eligible renewable resource, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resources that do not qualify as eligible renewable resources, where the resources being compared have the same contract length or facility life (Wa. Admin. Code §§ 194-37-170 et seq, 2011). Oregon's mandate further clarifies that the calculation of levelized annual incremental costs should capture the costs of capital, operating costs, financing, transmission and distribution costs, load following and ancillary services, additional assets, and R&D (Or. Rev. Stat. §§ 469A.100 et seq, 2011). Ohio utilities, on the other hand, may not count against its three percent cap those "construction or environmental expenditures of generation resources" that are commission-approved and passed on to consumers through a surcharge (Ohio Admin. Code § 4901:1-40-07). The substitute non-qualifying resources against which the costs of renewables are compared may vary, although most states currently use a natural gas-fired resource as the proxy resource to represent the cost of non-qualifying electricity (OPUC, 2009).

In addition to the costs of any built renewable resources, the actual annual costs of meeting a state's RPS also often include the costs of renewable energy credits ("RECs"), of acquiring renewable resources via power purchase agreements ("PPAs") or on the spot market, and alternative compliance payments ("ACPs") if the RPS permits. States differ on whether these costs count in the cap. Oregon's cap of four percent of a utility's annual net retail requirement includes the incremental levelized costs of building renewables, as discussed above, as well as the cost of unbundled RECs, and the cost of ACPs (Or. Rev. Stat. §§ 469A.100 et seq, 2011). In Ohio, utilities may not count ACPs toward the cap nor may they recover ACP payments from ratepayers (Rev. Code Ohio § 4928.64, 2011). This limitation reduces the likelihood that utilities will rely on ACPs to meet the RPS unless faced with harsher penalties for noncompliance. For the integrity of the cap, the incremental costs of compliance should be least-cost measures. For this purpose, Washington and Oregon provide that only "prudently incurred costs" are recoverable, a point that will likely be argued in ratemaking or RPS compliance proceedings (Wa. Stat. § 19.285.050, 2011; Or. Rev. Stat. §§ 469A.100 et seq, 2011).

With respect to the denominator of the above equation, states appear generally to allow utilities to base the annual revenue requirement or its analog on a future test year. Washington is one such example (Rev. Code Wa. 19.285.050, 2011; Wa. Admin. Code, §§ 194-37-170 et seq, 2011). In Ohio, too, utilities may compare incremental costs against the "reasonable expected costs of generation" (Ohio Admin. Code § 4901:1-40 et seq, 2011; Ohio Rev. Code Ann. § 4928.64, 2011). An alternative to basing R on the projections of a coming year would be to set the cap off a prior year or of some specified average. Kansas bases its impact calculus on the R used in a utility's previous rate case. Such an approach likely results in a cap that is more certain, less administratively burdensome, and more evenly administered amongst utilities. Another important consideration is whether utilities exclude the incremental compliance costs (the numerator of the cap) from the total net revenue requirement. Oregon excludes these costs so as not to inflate the revenue requirement above that which is required using only conventional resources. Without this modification, the revenue requirement assumes the presence of eligible renewable resources and thereby increases the funds available for renewables under the cap.

Apart from how the cap is calculated, states may choose to implement the cap as either mandatory or voluntary. The Washington legislature made clear, for example, that its cap is voluntary: "a utility may elect to invest more than [the] amount" set forth in the four percent rate cap, and will still be entitled to recover its prudently incurred costs of complying with the RPS (Rev. Code Wa. 19.285.050, 2011). Oregon, Ohio, and Kansas are also voluntary, leaving spending ultimately to the utilities' discretion though presumably subject to approval by their respective commissions.

Finally, states may use a variation of this retail revenue impact as an optional "off-ramp" (or waiver) provision where prices for the RPS are getting too high. In Maryland, in addition to alternative compliance payments, utilities may request that the Maryland Public Service Commission delay the incremental increases in renewable targets if the actual or anticipated cost of compliance is for solar, greater than or equal to 1% of the electric supplier's total annual electricity sales revenues; or for non-solar resources, the greater of 10% of electricity supplier's total annual retail sales or the Tier 1 percentage requirement for that year (Md. Pub. Util. Co. Code §§ 7-701 et seq, 2011).

3.2. Rate cap

Related but not equivalent to a cap on annual net retail revenue requirements is an annual rate impact limitation or "rate cap." A utility's annual retail revenue requirement or the equivalent in deregulated states is apportioned among various ratepayer classes to derive unit rates. The rate cap limits RPS compliance expenditures to an amount that raises the rates of different

[2] Kansas Corporation Commission Staff has expressed concern with the rules and how they should be applied going forward.

[3] No utility has yet triggered Ohio's cost cap and so there is no formal guidance on how the state agency will interpret the provisions of the statute and the implementing rules.

customer classes by a set percentage over a specified period of time. Thus, the formula for this approach generally follows:

$$C_{ratecap} = (l)(B_{net})$$

where $C_{rate\ cap}$ is the rate cap, l the % rate impact limitation, and B_{net} the customers' bills.

Applications of this formula vary, however. The rate impact limitation may be calculated incrementally, or averaged cumulatively over a longer period of time. Customers' bills, B_{net}, may be based on customers' actual costs, or more similarly to the retail revenue requirement cap, on their projected costs.

An incremental rate cap specifies the allowable rate increase for a given year. Colorado's cap authorizes its investor-owned utilities to collect up to two percent of customers' bills annually for the purpose of meeting the RPS (Colo. Code Reg., 4 CCR 723-3-3661(a), 2011). New Mexico's cap ramps up to three percent of customers' aggregated annual electric bills by 2015 (N.M. Admin. Code § 17.9.572.11(C), 2011). Illinois's investor-owned utilities, by 2012, are limited to spending the greater of either an additional 2.015% of the amount paid per kilowatt-hour by eligible customers during the 2007 baseline year or an additional 0.5% of the amount paid per kilowatt-hour by those customers during the previous year on renewable energy resources procured pursuant to the RPS (Ill. Comp. Stat. 20 ILCS 3855/1-75(c), 2011).

In contrast, a cumulative or average rate cap limits the rate increase over a longer period of time. Missouri uses a hybrid cumulative annual rate cap that poses some interesting issues in design and efficacy. Based on the mandate of Missouri's legislature, as of January 2011, utilities in Missouri may spend up to the "maximum average retail rate" increase of one percent to implement the RPS (Rev. Stat. Mo. § 393.1030.2(1), 2010). The Missouri Public Service Commission ("PSC") decided that, in light of the "average" language and the goal of smoothing out "spikes in compliance costs and recovery caused by new technology coming on-line in the beginning of implementation" (Missouri Register, 2010)) the rate cap would be both cumulative over a ten-year period and calculated annually. The planned approach requires utilities to estimate their incremental costs of compliance for each year, based on the difference in levelized costs of a portfolio under the RPS and one without, over a ten-year period. The average annual increase over this succeeding ten year period should not surpass one percent (Mo. Code State Reg., 4 CSR 240-20.100(5)(A), 2011). On its face, this approach appears to limit the annual incremental cost of compliance to approximately one percent of customers' bills for that year while allowing some years to cost more, others less. Yet regulators in the state admit they are worried about how this will work administratively.

Otherwise, the rate cap approach creates many of the same issues inherent to the net retail revenue impact discussed above: what costs of compliance count toward the incremental costs of compliance; what avoided costs establish the base against which the impact is measured; and is the cap mandatory or voluntary? The rate caps in Colorado, Illinois, and Missouri are statutory and mandatory. In Colorado, because utilities have been allowed to loan money into the renewable fund (and earn interest thereon), the cap has not actually served to limit utility expenditures on renewables and this has become an important point of contention. In New Mexico, utilities may petition the New Mexico Public Regulation Commission for a waiver of any above-cap cost requirements, but may not exceed the cap for large customers (> 10 million kWh per year) (N.M. Admin. Code § 17.9.572.11(C), 2011). Even when mandatory, however, a rate cap does not necessarily provide transparent customer protection. For example, in Colorado, the PUC has granted utilities waivers from the cost impact calculation for selected resources that are applied toward their RPS compliance obligation.

3.3. *Critique of cost caps*

Depending on how they are administered, cost caps may be administratively burdensome, non-transparent, and insufficiently protective of consumers. The annual process of determining the cap is time intensive. Moreover, as illustrated by New Mexico, without clear rules, the case-by-case process of determining caps may result in extremely skewed results for different entities. Whether the measures chosen are least-cost is also of grave concern to critics of cost caps. State PUCs likely vary with respect to how stringently they review the renewable measures set forth in utilities' annual compliance plans against a least-cost standard.

Most worrisome about the current approach to implementing caps is that the cap may be looking like no cap at all. Basing the cap on rates or even on revenue requirements allows costs already sunk on compliance to be imbedded in the denominator from which the cost cap derives. As the denominator increases, so does the cost to consumers. While such costs are often necessary to actually fund the aggressive goals of some states, administrators have expressed concern with the lack of transparency to consumers. While statutes may promise a rate increase no greater than a certain percent, the actual cumulative rate increases over many years may be much greater. For example, according to the Colorado PUC staff, after accounting for resources excluded from Colorado's rate impact calculation under a special waiver provision, renewable expenditures since its first compliance year in 2007 have actually far exceeded the two-percent rate cap. (Dalton, W.J., 2009, 2010). According to one estimate by New Mexico Public Regulation Commission Staff, New Mexico's rate increase may be closer to twenty percent over 2006 by 2020.

Another point of contention in determining the retail revenue requirement for purposes of calculating the rate impact of renewables is the inclusion of hypothetical costs in the "no-renewable" base case. For example, the Colorado PUC has required that utilities include both a carbon adder and a capacity credit in their system modeling to determine the rate impact. The carbon adder artificially inflates the apparent cost of the no-renewable revenue requirement while the capacity credit benefits the renewable resource. But neither the carbon cost nor the renewable capacity credit really exists at the present time. The impact of these hypothetical costs and benefits is to artificially diminish the apparent incremental cost of renewable compliance. This approach has been widely criticized in Colorado PUC proceedings by the parties most concerned with the cost impacts of renewable energy acquisitions while being supported by renewable energy advocates.

4. Surcharge on customers' bills

A relatively straight-forward way for utilities to recover RPS compliance costs is through a surcharge, also called a "rate rider" or adjuster, on consumers' bills. Riders allow utilities to directly incorporate into rates the fluctuating prices of traditional operating costs, such as fuel and labor costs, without undergoing multiple rate cases. Some commissions have allowed utilities to treat RPS compliance costs similarly and add cost recovery to customers' bill. States use various methods of calculating riders; for example, a flat system benefits charge or a usage-based adder. Overall, identifying the incremental costs of renewable resources via a bill surcharge—whether calculated on a flat-rate basis or per kWh—allows customers to see how much they are paying for RPS compliance.

A usage-based rider is generally set at a per kWh price. To cover the incremental cost of compliance with Arizona's Renewable Energy Standard, Arizona utilities may assess a monthly surcharge "substantially similar" to the one set forth in the sample tariff upon approval by the Arizona Corporation Commission ("ACC") (Ariz. Admin. Code R 14-2-1808, 2011). The Sample Tariff provides for a monthly surcharge assessed as $.004988 per kWh,[4] and utilities must substantiate their claims for this recovery in a proceeding based on the estimates of their annual implementation plans and the costs likely incurred. In order to protect customers, the rule appears to cap the overall surcharge at a flat rate of $1.05 for residential, $39.00 for small non-residential, and $117.00 for large non-residential. In 2008, most cooperative utilities did adopt the sample tariff's caps. Arizona's cap is not a ceiling, however. The state's largest utility proposed, and the ACC approved, a surcharge well-above the sample rate based on its calculated financing needs. Moreover, the state allows utilities to adjust the surcharge in their tariffs as needed. Additionally, the surcharge does not capture all costs of compliance as utilities may also drop large renewable construction projects into rate base.[5]

A variation of a usage (kWh)-based rider is one in which the rider is calculated as a percentage of a customer's total bill in dollars. Colorado has interpreted its two percent rate cap to allow its utilities to collect an additional two percent from each customer's monthly bill, itemized as the "Renewable Energy Standard Adjustment" or "RESA", to fund RPS compliance. In Colorado, utilities may bank unused portions of annual recovery toward future costs. However, this has led to criticism that the utilities are also incentivized to overspend the funds available under the RESA and earn their commission-authorized rate of return on funds advanced to the RESA, even if, as in the case of one major Colorado utility, the RPS compliance targets have been met or exceeded.[6]

4.1. *Critique of surcharges*

Overall, riders are more administratively efficient because they minimize the need for rate cases. North Carolina's rider was passed, in part, due to the lobbying efforts of utilities to avoid rate cases. And, in Michigan, which requires a rate case to establish a rider, few utilities have yet done so. With the exception of the banking allowed by Colorado, most states still require the utilities to go through some administrative process of truing up their incremental cost of compliance. The processes are much less cumbersome than rate cap true-ups, however. Another advantage of a surcharge as a cost limitation and recovery mechanism is that utilities have more certainty in their investment decisions. The surcharge caps set a clear benchmark. Utilities feel more assured that they can recover at least as much as they need, so long as they do not spend more than the statutory caps. One regulator has commented that this approach avoids imposing a "moving target" on utilities, as opposed to some of the cost caps for example.

The approach presents potential trade-offs for both customers, electricity providers, and the environment, as well. For customers, when costs are passed through with less scrutiny than in a ratemaking case, there is no guarantee that the surcharge is funding least-cost resources. Colorado's two-percent surcharge, passed directly through to customers, raises these concerns as well as whether the cap is actually protective. As described above, the RESA rider allows utilities to automatically recover the *maximum* allowable rate and bank recovery toward future costs, or even earn a return on advancing future funds. In Colorado as in many other RPS states, proponents have often argued that the RPS targets represent a floor, not a ceiling, and so utilities should be able to acquire renewables up to the limit of the cost cap. In contrast, RPS critics argue that the cap should represent an unambiguous limitation on the cost of meeting RPS targets, not a de facto minimum level of expenditures. Finally, whereas North Carolina and Michigan's surcharges are fixed and cannot be amended except by legislation, those states' RPSs may be compromised if the costs of renewables surpass what has been forecasted. North Carolina may reach its overall projected expenditures in just 5–6 years (N.C. Gen. Stat. § 62-133.8(i), 2011).

Arizona's hybrid approach attempts to remedy some of these issues by permitting utilities to apply capital expenditures to rate base and adjustable surcharges upon petition. However, the trade-off is less administrative efficiency and more of a moving target on actual costs. With so many off-ramps from the fixed tariff, customers' protection ultimately rests with the Commissioners' decisions to approve implementation plans.

5. Cap on utilities' total expenditures

One state that currently limits compliance costs to a specified dollar amount for its investor-owned utilities is California. California's approach is the so-called AMF Program (above-market price referent funds program) (Cal. Pub Util. Code § 399.15, 2011; Cal Pub. Res. Code §25740.5, 2011).The total AMFs available for the implementing period is equivalent to the amount of funds that would have been available if utilities were still required to charge a Public Goods Charge to its customers through 2012: over $770 million. Public Utilities Code § 399.15 provides that each of the state's major investor-owned utilities is allocated a specific amount of this total from which it will be eligible for cost recovery of above-market contracts in its rates subject to certain criteria.[7] Contracts must meet specific eligibility criteria related, in part, to cost-competitiveness and longevity (Cal. SB 1036, 2007; Cal. Resolution E-4199, 16, 2009). The cap is voluntary in that a utility is relieved of procuring any other above-market cost contracts in compliance with the RPS once it reaches the cap, but may petition the California Public Utility Commission ("CPUC") to approve above-cap cost recovery. The CPUC may also require a utility to procure additional renewables after the utility has reached the cap. In this regime, all contracts eligible for AMF-funds, and the entire contract price, must be counted against the cap.

The CPUC must determine whether a contract is eligible for AMF-funds by considering the difference between a project's levelized contract price (per MWh) and a specific market price referent ("MPR"). Annually, the CPUC adopts by resolution MPRs based on the presumptive cost of electricity from a non-renewable energy source, including the long-term market price of electricity for fixed contracts, the long-term fuel and operating costs for comparable new generating facilities, and the value of the electricity's characteristics such as peaking or baseload. Thus, the positive difference between a contract price and the MPR counts toward the electrical corporations' cost limitation. The CPUC does not review unbundled RECs purchases—permitted for compliance since 2010—under the AMF program and so their costs do not count against the utilities' cap (Cal. Pub Util. Code §

[4] This is 5.7 times the amount initially allowed.

[5] For example, Arizona Public Service Company is seeking to put its $500 million new 100-MW PV system into rate base. Interview with Staff at Arizona Corporation Commission (Dec. 3, 2010); Docket E-0 1345A- 10-0262, APS Application (July 2010).

[6] In recently issued decisions C11-1079 and C11-1080, the Colorado PUC has also expressed concern with the "deviations between budgeted RESA expenditures and actual charges against the RESA account (Colorado Public Utilities Commission, 2011a,b)."

[7] BVES $ 328,376; PG&E $ 381,969,452; SDG&E $ 69,028,864; SCE $ 322,107,744; Total $ 773,434,436. Resolution E-4199, 16.

399.15, 2011). For price protection, the CPUC has set a de facto REC price cap of $50 and limits utilities to meeting 25% of their compliance obligations with tradable RECs.

5.1. *Critique of California's cap*

The AMF program constitutes a significant change from the state's former cost curtailment program. The California legislature amended the former cost curtailment process of using Supplemental Energy Payments (SEPs) to cover above-market costs in 2007 in order to streamline the process. Formerly, utilities collected a Public Good Charge ("PCG") via customers' bills, part of which was transferred to the New Renewables Resource Account (NRRA) in the Renewable Resource Trust Fund to fund SEPs. The California Energy Commission administered these funds for the above-market costs of electric corporations. There was no individual utility cap. Once the funds were fully allocated, utilities were required to procure in fulfillment of the RPS only those renewable resources that were at or below market price. In contrast, the new method utilizes rate increases, not the PCG, and requires the CPUC's approval of both the above-market costs and the procurement contracts in order for cost recovery of AMFs that fall within each utility's overall cap. The CPUC has identified several added benefits of the new methodology: (1) to further promote the goals of RPS program (in-state, long-term, stable), (2) to support viable least-cost best-fit renewable energy projects, (3) to allocate AMFs transparently, and (4) to result in simpler administration of AMFs (Resolution E-4199, 10, 2009).

On the other hand, California's current approach presents two disadvantages for utilities. First, the process is administratively burdensome. A utility must seek agency approval for every contract. Second, it is unclear whether the specified caps will allow utilities to meet California's aggressive RPS targets. Once a utility reaches its cap, the utility would be required under this approach to seek cost recovery to procure additional resources. Utilities therefore may not be inclined to petition to exceed the cap in order to meet the RPS. It is worth noting that the CPUC may have alleviated this concern when it permitted unbundled RECs for compliance.

6. Alternative compliance payments

6.1. *Alternative compliance payment as de facto cap*

Many restructured states utilize an alternative compliance payment ("ACP"), either alone or in conjunction with other cost curtailment mechanisms. The ACP enables electric distributors and retail providers to pay a specified amount into a central fund in lieu of procuring renewable energy or buying RECs. For those states in which the ACP is recoverable,[8] the ACP serves as a de facto cap in that it sets the price ceiling for the cost of compliance. Where ACPs are required, the ACP price constitutes the cost of RPS compliance. The alternative electricity suppliers in Illinois (distinct from the vertically-integrated utilities discussed above) must fulfill half of their RPS requirements through ACPs, for example (Ill. Comp. Stat. 220 ILCS 5/16-115D, 2011). In states where the ACP is optional, rational entities will tend to opt for other means of compliance (RECs, PPAs, etc.) up to point at which those costs are equivalent to or higher than the ACP. Where prices of procurement surpass the ACP price, without additional incentives or obligations, utilities will opt for the ACP which sets the ceiling price. Whether ACPs are recoverable, how they are priced, and other nuances contribute to the efficacy of this mechanism as a cost cap. This section discusses some of the states that rely on ACPs for RPS cost control and their overarching issues.

States differ with respect to the burden utilities bear for obtaining approval of ACP costs from the state agencies. In Maine, Massachusetts, New Hampshire, New Jersey, and Rhode Island, utilities may recover any cost of ACPs deemed reasonable and prudent by the state commissions (35-A Maine Rev. Stat. § 3210, 2011 ; Mass. Gen. Law ch. 25A, § 11F, 2011; N.H. Rev. Stat. § 362-F, 2011; N.J. Stat. § 48:3-87, 2011; R.I. Gen. Laws § 39-26-1 et seq., 2011). In contrast, the ACP costs incurred by providers in Delaware, Oregon, Maryland, Pennsylvania, and D.C. may only be passed on to consumers if they demonstrate in addition to general reasonableness (1) the ACP is the least cost measure to ratepayers compared to the purchase of renewable energy credits to comply with the RPS; or (2) there are insufficient renewable energy credits available for the electric supplier to comply with the RPS causing the Commission to find a force majeure (26 Del. Code § 358, 2011; Md. Pub. Util. Co. Code §§ 7-701 et seq, 2011; Penn. Stat., 73 P.S. § 1648.3, 2011; Penn. Admin. Code, 52 PA ADC § 75.67, 2011; D.C. Code § 34-1431 et seq, 2011; Or. Rev. Stat. §§ 469A.100 et seq, 2011). Maryland also allows cost recovery if (3) a wholesale electricity supplier defaults or otherwise fails to deliver RECs under a commission-approved supply contract (Md Public Util Comp § 7-706, 2011). Additionally, whereas cost recovery of ACPs generally occurs as a specific surcharge on customers' bills, at least one state allows utilities to petition the state agency for inclusion of ACPs in rate base. Prudence review by a state commission subjects a utility's ACPs to the commission's further scrutiny. Oregon has expressly prohibited ACPs from being recovered in rate base (Or. Rev. Stat. §§ 469A.100 et seq, 2011).

ACP prices also vary. The total ACP is calculated by multiplying the alternative compliance payment rate by the number of deficient kilowatt-hours. The ACP rate may be established by statute or by state regulators. For example in New Jersey, the ACP is $50 per MWh, while the solar ACP drops from over $700 per MWh to about $600 per MWh by 2016 (N.J. Admin. Code § § 14:8-1.1 et seq, 2011). State legislatures may also establish guidelines for ACPs via statute. Although Texas does not currently have an ACP, the state legislature has expressly authorized its commission to establish an ACP which, for compliance that could otherwise be satisfied with a REC from wind, may not be less than $2.50 per credit or greater than $20 per credit (Texas Util Code § 39.904(o)). Presently Texas has only a penalty provision that itself serves as a de facto cap by penalizing entities $50 for each MWh a utility falls short of compliance with the RPS targets. Finally, Illinois's AC payments are derived from the state's statutory rate cap. The state Power Agency sets the ACP price for each service area equal to "the maximum allowable annual estimated average net increase" calculated in the annual procurement planning of the state's large utilities for that service area (PUCT Substantive Rule 25.173(p) (2011).

Some states may "freeze" increasing RPS targets if costs of compliance exceed a specific indicator. Maine uses its ACP as such an indicator. The Maine PUC may suspend annual increases in the RPS standard if ACPs are used to achieve more than 50% of the compliance obligation of utilities. Alternatively, the Maine PUC may also suspend the RPS if it determines that meeting the target is overly burdensome to customers.

6.2. *ACPs generally fund public benefits funds with several exceptions*

ACPs are extremely important in reducing the overall cost impacts to consumers of increasing renewable generation

[8] Where not recoverable, as in Ohio (discussed above), the ACP merely serves as a penalty for non-compliance.

because they often help fund a central public benefits fund that supports renewable development in the state. States with PBFs include: California, Connecticut, D.C., Delaware, Illinois, Maine, Massachusetts, Minnesota, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, and Wisconsin.

PBFs are viewed as a complement to, not an integral part of, most state RPSs with the exception of New York. In New York, the New York State Energy Research and Development Authority ("NYSERDA") administers the state's 30x15 RPS with funds collected from a non-bypassable volumetric "System Benefits/ RPS Charge" on major utilities' customers' bills (NY PSC Order Case 03-E-0188, 2004; http://www.nyserda.org/rps/index.asp). The RPS portion of this charge was approximately $2.87 in 2007 for a typical residential customer and $30.24 for a typical non-residential customer. NYSERDA solicits renewable projects with these funds, which have culminated to date in 38 facilities under contract to provide a combined 4,276,140 MWh of renewable energy per year, from approximately 1,532 MW of new renewable capacity.

PBFs in most other states are managed by a neutral entity that solicits projects based on specific criteria. Many state PBFs are managed by a governmental office. Others are managed by corporations or non-profit organizations created specifically to manage the fund (e.g. Oregon, Rhode Island, and Connecticut). At least one state, Arizona, allows utilities to manage renewable energy funds (Az. Corp. Comm. Dec. No. 69663, 86 2007). With respect to funding, a few states fund their PBFs for renewables from something altogether separate from ACPs, such as a public purpose charge (Oregon, New Jersey) or leftover savings from other projects (Michigan). Some states also keep separate funds collected for specific set-asides. For example, Maryland and Massachusetts require that ACPs for the solar obligation only be used to support new solar resources in the state (Md. Code § 9-20B-05, 2011 ; Code Mass. Reg., 225 CMR 14.07, 2011).

6.3. *Critique of ACPs and public benefits funds*

Where they exist, ACPs become the ultimate price ceiling on compliance for utilities and their consumers. In this way, they are extremely important for consumer protection, particularly where the costs of RECs or renewables are unknown or prohibitively high. At the same time, because ACPs set the ceiling, the price must be properly set or else risk the integrity of the RPS. If the ACP price is too low, electricity providers as rational business entities may be encouraged to choose the alternative and not procure renewables. If too high, on the other hand, or if not-recoverable, the ACP merely becomes a penalty and not a safety valve. In states where cost recovery of compliance is a near foregone conclusion, however, the ACP price may do nothing to affect utilities' procurement decisions even if it means higher prices for consumers. In addition to price, the efficacy of the ACP as a cost limitation mechanism also rests on how effectively ACP funds are used to procure renewable resources. If ACPs are not used, or not used efficiently, to fund renewable projects, they cannot be considered a cost curtailment mechanism. By not efficiently funding renewable projects today, faulty ACPs either inhibit the ultimate goals of the RPS or raise the costs of eventually meeting those goals by drawing out the process of compliance.

Different issues arise with PBFs that are not funded by ACPs. A hard-line surcharge such as that of New York funds renewables with more certainty than other approaches, but does not necessarily ensure that the state reaches its targets and at the lowest price. The government administrator likely does a better job on average than a utility considering least-cost alternatives, however.

7. Cap on contract price

Two states, Montana and Hawaii, utilize a cost limitation on a per-contract basis. In both states, utilities may petition the state agencies in the event that they are unable to meet their RPS obligations and request for a waiver if contracts for procuring generation or renewable energy credits were above-market price for other available resources. In Montana, a competitive retail provider is not obligated to take electricity from an eligible renewable resource unless the total cost of electricity from that eligible resource, including the associated cost of ancillary services necessary to manage the transmission grid and firm the resource, is less than or equal to bids in the competitive bidding process from other electricity suppliers for the equivalent quantity of power over the equivalent contract term (Mt. Code Admin. 69-3-2007, 2011; Mt. Admin. Rules 38.5.8301(4)). In contrast, a regulated public utility in Montana is not obligated to take electricity from an eligible renewable resource unless the cost per kilowatt-hour of the generation does not exceed by more than 15% the cost of power from other alternate available generating resources. In Hawaii, utilities may petition the Public Utilities Commission for a waiver of a penalty for failure to meet the RPS (Haw. Rev. Stat. Ann. § § 269-92, 2011). The Commission may grant such a waiver if it determines a utility is unable to meet the RPS "due to reasons beyond the reasonable control of an electric utility" including, in part, inability to acquire sufficient cost effective renewable electrical energy (Haw. Rev. Stat. Ann. § § 269-92, 2011). "Cost-effective" means the ability to produce or purchase electric energy or firm capacity, or both, from renewable energy resources at or below avoided costs consistent with the methodology set by the PUC.

7.1. *Critique of cap on individual contracts*

This mechanism is likely cost-protective of consumers, holding the cost of compliance close to the cost of alternate sources (i.e. gas). Because the cap is generally enforced by state regulatory bodies, however, this approach may create an administrative hurdle that could prevent utilities from acquiring the most cost effective resource. Moreover, the ultimate discretion lies with the agency to determine whether the resources are really least-cost. As discussed more below, such discretion leads to uncertainty for utilities, investors, project developers, customers, and the state. On the other hand, if utilities utilize this limitation to its potential, the mechanism could severely reduce the integrity of the RPS as the price of renewables may often be higher than alternative resources.

8. Ad hoc agency discretion to curtail costs

Some states have not relied on specific cost curtailment mechanisms but instead look to the state commissions to limit excessive costs to consumers by exercising their traditional duty to ensure just and reasonable rates. Depending on whether the state is restructured or not, and on its legislative mandates, states without a cap often rely on their statutory obligation to ensure just and reasonable rates in rate cases, the review of rate riders, and the approval of individual contracts. The states without a defined cap include Minnesota, Wisconsin, Iowa, and Nevada. Additionally, almost all states embody state regulatory agencies with sufficient discretion to waive certain compliance provisions where concerns of cost and fairness are raised.

8.1. *Just and reasonable review in ratemaking*

In Minnesota, pursuant to the cost-of-service model, utilities may recover any prudently and reasonably incurred costs if approved by the Minnesota Public Utilities Commission. There are no specified caps on rate increases or utilities' budgets for implementing the RPS. The legislature granted the PUC the authority, however, to grant modifications or waivers of utilities' compliance obligations upon request if the commission find it is "in the public interest" to do so (Minn. Stat. § 216B.1691, Subd. 2b, 2011). The enacting legislation clarifies that the PUC must consider, among other factors, "the impact of implementing the standard on its customers' utility costs, including the economic and competitive pressure on the utility's customer." With regard to a request for a waiver based on costs to customers, the PUC may only grant a waiver "if it finds implementation would cause significant rate impact." There are no additional rules or regulations that clarify exactly what constitutes a "significant rate impact." To date, all 118 electric providers in the state have complied with the law every year since it was revised in 2005, and not one has requested a compliance deadline extension. Therefore, because no utilities have yet come forward with a petition for a waiver, Staff at the PUC was unable to discuss the process further. Decisions would likely be made on a case by case basis unless the legislature amends the statute in the coming years.

Iowa's Alternative Energy Law ("AEL"), which requires the state's two vertically-integrated utilities either to own a certain amount of renewable energy in the state or to procure long-term contracts for such sources in the utilities' service area, applies only the traditional just and reasonable cost standard to renewable procurement (Iowa Code § 476.43, 2009). For new facilities, the state's Utility Board may adopt individual utility or uniform statewide facility rates "sufficient to stimulate the development of alternative energy production" that are deemed reasonable in light of economic and other factors. Power purchased by contracts must be competitively priced, "based on the electric utility's current purchased power costs." The AEL targets are sufficiently conservation that they likely do not require significant cost curtailment.

8.2. *Contract review*

Pursuant to the legislation enacting Nevada's Energy Portfolio Standard, the Public Utility Commission of Nevada ("PUCN") must review and approve every new contract for renewable energy procurement or energy efficiency under a *modified* just and reasonable standard (Nev. Admin. Code § 704.8885, 2011). The modified standard requires the PUCN to consider factors such as price reasonableness, characteristics of the resource, fitness and viability of the project, and the terms and conditions of the contract. With respect to price reasonableness, the PUCN must explicitly consider: (1) consistency with long-term planning, (2) reasonableness of price indexing; (3) environmental costs and reductions; (4) net economic impact and environmental costs and benefits; (5) economic benefits to the state; (6) diversity of energy resources; (7) transmission costs and benefits; and (8) the utility's long-term avoided costs. The review of whether specific contracts are just and reasonable may impact whether the utility may be exempted from meeting all of its compliance obligations. A utility may petition the PUCN for exemption from an administrative fine or other action resulting from its failure to meet the RPS and must show that there was not a sufficient supply of contracts with just and reasonable terms available to the utility. This review is likely similar to that in Hawaii and Montana but less constrained as the PUCN appears to have greater discretion to consider factors besides the costs of alternative sources.

8.3. *Freeze provisions*

Some states have statutory or regulatory freeze provisions that allow agencies to freeze incremental increases of RPS targets when compliance costs reach specific cost caps. Some states also give state agencies more discretion to freeze the RPS if costs become excessive. For example, New Hampshire's statute states that the PUC, after notice and hearing, may accelerate or delay by up to one year, any given year's incremental increase in class I or II renewable requirements for "good cause". PUC rules state that the term "good cause" means that the acceleration or delay would reasonably be expected to: (1) increase investment in renewable energy generation in New Hampshire; or (2) mitigate cost increases to retail electric rates for New Hampshire customers without materially hindering the development of renewable resources.

8.4. *Waivers*

In addition to cost limitations, most states also expressly provide state agencies the discretion to grant entities waivers. Some provisions appear broad enough to allow for waivers due to cost impacts to consumers. In Ohio, in addition to the net revenue requirement rate cap and an alternative compliance payment, the Commission may identify the existence of force majeure conditions and grant waivers (Ohio Admin. Code § 4901:1-40 et seq, 2011). The North Carolina PUC may modify or delay the RPS provisions if the PUC determines that it is "in the public interest" (N.C. Gen. Stat. § 62-133.8(i), 2011). In New Mexico, utilities may seek a waiver for "good cause" (N.M. Rule 14-2-1816, 2011). Waivers may be from the RPS compliance targets or, as in Colorado, from the rate impact provisions themselves (Colorado PUC, 2007).

8.5. *Critique of agency discretion*

Utilizing traditional commission review to set the cost of RPS compliance on one hand makes a lot of sense. Utilities and commissions follow traditional administrative processes to work through issues that are at the same time novel and familiar. In doing so, they also hew to the regulatory compact. Utilities likely can recover costs they can reasonably justify. Moreover, there is no seemingly arbitrary point (a cap) at which compliance obligations stop short of the RPS targets. Further, customers are not lured into a false sense of security from a non-transparent cap.

On the other hand, traditional agency review creates its own risks and an enormous amount of uncertainty. In addition to a significant administrative burden, there is a risk that case-by-case decisions to approve utilities' costs of compliance may be arbitrary, politically motivated, or unfair, may favor one stakeholder group over another, and may prioritize utilities' return on investment over the costs to consumers. The more discretion that is left to a state commission, a body that is subject to political influence or other motivations, the greater the level of uncertainty to electricity providers and consumers alike.

9. Conclusion

In the face of the uncertain and likely increasing costs of implementing state RPSs, lawmakers, regulators, and interested parties must walk a fine line between consumer protection and maintaining the integrity of the policies. The range of mechanisms designed to mitigate the costs of RPS compliance embodies these competing concerns. At first glance, a hard-line cost cap would appear to protect consumers from excessive price increases due to increasing renewable energy penetration. A closer look suggests that many states with a cap actually utilize a hybrid incremental cost cap that may compromise consumer protection and transparency in order to satisfy aspirational renewable targets and utilities' needs. Alternatively, traditional agency discretion in rate regulation leaves state commissioners with the job of balancing dueling considerations of consumer protection and RPS integrity. Although an ample reserve of discretion must be left to state commissions to allow for flexibility in this extremely complicated area of renewable energy policy, there must be safeguards to ensure waivers are limited and granted in an even-handed fashion. Additionally, implementation of the various mechanisms described above also raises issues of utilities' ability to recover, transparency, and administrative burdens.

Although the costs of implementing state RPSs are uncertain, it is clear that the transition to cleaner energy will not come free. While utilities and regulators must work to mitigate cost increases shouldered by consumers, they should not hide cost increases through sunk costs, complex administrative proceedings, convoluted opaque rate cap methodologies, or misnomers. Given how intricately different state electricity markets are structured, we do not presume to prescribe only one preferred cost limitation approach that will work in all cases. Rather, this preliminary survey suggests that the most important factors in implementing any effective and credible mechanism to curtail costs are clarity of the rule, consistency in application, and, above all, transparency for customers.

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Executive Summary

More than half of U.S. states have renewable portfolio standards (RPS) in place and have collectively deployed approximately 46,000 MW of new renewable energy capacity through year-end 2012. Most of these policies have five or more years of implementation experience, enabling an assessment of their costs and benefits. Understanding RPS benefits and costs is essential for policymakers evaluating existing RPS policies, assessing the need for modifications, and considering new policies.

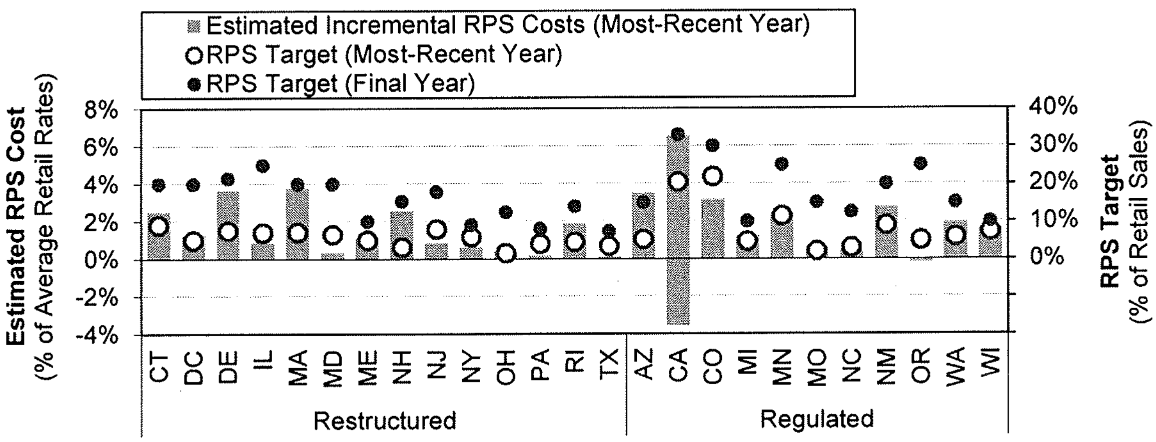
This report surveys and summarizes existing state-level RPS cost and benefit estimates and examines the various methods used to calculate such estimates. The report relies largely upon data or results reported directly by electric utilities and state regulators. As such, the estimated costs and benefits itemized in this document do not result from the application of a standardized approach or the use of a consistent set of underlying assumptions. Because the reported values may differ from those derived through a more consistent analytical treatment, we do not provide an aggregate national estimate of RPS costs and benefits, nor do we attempt to quantify net RPS benefits at national or state levels.

The report summarizes state-level RPS costs to date and considers how those costs may evolve going forward given scheduled increases in RPS targets and cost containment mechanisms incorporated into existing policies. The report also summarizes RPS benefits estimates, based on published studies for individual states, and discusses key methodological considerations. These estimates, for example, of the social value of carbon emissions reduction and the human health impacts of reduced air emissions, are based on a variety of methodologies and assumptions. In comparison to the summary of estimated RPS costs, the summary of RPS benefits is more limited, as relatively few states have undertaken detailed benefits estimates. Further, for those states that have estimated RPS benefits, most assess only a limited number of impact types; as a consequence, some types of benefits are not reflected in this report.

RPS Costs

Our analysis focuses specifically on the *incremental* cost of meeting RPS targets, i.e., the cost above and beyond what would have been incurred absent the RPS, over the 2010-2012 period. For states with restructured markets, we derive RPS compliance costs based on the cost of renewable energy certificates (RECs) and alternative compliance payments (ACPs). For traditionally regulated states, we instead rely upon RPS cost estimates reported directly by utilities or regulators within annual compliance reports or other regulatory filings (not prospective studies), and translate those estimates into a set of common metrics for comparison. The methods used by utilities and regulators to estimate incremental compliance costs vary considerably from state to state, in some cases reflecting statutory or regulatory requirements, and a number of states are currently engaged in processes to refine and standardize their approaches to RPS cost calculation.

Importantly, the estimated RPS costs summarized within this report must be considered in light of what the underlying data represent and the limitations therein. First and foremost, the comparisons across states are imperfect, given the varying methods and assumptions used (especially among regulated states). Second, the data presented most closely correspond to the costs borne by utilities or other load serving entities; they do not represent net costs to society, nor do they necessarily represent the costs ultimately borne by ratepayers, such as in cases where ACPs or financial penalties are not passed through to rates or differences in the timing of when costs are incurred and recovered in rates. Third, depending upon the state and particular methodology used, the cost data may omit certain costs incurred by utilities (e.g., integration costs), as well as possible benefits. Other analysis has examined integration costs; for example, a number of U.S.-focused studies have found wind integration costs to be less than $5/MWh (Wiser and Bolinger 2013). Finally, the use of REC prices to compute RPS compliance costs in restructured markets is limited in some cases by a lack of REC price transparency and incomplete data on long-term contracts. In addition, REC prices can be quite volatile, with large swings from year to year, depending upon whether a given state or region is in surplus or deficit relative to its RPS obligations. As such, the calculated RPS compliance costs for restructured markets may not correspond well to trends in the underlying cost of renewable electricity.



** For most states shown, the most-recent year RPS cost and target data are for 2012; exceptions are CA (2011), MN (2010), and WI (2010). MA does not have single terminal year for its RPS; the final-year target shown is based on 2020. For CA, high and low cost estimates are shown, reflecting the alternate methodologies employed by the CPUC and utilities. Excluded from the chart are those states without available data on historical incremental RPS costs (KS, HI, IA, MT, NV). The values shown for RPS targets exclude any secondary RPS tiers (e.g., for pre-existing resources). For most regulated states, RPS targets shown for the most-recent historical year represent actual RPS procurement percentages in those years, but for MO and OR represent REC retirements (for consistency with the cost data).*

Figure ES-1. Estimated incremental RPS costs compared to recent and future RPS targets

In light of what the underlying data represent and the limitations therein, the following are key findings with respect to RPS costs.

- Over the 2010-2012 period, average estimated incremental RPS compliance costs in the United States were equivalent to 0.9% of retail electricity rates when calculated as a weighted-average (based on revenues from retail electricity sales in each RPS state) or 1.2% when calculated as a simple average, although substantial variation exists around the averages, both from year-to-year and across states. Focusing on the most recent historical year available, estimated incremental RPS compliance costs were less than 2% of average retail rates for the large majority of states (see Figure ES-1).
- Among restructured markets, estimated incremental compliance costs ranged from 0.1% to 3.8% of retail rates. Expressed in terms of the cost per unit of renewable energy required, estimated incremental RPS compliance costs in these states ranged from $2-$48/MWh.

Variation among those states reflects differences in RPS target levels, REC pricing, the composition of RPS resource tiers, and other factors.

- Among traditionally regulated states (excluding California), estimated incremental compliance costs varied from -0.2% (i.e., a net savings) to 3.5% of average retail rates. Variation among these states partly reflects differences in RPS procurement levels. In addition, relatively high estimated costs for a number of states are associated with the presence of distributed generation (DG) set-asides, for which compliance costs tend to be "front-loaded." The estimated incremental costs of meeting general RPS obligations (i.e., excluding DG or solar set-asides) ranged from -$4 to $44/MWh of renewable energy procured.
- Methodological differences contribute to observed variations in these compliance cost estimates, especially among regulated states. For example, in California, two different methodologies yield derived incremental compliance cost estimates ranging from a net savings equal to 3.6% of retail rates to a net cost of 6.5%, as shown in Figure ES-1.
- Utilities in eight states assess surcharges on customer bills to recoup RPS compliance costs. These utility-reported surcharges, which represent the costs borne directly by customers, ranged in 2012 from about $0.50/month to $4.00/month for average residential customers, and on a statewide average basis, equate to roughly 0.5% to 4% of average retail electricity rates. These customer surcharges may differ from the estimated compliance costs borne by the utility for a variety of reasons, such as differences in the timing or type of costs that can be passed through to customers.
- Estimated incremental RPS compliance costs over the historical period of our analysis reflect the RPS targets applicable during those years (the open circles in Figure ES-1). Under current policies, RPS targets are scheduled to increase significantly, eventually reaching levels represented by the closed circles. Whether and the extent to which incremental RPS costs rise in tandem depends on many factors: renewable energy technology costs trends, natural gas prices, federal tax incentives, and environmental regulations, among others.
- Future RPS compliance costs are limited by cost containment mechanisms built into most RPS policies. Among those states relying principally upon an ACP mechanism for cost containment, RPS costs are effectively capped at roughly 6-9% of average retail rates in most cases. Cost caps in most other states are considerably more stringent, often limiting compliance costs to 1-4% of average retail rates. Compliance costs in several of those states have already reached or are approaching the respective caps.

RPS Benefits

Policymakers often consider RPS costs within the context of broader social benefits beyond any direct cost savings that may accrue to utilities. Potential benefits of RPS policies include reduced emissions, water savings, fuel diversity, electricity price stability, and economic development. States have most commonly attempted to quantitatively assess avoided emissions and associated human health benefits, economic development impacts, and savings from reductions in wholesale electricity prices. In many cases, these assessments are required by the legislature or public utilities commission (PUC), filed as part of an integrated resource plan (IRP) docket, and prepared for regulatory commissions, energy boards, or public benefit corporations. In this work, we focused on analyses conducted as part of state-level RPS evaluations, but did not review the broader literature on renewable energy benefits in general. While we attempted to conduct a thorough literature review, we have likely omitted some analyses; however, this review provides an indication of the types of benefits analyses that have been conducted and the range of benefits found.

Key findings include:

- A relatively small number of RPS benefits estimates have been developed and methodologies vary considerably, which limits the ability to make comparisons and bounds the range of impacts. We identified studies for eight states that assessed the societal benefits or broader impacts of RPS policies based on our review of literature. Most studies of benefits or impacts are prospective in nature, assessing not only the current RPS impacts, but also examining future impacts, in contrast to the cost estimates previously discussed that are retrospective. Some types of benefits, such as avoided emissions, can accrue for the lifetime of the renewable energy plant, while costs are incurred typically over a shorter period.
- We identified six studies that attempted to quantify the emissions or human health benefits of state RPS policies. Most used modeling approaches to assess scenarios with and without renewable energy and some estimated the dollar values associated with emissions reductions. In some cases, emissions benefits may be captured in estimates of net incremental costs, such as if allowance prices are already embedded in wholesale electricity prices. Estimates of benefits ranged from roughly tens to hundreds of millions of dollars on an annual basis depending on the state and scenario. These estimates translate to approximately \$4-23/MWh of renewable generation, depending on the study and the cost value assumed for CO_2.
- Similarly, we identified six studies that attempted to quantify economic impacts of an RPS. Two used economic modeling approaches while the others used input-output models or simplified case study approaches. Often input-output models or simplified approaches estimate gross jobs, which do not account for shifts in employment that may occur, as opposed to new net jobs. A number of the studies examined economic development benefits annually or over the lifespan of the renewable energy projects, with benefits on the order of \$1-\$6 billion, or \$22-30/MWh of renewable generation.
- Six states estimated wholesale market price reductions that resulted from an RPS (i.e., the reduction in market clearing prices resulting from an increase in the supply of low marginal-cost renewable resources), typically using electric system modeling or applying estimates from other modeling efforts. The studies generally found wholesale price reductions of about \$1/MWh or less within specific markets (total generation), or price suppression benefits of \$2-\$50/MWh of renewable energy generation.
- Comparison of costs to benefits is challenging, even when they are reported in the same study, given that some incremental cost calculations may already take into account specific benefits, analysis time periods may differ, benefits assessments may address only particular types of benefits, and other factors. Most states for which we have identified benefits estimates did not conduct direct comparisons.

In the future, additional efforts could be undertaken to comprehensively assess the costs and benefits of state RPS policies by comparing costs and benefits directly, using similar methodologies and level of rigor. Further, additional work could be done to standardize incremental cost calculations within and among states provided that such cost calculations are often required by RPS statutes. Efforts in a few states are underway to address standardization of incremental cost calculations; states that have not examined standardization may see the issue arise in the future and be able to learn from the processes and outcomes of existing state standardization efforts.

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1 Introduction

Renewable portfolio standards (RPS) have been widely adopted by states and have reached moderate-to-advanced stages of implementation, so that there is now sufficient experience to examine implementation costs and benefits. RPS policies call for electricity providers to acquire specific amounts of renewable energy generation over time, often as a percentage of overall electricity supplied. These policies have been a significant driver of development of new renewable capacity additions in the United States, with roughly 46 GW or two-thirds of all non-hydroelectric renewable capacity additions since 1998 occurring in states with active or impending RPS targets.[1] Today, RPS policies are established in 29 states plus Washington D.C. and Puerto Rico.[2] RPS policies in 22 states have been in place for five or more years, and RPS polices in five states have been in place for more than a decade; this degree of implementation experience has led to cost and benefit assessments by utilities, states, and others.

Understanding the costs and benefits of RPS policies can be important for program evaluation, understanding policy effectiveness, consideration of new policies, and assessing potential modifications to existing RPS policies. In recent years, there has been significant legislative activity to modify RPS targets (CNEE 2012), and information on RPS implementation costs across states can be particularly important for informing legislative decisions.

Information about RPS costs is also often needed to support other regulatory and legislative processes. RPS costs, in some cases, are recovered through a dedicated surcharge or tariff rider on customer bills that is adjusted regularly and approved by the public utilities commission (PUC). In these instances, utilities must estimate the costs when requesting adjustments to the surcharge. States may also conduct occasional evaluations of their RPS programs, which may be required by statute. Such evaluations are often much broader in scope than the aforementioned administrative processes, and may include analyses of benefits, such as economic development and environmental impacts.

Many states have cost containment mechanisms in place that limit RPS compliance costs and the associated impact on ratepayers (Stockmayer et al. 2012; CPI 2012). For example, several states have developed rules precluding the cost of RPS compliance from exceeding 2-4% of retail electricity rates. As a result of these provisions, utilities and PUCs must routinely evaluate RPS program costs—typically within the context of annual compliance filings or reports to the legislature—to ensure that the compliance costs do not exceed the cost caps.

In implementing RPS cost caps, surcharges, and program evaluations, states have faced methodological issues associated with determining compliance costs. In some cases, methods for calculating such costs may be briefly specified in statute or in implementing rules by the PUC. Even in cases where the broad methods are defined, there can be significant variability in utility

[1] The 46 GW figure is intended as a rough proxy for the impact of state RPS programs on renewable energy development to date, and was derived by simply considering the date and location of renewable energy capacity additions. For the purpose of this tabulation, renewable additions are counted if and only if they are located in a state with an RPS policy and commercial operation began no more than one year before the first year of RPS compliance obligations in that state.

[2] For additional detail, see the DSIRE database: http://www.dsireusa.org/rpsdata/index.cfm.

calculations. As a result, a number of states (e.g., New Mexico, Minnesota, Washington) have recently conducted or are currently engaged in regulatory proceedings to develop consistent RPS cost calculation methods across utilities. Some of the key challenges include assessing the incremental or above-market costs of acquiring renewable generation rather than conventional generation sources and the timeframe of the cost calculation.

While most states or utilities have estimated or collected data on compliance costs, only a few have assessed benefits quantitatively. Benefits of RPS policies can include environmental benefits, such as avoided air pollutant emissions, human health effects, and reduced water consumption, as well as fuel diversity, economic development, electricity price stability, and others. Methods used to assess benefits are substantially different than for estimating costs, and these are covered separately in this report.

This analysis adds to a relatively small, but varied, literature analyzing RPS costs across states. At the national level, cost impacts of a proposed federal RPS have been studied with the use of modeling tools (Bird et al. 2011, Fischer 2010, and Wiser and Bolinger 2007). At the state level, Morey and Kirsch (2013) use regression analysis to examine the impact of various policies, including an RPS, on electricity rates, using historical data. Chen et al. (2007) examined prospective, rather than retrospective, RPS studies, the majority of which were funded by nongovernmental organizations. Of the studies reviewed by Chen et al., 21 of 30 projected a retail rate increase of less than or equal to one percent in the RPS peak target year, while nine studies predict rate impacts above 1% and two of those studies predict rate impacts of more than 5%.

While prospective RPS studies have been conducted in many cases, in some instances at the request of state legislatures, this analysis does not utilize forward looking cost studies, but rather focuses on estimates of actual incurred costs. The approach used in our analysis focuses on estimated incurred costs so as to better determine rate changes that are attributable to RPS implementation costs rather than other factors that can influence rates.

This paper examines estimated costs and benefits from RPS implementation to date and the expected costs if they continue to evolve over time to their end target. In general, the information presented in this report can be important for policymakers and other stakeholders to understand how state RPS implementation costs and benefits compare as they evaluate existing RPS policies and consider revisions going forward. The focus of this report is on estimated costs to load serving entities subject to RPS targets; we do not focus on broader societal costs (such as federal tax subsidies). Data for this report are obtained primarily from PUC compliance filings, program evaluations conducted or authorized by state commissions, and other state-commissioned studies. Section 2 assesses current methods used to evaluate RPS costs and discusses the issues and challenges associated with various approaches. Section 3 assesses estimated RPS cost data for states where information is available, discussing underlying reasons for differences across states and the impacts of policy design (for example, the presence of solar carve-outs). The potential to reach cost caps in coming years is also examined. Section 4 reviews quantitative benefits information, focusing on estimates of broader societal benefits prepared for formal evaluations of state-level RPS policies, often at the request of legislatures.

2 Methods of Determining Cost Impact

Section 2 and Section 3 of this report survey various methods used to estimate the costs of renewable portfolio standards and summarize estimates of state RPS costs to date, relying largely upon data or results reported directly by electric utilities and state regulators. As such, the estimated costs itemized in this document do not result from the application of a standardized approach or the use of a consistent set of underlying assumptions.

Costs examined by utilities, states, and regulators may be defined as either "gross costs" or "incremental costs." Gross costs consist of the total cost of procuring renewables to meet the RPS, while incremental costs (also referred to as "net" or "above market" costs) examine the difference between gross costs and the costs that would have been borne absent the RPS. "Incremental" is sometimes defined in different ways; here we refer to incremental cost as the additional cost of renewable electricity above and beyond what would have been incurred to procure electricity in the absence of the RPS. Most states focus on calculating the incremental costs of RPS compliance, though three (California, Kansas, and Nevada) have published estimates of gross costs. RPS benefits are discussed in Section 4.

In general, the method by which costs may be determined depends on the regulatory structure of the state.[3] In traditionally regulated states, utilities commonly enter into long-term power purchase agreements (PPAs) for the electricity and renewable energy certificates (RECs) from a project, or build and own renewable generation projects directly. RECs represent the environmental attributes of renewable generation and are used to demonstrate compliance with the RPS. Because these long-term PPAs include both the electricity and the REC (referred to as a "bundled contract"), determining the "incremental" cost of the renewable energy requires a comparison to the cost of conventional generation that would otherwise have been procured. In traditionally regulated states, RPS costs are typically estimated by either the obligated utility or by the PUC. The general methodology for assessing costs has in some cases been outlined by statute or regulation; however, statutory or regulatory language can still be open to interpretation by the compliance entity, sometimes resulting in differing methodologies across utilities within a state.

In states with restructured markets, compliance entities are typically buying "unbundled" RECs, and thus, the incremental cost of RPS compliance is derived from the cost of RECs in addition to any alternative compliance payments (ACPs) made to achieve compliance. Most restructured states have ACPs that enable obligated entities to make a payment at a pre-established price in lieu of procuring renewables (e.g., $50/MWh). These essentially establish a ceiling on the cost of compliance because obligated entities would not enter into contracts to procure renewable generation above the ACP price. Though REC prices (in combination with ACPs) can be used to

[3] In states with restructured markets, the traditional electric utility monopoly, where the utility provides generation, transmission, and distribution, has been split. Customers in restructured states can choose which electric service company will supply their generation. In traditionally regulated states, vertically integrated utilities provide generation, transmission, and distribution service to a captive market (i.e., franchise service territory). While there is a spectrum of restructuring, for purposes of this study, we classify the following RPS jurisdictions as operating in restructured markets: Connecticut, Delaware, Illinois, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Washington, D.C.

estimate the incremental cost of RPS compliance, it is important to note that REC prices are influenced by market supply and demand, and can fluctuate widely, thus not necessarily representing the above market costs for renewable energy, as discussed further in Section 2.2. Moreover, in addition to purchasing unbundled RECs, compliance entities in some restructured markets have begun procuring more renewables through long-term bundled PPAs, which requires a different methodology to calculate the incremental cost.

This section provides an overview of the methods used to estimate the cost impacts of an RPS; Section 3 will present the results of studies done by states as well as our calculation of RPS costs, based on REC price data, ACPs, and data from long-term contracts.

We structure the section as follows: Section 2.1 discusses methods used to estimate incremental RPS compliance costs in regulated states; Section 2.2 discusses methods used in states with restructured electricity markets; Section 2.3 discusses those states that instead report only gross costs; Section 2.4 highlights other issues that impact cost estimates; and Section 2.5 provides a summary of methodological considerations.

2.1 Methods for Estimating Incremental RPS Costs in States with Traditionally Regulated Markets

In traditionally regulated states where utilities and state agencies are estimating the incremental cost to meet the RPS, a key decision is how to determine the counterfactual scenario—absent RPS procurement, what resources would have been procured, and at what cost. After the counterfactual scenario costs are determined, they can then be subtracted from the gross RPS costs to derive an "incremental" cost of RPS compliance.

Utilities in states with traditionally regulated markets generally use one of three methods, or a combination of methods, for defining the counterfactual scenario and estimating incremental RPS costs (Table 1). In some cases, the counterfactual scenario is a particular type of conventional generator, which may be established by the Commission. In other cases, utilities use wholesale prices to determine the counterfactual scenario. Finally, many utilities use modeling approaches to determine the proxy conventional generator(s) or market prices. Table 1 outlines the primary methods for determining incremental costs in regulated markets, identifies the methods used in various regulated states, and highlights a number of key considerations within those methods, as discussed further below.

Table 1. Methods for Estimating Incremental RPS Costs

<table>
<tr><th>Method</th><th>States</th><th>Key Considerations</th><th>Considerations for Multiple Methods</th></tr>
<tr><td>Compare to a proxy non-renewable generator</td><td>AZ, CA, MI, OR</td><td>• What is the process for determining the conventional generator?</td><td rowspan="3">• Over what time period are costs calculated?
• Is a carbon adder included in the non-renewable costs?
• What fossil fuel prices are assumed?
• What additional costs are included (e.g. capacity, transmission, or ancillary services)?
• Are renewable resources that were developed before the RPS implementation included?</td></tr>
<tr><td>Compare to market price</td><td>CA, MN, WA, WI</td><td>• Is the wholesale market generation shaped to match the output of the renewable energy?
• Are energy and capacity values included?</td></tr>
<tr><td>Modeling approaches</td><td>CO, MI, MN, NM, NC</td><td>• For future scenarios, what assumptions are made about load growth, environmental regulations?</td></tr>
</table>

2.1.1 Comparing to a Proxy Non-renewable Generator

Under this approach, utilities and states compare the cost of RPS resources to the levelized cost of some proxy conventional generator. The kind of proxy generator, and the set of costs included in the comparison, may be established by the commission or in statute. These costs may include (for both the renewable generation and conventional generation) those associated with fuel consumption, generation capacity, operations and maintenance, transmission, ancillary services, and emissions.

This approach takes a long-term perspective, looking at the levelized cost of a resource over its lifetime. It may also simplify the process for calculating incremental costs, compared to a modeling approach, though decisions about defining the proxy generator, timeframe of analysis, fuel costs, and other issues may complicate the process. In addition, the resulting estimated incremental costs may not represent what actually would have been used absent an RPS. This is because in practice, renewable generation could displace more than one generator type at different hours during the year, and may or may not have equal capacity value as the proxy generator. The generator type as well as the hours in which it is operated will impact the overall cost profile.

States have used different approaches to developing a proxy. Some examples include the following:

- The Michigan PUC files a report annually examining the cost of renewables procured under the RPS compared to the cost of a new, coal-fired power plant, as required by statute. The PUC report draws on data submitted in the rate-regulated electric providers' annual renewable energy plans, which must demonstrate that the "life cycle cost of renewable energy acquired, less the life cycle net savings associated with the Energy Optimization Plans, did not exceed the life cycle cost of electricity generated by a new conventional coal-fired facility (MPSC 2013, 23-24)." The PUC staff developed a guidepost for the cost of a new coal plant of $133/MWh (or $0.133/kWh), based on a 40-year life cycle and forthcoming EPA regulations.4

- In Oregon, utilities estimate incremental costs of compliance based on a combined cycle gas turbine (CCGT) proxy, unless otherwise specified by the PUC, the costs of which must be based on the most recent integrated resource plan (IRP), unless material changes have been made since then.
- Although California's cost assessment process is being revised, the historical approach for evaluating RPS costs was to compare RPS procurement to a "market price referent" (MPR). The MPR was developed by the utilities as the modeled cost to own and operate a CCGT over multiple time periods. In its most recent RPS cost report, the CPUC used a 20-year MPR of $0.101/kWh to evaluate the utilities' 2011 RPS portfolios (CPUC 2013a).

2.1.2 Comparing to Market Price

Some states and utilities are estimating incremental RPS costs by comparing the cost of renewables procurement relative to wholesale electricity spot market prices. In order to determine the market price, a number of considerations need to be weighed, including: should the wholesale market generation be shaped to match the output of the renewable energy, and are both energy and capacity market costs considered?

States and utilities have used different approaches when comparing the cost of renewables used to meet the RPS to market price. Text Box 1 describes how utilities in Minnesota have calculated incremental RPS costs, using market price as well as modeling work. Other examples using wholesale market prices as the presumed cost absent the RPS include the following:

- In Washington, the three investor-owned utilities (IOUs) are comparing the costs of renewables to the cost of purchasing an equivalent amount of energy from the wholesale market.5 As part of this process, PacifiCorp used the wholesale market price curve shaped to the output of the renewable resource. This shaping was not done by the other IOUs. Differences in methodology and other factors led to a two-fold range in reported 2012 compliance costs estimates in Washington. PacifiCorp estimated the cost of RPS compliance at $15.73/MWh while Avista's estimate was $20.35/MWh and Puget Sound Energy's estimate was $43.76/MWh (Stanfield 2013a). The Washington UTC is addressing cost standardization as it considers revisions to its RPS rules (see Docket UE-131723).
- Although California has used the MPR approach, utilities have also estimated avoided costs using a market price methodology using day-ahead market price and the cost of capacity.

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[4] The PUC staff calculation of the renewable cost includes the cost of PUC approved contracts, with the exception of Detroit Edison's and Consumers Energy's solar programs, which the PUC determined to make up less than two percent of contracts approved, on a generation basis.

[5] Washington's RPS statute defines incremental costs as "the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resources that do not qualify as eligible renewable resources, where the resources being compared have the same contract length or facility life" (RCW 19.285.050(1)(b)). The Washington PUC staff commented that use of the wholesale market price does not appear to meet the language specified in statute (Washington UTC 2013).

Compared to the MPR-based avoided cost estimate of $0.10/kWh, the utilities' estimates based on market prices were much lower, roughly $0.03/kWh, which resulted in much higher estimates for incremental RPS costs (discussed further in Text Box 3). The PUC expressed concern with this approach, noting that the results would have prevented even low-cost hydro and nuclear resources from being determined cost-effective and that the calculations were based on short-run avoided costs (CPUC 2013a).

Text Box 1. Rate Impact Calculations in Minnesota

Utilities in Minnesota have used different methods to estimate RPS incremental costs. Xcel Energy (MN) examined the cost of the renewable resources compared to the cost of the same amount of energy and capacity in the MISO market. To determine the renewable energy costs, they included the price paid for contracted energy or annual revenue requirements at their owned facilities (Xcel Energy 2011). Xcel Energy found that the rate impact for wind resources over 2008 and 2009 was approximately 0.7% less than market prices, though biomass resources were slightly higher (0.56% and 1.16% in 2008 and 2009, respectively).

Other utilities in Minnesota had different results. Of the fourteen utilities that submitted reports, eight said that complying with the renewable standard has resulted in little or no additional costs, if not a slight savings for customers, while six utilities, including Great River Energy, reported that their efforts to comply with the policy led to increased costs for customers. Great River Energy modeled a no-RPS scenario that did not include additional non-renewable resources, then compared that with the RPS scenario in which renewable energy was added to comply with the RPS. Great River Energy found that its wind energy purchases increased retail customer bills by about 1.6%, or about $18/year for an average homeowner.

2.1.3 Modeling Approaches

Modeling approaches can provide a system-wide look at the differences in resources built and dispatched with and without the addition of renewable energy (instead of just looking at one generator type or the wholesale market price). Key inputs to dispatch and capacity expansion planning models include the fuel prices for fossil generation, inclusion of environmental costs, and for models examining future scenarios, the availability of renewable energy tax credits. One advantage of the modeling approach is that it can provide a more comprehensive picture of what would have happened absent the RPS. Modeling approaches may also be able to better capture integration and transmission costs. However, modeling results are heavily dependent upon the key inputs, which are complex and subject to judgment.

States have taken different approaches to modeling approaches. Some examples include the following:

- In Colorado, statute requires that utilities estimate the incremental cost of the RPS through modeling work. Utilities must use scenario analysis, comparing the costs and benefits of the renewable energy standard plan to a plan that replaces the new renewable resources with new non-renewable resources reasonably available.
- In Minnesota, Xcel Energy used wholesale market prices to determine historic RPS costs, but used a long-term resource planning tool, Strategist, to estimate future costs. The model calculates the present value of revenue requirements for different expansion plans. Xcel developed two base models, one that met the RPS, and one that replaced all incremental wind resources with conventional resources. Three additional scenarios explored the impact of extending the PTC though 2020, placing a price on carbon dioxide emissions, and a high natural gas price scenario. There was minimal difference between the cases; the base case without the RPS resulted in 1.4% higher net present cost than the RPS case. The PTC extension, CO2 price, and high gas price cases resulted in 0.74%, 0.41%, and 0.98% higher net present costs, respectively, for the conventional resource plan than the RPS case (Xcel Energy 2011).
- In New Mexico, Public Service Company of New Mexico (PNM) calculates RPS costs for the following two years using production cost modeling. PNM models the total system costs with and without each existing and proposed renewable resources to determine the avoided fuel cost for each resource (PNM 2013a). PNM also develops a single avoided fuel cost figure, for all renewable resources, which it uses to validate the individual results and also in calculating the cost cap.
- In North Carolina, utilities use a hybrid of modeling and a proxy generator method. The incremental RPS costs are defined as those that "are in excess of the electric power supplier's avoided costs," where avoided costs include both energy and capacity (North Carolina G.S. 62-133.8(h)). Duke Energy uses the Commission-approved "peaker method" to determine its avoided costs. The peaker method calculates avoided costs based upon the capacity cost of a combustion turbine peaking unit plus the marginal running costs of the system, which are calculated based on simulation of Duke's system with and without the RPS resources (Duke Energy 2010).
- In Michigan, utilities use a hybrid method when seeking to recover the RPS costs. Incremental RPS costs are specified as the difference between the gross renewable energy costs and the "transfer price". The transfer price is determined by each utility and must reflect long-term capacity and energy, but does not need to be equivalent to the cost of a new coal-fired facility, determined by the PUC (DTE 2009). In practice, Consumers Energy has calculated the transfer price based on capacity values for a gas-fired combustion facility and energy values calculated using a dispatch model (Consumers 2009). DTE has used the annual average locational marginal prices and adjusted capacity payments, by technology, compared to a new gas-fired combustion turbine (DTE 2009).

2.1.4 *Additional Considerations for Estimating Incremental RPS Costs in Regulated States*

2.1.4.1 Timeframe of Cost Calculation

When evaluating incremental RPS costs, regardless of method, a key consideration is the timeframe to examine.

In most cases, cost calculations are made over a longer time period and then annualized to one year.[6] This recognizes that procurement to meet the RPS may be "lumpy" in nature, and that the relative cost of renewable energy to conventional alternatives will depend on future conditions, e.g., natural gas prices and environmental regulations. In states where utilities are offering an upfront solar rebate to procure supply to meet a solar carve-out, spending may be particularly front-loaded because the rebate is paying upfront for a long-term resource: for example, the utility may offer an upfront rebate per watt in exchange for the RECs produced by the system over 20 years.

For studies using the proxy generator approach, decisions will have to be made about the time over which the conventional and renewable generator costs are levelized. In Michigan, the PUC compares the costs of renewables against the 40-year life cycle cost of a coal plant. The life cycle approach and the 40-year lifetime introduce additional uncertainty into the cost of the coal plant, including uncertainty around potential future federal regulation of coal plants. For example, actual future fuel prices can differ significantly from forecasts. In addition, the costs of renewables are typically recouped over a shorter time period (15-20 years), meaning that the cost comparisons are not done over the same time period.

When examining market prices, studies consider whether to use historical market prices compared to RPS generation in each year, or to use projections of future market prices compared to the RPS resource lifetime.

On the modeling side, Missouri examines RPS compliance costs over 10 years, and then divides those costs into annual increments; if the one-year annual rate increase exceeds 1%, then the utility's RPS obligation is decreased so that rates do not exceed 1%. In order to calculate the costs over the 10-year period, the utilities estimate their cost of compliance for each year based on an RPS-case and a no-RPS case (MO CSR 240-20.100(5)).

California is in the process of developing a cost cap for its 33% RPS. As part of the process, the CPUC staff proposed using a 10-year rolling calculation. In response to the CPUC staff proposal, some parties argued that the timeframe should be longer (e.g., 20 years), in order to match the typical length of renewable energy contracts. Others argued that the cost cap should look only at procurement in an individual year.

2.1.4.2 Inclusion of a Carbon Adder

Whether using a proxy generator, wholesale market prices, or modeling tools, a carbon price could be added to the comparison scenario given that some states or utilities may have a

[6] One notable exception is in New Mexico, where rules specify that cost cap calculations shall not include annualization.

preference for procuring low-carbon resources. That is, even if there were no RPS, state regulators or utilities may have wanted to incorporate a cost of carbon when making decisions about procurement (potentially in anticipation of potential future carbon regulations). However, some argue that in markets where there is currently no carbon policy, and thus utilities are not paying a cost for carbon, adding it to the non-renewable resource cost is inappropriate.

The Colorado PUC initially required that the non-RPS scenario include a carbon adder and a capacity credit. Adding these costs to the counterfactual scenario can be contentious, as there is no existing capacity market in Colorado, nor is there a state-wide price on carbon (Stockmayer et al. 2012). In its latest RPS compliance plan, Xcel Energy (Colorado) did not include a carbon price for 2014 calculations (PSCo 2013).

California's latest MPR calculation was done in 2011, before the state's carbon cap and trade program went into effect. The CPUC determined that the market-based forward natural gas and electricity prices should be used to calculate the implied GHG price. This methodology resulted in GHG compliance costs of \$16.27/CO_2 metric tonne in 2013, increasing to \$36.64/CO_2 metric tonne in 2020 (CPUC 2011).

2.1.4.3 Inclusion of Renewable Resources Not Driven by RPS

In some cases, renewable resources that are counted towards a particular state's RPS target may have been procured independently from the RPS. The most prevalent example would be pre-existing renewable resources that were constructed or contracted prior to the RPS. Because some states allow renewable resources that were in place at the time the RPS was passed to count toward RPS compliance, a key consideration is whether the costs of those resources are included in RPS cost estimates. Because those resources would have been developed regardless of an RPS, including the costs in an incremental cost calculation would result in overestimating RPS compliance costs. In other states, pre-existing resources are not eligible to meet the RPS, so this question is not an issue.

- In Colorado, the state's largest IOU, Xcel Energy, recovers incremental costs through a surcharge on customer bills known as the RESA surcharge. The surcharge only covers the above market costs of new renewables and contracts signed after July 2, 2006 (the date of the commission order approving the RESA) (PSCO 2013c). Renewable resources that were online on or after January 1, 2004 are eligible to meet the RPS.
- In Kansas, some of the renewable projects were built prior to implementation of the RPS, but the costs are still being included in the cost calculation. For example, Kansas Electric Power Cooperative (KEPCo) is using exclusively hydropower that it has been purchasing since the 1980s in order to meet the RPS. The utility determined that the hydropower had no cost impact to ratepayers because it is the least expensive generation source (KEPCo 2013).
- In Oregon, Portland General Electric (PGE) determines an incremental cost for only one renewable resource, Bigelow Canyon. PGE owns and operates Bigelow Canyon, so it used its actual capital costs, O&M costs, capacity factor, as well as wind integration costs that were calculated as part of the IRP process to calculate the levelized cost of the wind farm, which is then compared to the life cycle costs of a combined cycle natural gas plant (PGE 2011). The rest of PGE's renewable resources have been determined to have zero incremental cost. Oregon's regulations specify that "incremental costs are deemed to be zero for qualifying

Table 2. Publically Available Information on REC Pricing

State	Type of Pricing Available	Frequency	Data Source
Illinois	Average price by product type, for each Illinois Power Agency RFP	Following approval of annual Illinois Power Agency RFP bid awards	Illinois Corporation Commission notices of RFP results
Maine	Weighted average REC price and range	Annually	Maine PUC reports[a]
Maryland	Weighted average REC price	Annually	Suppliers provide data to PUC, not published
New Jersey	Weighted average SREC price	Monthly	Website, New Jersey Clean Energy Program[b]
Ohio	Weighted average REC price	Annually	Ohio PUC reports
Pennsylvania	Weighted average REC price and REC price range	Annually	Pennsylvania PUC website and reports[c]
Washington, D.C.	Average REC price by resource type	Annually	District PSC reports[d]

[a] "Reports to the Legislature." (2013). Maine Public Utilities Commission. Accessed February 2014: http://www.maine.gov/mpuc/legislative/reports.shtml.
[b] "SREC Pricing." (2013). New Jersey Clean Energy Program. Accessed January 2014: http://www.njcleanenergy.com/renewable-energy/project-activity-reports/srec-pricing/srec-pricing.
[c] "Pricing." Pennsylvania AEPS Alternative Energy Credit Program. Accessed December 2013: http://paaeps.com/credit/pricing.do.
[d] "PSC Reports to the DC Council." (2013). Public Service Commission of the District of Columbia. Accessed December 2013: http://www.dcpsc.org/reports/dc_council.asp.
Note: Weighted average REC prices take into account the volume of RECs purchased at different prices. Washington, D.C. does not publish weighted average REC prices but does publish the average REC price by resource type.

Additional REC pricing information is provided by several SREC brokers as well as PJM-GATS, the REC tracking system for the mid-Atlantic, though each source has limitations. SREC brokers provide only information on spot market transactions.[12] PJM-GATS reports solar-weighted average prices for transactions in the PJM market that include pricing from long- or mid-term contracts as well as spot prices. PJM-GATS reports prices on a monthly basis based on when the SREC was issued, traded, or retired, not on when the generation occurred.[13] As a result of this type of reporting and the decline in spot SREC prices, the SREC prices reported in PJM-GATS have been higher than spot market SREC prices.

One final limitation associated with relying on REC and ACP costs to estimate RPS compliance costs is that a number of potentially important costs and benefits may be omitted. For example, the approach may ignore certain integration costs associated with variable RPS resources and may not fully capture transmission capacity expansion costs. This approach, however, also ignores any cost savings that LSEs may receive as a result of the reduction in market clearing

[12] For example, see www.srectrade.com or www.flettexchange.com.
[13] For example, if a company contracted for SRECs that were generated in January 2010 at a given price but did not retire those SRECs until August of 2011, the January 2010 price would be reflected in PJM-GATS's August 2011 solar weighted average price report.

prices in regional energy markets, associated with low marginal-cost renewable resources. These issues are addressed in more detail in Section 2.4.

2.2.1 *Treatment of ACPs*

Utility ACPs are a component of RPS compliance costs. Although ACPs will always – at least initially – be a cost to the utility or supplier, whether these costs may be passed through to ratepayers varies by jurisdiction (Table 3). In some states, utilities are explicitly not allowed to receive cost recovery for ACPs. In other states, cost recovery is possible, but not guaranteed. Finally, some states allow for automatic cost recovery (though, even in these cases, retail prices charged by competitive suppliers are established through market dynamics, and so pass-through of ACPs is generally not directly observable). In some states, the funds raised by ACPs collected are used to support renewable energy project development in the state, which may further reduce overall cost impacts. While the treatment of ACPs is not important in determining the cost that the supplier will initially pay to meet the RPS, it does impact the ability of compliance entities to pass on those costs, and therefore also impacts the ultimate costs that ratepayers pay for RPS compliance.

In Ohio, Pennsylvania, and Texas, utilities are not allowed to pass through ACPs to ratepayers. In Connecticut, the ACPs are used to offset other ratepayer costs, and in New Jersey, solar ACPs are refunded to ratepayers. In Delaware, Maryland, Oregon, New Hampshire, and Washington, D.C., ACP cost recovery is possible, but not guaranteed. Finally, in Illinois, Massachusetts, Maine, New Jersey (non-solar), and Rhode Island, ACP cost recovery is automatic.

Table 3. ACP Cost Recovery Provisions

ACP cost recovery provision	States
Utilities not allowed to pass through ACPs to ratepayers	OH, PA, TX
ACPs used to offset other ratepayer costs or refunded to ratepayers	CT, NJ (solar)*
ACP cost recovery is possible	DE, MD, OR, DC, NH
ACP cost recovery is automatic	IL, MA, ME, NJ (non-solar), RI

* In New Jersey, the Solar Advancement Act of 2010 required that solar ACPs be returned to ratepayers.

2.3 Gross RPS Compliance Costs

Three states (Kansas, Nevada, and California) examine gross, rather than incremental, RPS costs. Gross costs are the total costs of renewable energy procurement, as opposed to incremental costs that reflect the difference between these total costs and conventional generation. There are some advantages to examining gross costs–namely, that no modeling work needs to be done, nor does a proxy conventional generator need to be assigned. While gross costs do not allow for comparison against what would have happened absent the RPS, they can help regulators understand trends in renewable pricing, and they may be used as part of a cost cap calculation. Gross compliance costs could also be used as part of a complete cost-benefit assessment, where in avoided costs would be treated as a benefit.

The Kansas Corporation Commission (KCC) develops gross costs as part of rate impact calculations. The KCC developed regulations that require each obligated utility to submit compliance reports that detail the retail revenue requirement of renewable generation used to meet the RPS.[14] Using this information as well as volumetric sales data, the KCC calculated the rate impact on a statewide basis, thus holding confidential individual utility revenue information.

In Nevada, Nevada Power and Sierra Pacific report estimated gross RPS compliance costs for approval by the Nevada PUC. Costs include the cost of purchased power and RECs, general and administrative expenses, O&M for company-owned renewable generation, as well as costs of renewable incentive programs and energy efficiency programs. Energy efficiency can be used to meet up to 25% of the RPS target through 2014, and then this provision phases out so that by 2025, energy efficiency cannot meet any part of the RPS target.

The California PUC is in the process of developing a method for calculating and implementing a cost containment mechanism, as required by SB 2(1X), signed in 2011. The new method will replace the MPR methodology that was calculated on an annual basis by PUC staff. The California PUC staff proposal outlines a process that would calculate a procurement expenditure limit based on an IOU's RPS gross procurement expenditures divided by the IOU's total revenue requirement on a rolling 10-year basis (CPUC 2013b).

2.4 Including Other Expenses in RPS Cost Calculations

In some cases, factors that affect the economic value or costs of renewable resources may not be reflected in REC prices or in the costs that utilities and states include when estimating the incremental cost of RPS resources. Although typically RPS cost assessments look exclusively at the cost of renewable generation or RECs, some assessments also include information about non-renewable generation that is eligible for the RPS (e.g., energy efficiency) or indirect and/or administrative expenses.

2.4.1 Integration Costs and Network Transmission Costs

Two costs in particular – integration costs and network transmission costs – are often not allocated to the renewable generator and are instead borne by other users or by the power system. Thus, although these costs are not typically included in RPS incremental cost estimates, this section provides information on other estimates of integration and network transmission costs.

In the U.S. numerous studies estimate integration costs for wind to be less than $5/MWh even with very high wind penetration levels (>20% penetration on an energy basis), though some smaller individual utilities estimate costs up to $12/MWh, and one utility (Idaho Power) estimated cost over $18/MWh (Wiser and Bolinger 2013).

Aside from forward looking studies, two other indicators of integration costs are actual integration tariffs charged to wind generators in particular balancing areas (which may already be reflected in REC prices for those wind generators) and backward looking assessments of integration costs by system operators with significant amounts of wind. Retrospective analysis of actual wind balancing reserves and integration costs in ERCOT (with 8.5% wind penetration on an energy basis) resulted in wind integration costs on the order of $1.2/MWh (Maggio 2012). Actual wind integration charges by several different entities in the U.S. (Bonneville Power

[14] The retail revenue requirement is defined as: (Rate base * Rate of return) + O&M + Administrative & General Expenses + Depreciation + Taxes.

Administration, Westar Energy, Puget Sound Energy, and the Nebraska Public Power District) range from \$0.70 to \$6.85/MWh (Wiser and Bolinger 2013).

Network transmission upgrades (as opposed to dedicated grid-tied assets) are used by multiple resources on the grid and often have many beneficiaries. Challenges in quantifying benefits for specific beneficiaries of long-lived transmission assets has led to network transmission costs often being allocated to loads rather than particular generators. In these cases, the cost of renewable resources will not reflect the cost of network transmission investments needed to deliver power to leads. One assessment of the costs of transmission for wind implied by various planning studies in the U.S. found a median transmission cost of \$15/MWh (Mills et al. 2012).

California's Section 910 Report acknowledges that for indirect costs, "it does not appear that the utilities use a consistent methodology to track these expenditures, that these costs are tracked in a manner that allows clear attribution to the RPS program, or that it is always possible to determine what portion of the costs should be attributed to the RPS program" (e.g., transmission costs) (CPUC 2013a, p. 5).

In Minnesota, however, utilities are required to estimate the rate impact of the RPS, including energy purchases, generation facility acquisition and construction, and transmission improvements (Minn. Stat. Section 216B.1691 Subd. 2e.). Xcel Energy (MN) recognized that new transmission lines have multiple benefits, making it difficult to allocate costs; as such, they only provide a "rough estimate" of transmission costs associated with the RPS (Xcel Energy 2011, p. 10).

The New Mexico Public Regulation Commission (PRC) ruled in November 2013—after years of discussion about how to calculate costs pursuant to the state's cost cap—that cost calculations can include O&M, back-up and load following generation, off-system sales opportunity impacts, or other facilities and improvements or functions that may be required (NM PRC 2013a). In January 2014, however, the PRC agreed to re-hear the case, as requested by the New Mexico Independent Power Producers (NMIPP). NMIPP argues that the new cost methodology includes "expansive new costs of renewable energy while narrowing the benefits of renewable energy (NMIPP 2013, p. 10-11)" and does not reflect the intent of the states' RPS policy or the comments submitted in the case.

2.4.2 Inclusion of Administrative Expenses

Another methodological consideration is whether to include other indirect costs, such as administrative expenditures. Administrative expenses may also be easy to track on a gross basis, but difficult to determine on an incremental basis, as it is likely unknown what the administrative expenses would have been to procure non-RPS resources.

Although most states have not addressed administrative expenses, in Nevada, utilities include administrative expenses in their gross cost calculations and in Colorado, administrative expenses are limited by statute to 10% of total annual RPS revenue collection. However, Colorado utilities can request a waiver during the ramp-up stage of the RPS program. This presumably acknowledges that administrative expenses may be higher in initial years due to start-up costs.

2.4.3 Treatment of Energy Efficiency Eligible to Meet RPS

Seven state RPS policies (Michigan, Ohio, Pennsylvania, Connecticut, Hawaii, Nevada, and North Carolina) include energy efficiency as an eligible resource (though energy efficiency is being phased out as an eligible resource in Nevada). These policies cap the amount of energy efficiency that can be used and to the extent that data are available, energy efficiency is generally being used to the maximum amount allowed (Heeter and Bird 2013).

Little cost data on energy efficiency being used to meet RPS policies are available. However, Michigan looks at the weighted average cost of energy efficiency and incorporates that figure into the cost of RPS compliance. The weighted average cost of energy efficiency was $20/MWh, compared to the weighted average cost of renewable energy at $83/MWh. Together, the combined weighted average cost of energy efficiency and renewable energy was $46/MWh.

In Connecticut, the state uses a separate tier for energy efficiency. Compliance is achieved through the use of credits, and some price information is available for those credits from brokers.

Pennsylvania publishes data on an annual basis for its Tier II RPS, for which energy efficiency is eligible, but appears to not be making a major contribution. Of over 9,000 registered facilities, there are only a dozen energy efficiency or demand side management (DSM) facilities. In addition, in 2012, there were no EE or DSM credits retired to meet the RPS.

2.5 Summary of Methodological Considerations

In order to assess the impact of RPS policies, incremental cost estimates are preferable, rather than estimates of gross costs. While gross compliance costs can help understand trends in renewable pricing, if not netted out from benefits, they can overestimate the actual policy costs since other energy sources would have been used to meet loads absent the RPS. The use of renewable sources could displace some need for fossil fuels use in existing generators, and, in many cases, could displace the need for other fossil-fuel-based generation capacity.

At the same time, calculating incremental costs can be challenging; given the number of ways in which incremental cost calculation methodologies can differ, several state PUCs have begun discussions about how to standardize RPS cost calculations. These standardization efforts are underway or recently concluded in California, Delaware, Minnesota, Oregon, and Washington (see Text Box 2 for more detail).

Text Box 2. State PUC Cost Standardization Efforts

In California, the PUC is developing a methodology to calculate spending limits to meet the state's 33% RPS requirement. The PUC has issued a staff proposal on the methodology; stakeholders have developed alternative proposals and comments on all proposals are due in March 2014 (CPUC 2014).

Rulemaking is underway in Delaware to clarify the state's RPS cost cap provision. Draft regulations specify that the Division of Energy & Climate will determine the cost of compliance, which will then be review by the Director. The Division Director shall then determine the whether to freeze RPS requirements. As part of that determination, draft regulations specify that the Director may consider benefits such as price suppression, savings in health and mortality costs, and economic development benefits from renewable energy deployment in the state. (DE DNREC 2013)

The Minnesota PUC is developing a uniform reporting system for RPS rate impact data. The PUC is currently accepting comments on general guiding principles for cost impacts as well as on a uniform reporting system. The general guiding principles proposed by the PUC staff include: Foster transparency; support consistency, coordination and non-burdensome administration; provide realistic representation of baseline, actual (to date) and future expected costs; and enable comparison across utilities. (MN PUC 2013).

In Oregon, a methodology for calculating incremental RPS costs was developed but it was noted that the assumptions would be modified as utilities gained more experience with the incremental cost calculation. The PUC held workshops in 2012 and 2013 to discuss such issues; the PUC approved a stakeholder agreement in January 2014. The agreement continues use of a CCCT as a proxy generator. The parties did not agree on whether a capacity payment should be included, but they did agree that utilities should consider incorporating a capacity value. Utilities will also provide an additional scenario that assumes reduction in long-term fuel price risk. (PUC OR 2014)

Rulemaking is underway in Washington, where the PUC has an open rulemaking to address modifications to the RPS (UE-131723). Some stakeholders have expressed interest in creating a uniform approach to calculating incremental costs of RPS.

Currently, incremental RPS costs are being examined in traditionally regulated states by comparing RPS costs to a proxy generator, to market electricity prices, or through modeling approaches. Each of these three methodologies has advantages and disadvantages:

- Using a proxy generator may be a simpler approach but may not represent what actually would have happened absent an RPS as well as using wholesale market prices or a modeling approach. The proxy generator may not be the type of resource that is always displaced, because the renewable resources may displace different types of resources over the course of the day. In Minnesota, Minnesota Power submitted comments to the PUC suggesting that electricity from generating facilities or contracts that became operational before June 6, 2007 and for certified low-impact hydroelectric facilities under ORS 469A.025(5)" (OAR 860-083-0100(1)(i)).

- Ameren Missouri, which owns a hydro facility that is eligible to meet Missouri's RPS, values the RECs generated by that facility at zero cost. Ameren Missouri notes that the capital and operational expenses for the facility are already included in existing rates, therefore, there are no additional costs to use the generated RECs for RPS compliance (Ameren Missouri 2013a).

Another example of renewable resources that may be procured independently from an RPS are upgrades to hydroelectric facilities, which are often treated as an eligible RPS resource. This issue has arisen in Washington, where some utilities have included the cost for efficiency upgrades at hydropower facilities. Hydropower upgrades are eligible to meet the RPS, but the upgrades were required by the Federal Energy Regulatory Commission; therefore, the upgrades would have occurred even if there were no RPS in Washington. In Washington, PacifiCorp has not included hydropower upgrades in its incremental RPS cost calculation, while Avista has included the cost of hydropower upgrades (Pacific Power 2013a; Avista 2013).

2.2 Approaches for Estimating Incremental RPS Costs in States with Restructured Electricity Markets

In restructured markets, as electricity rates are not regulated, obligated entities typically do not disclose the cost to meet RPS.[7] In some restructured markets, however, information on the cost of RECs is required to be provided and these costs, along with the costs of ACPs, can be used to estimate incremental RPS costs. RECs can be purchased separately from electricity, and in such cases, it is commonly assumed that the RECs represent the incremental RPS costs, as the RECs would not have been purchased absent an RPS.[8] There are, however, a variety of limitations with this approach, most notably, REC price volatility, limited REC price transparency (especially for medium- and long-term REC price contracts), and the fact that REC prices and ACPs ignore a number of potentially important costs and benefits from renewable energy.

REC prices do not necessarily reflect the underlying cost of renewable electricity generation, because they are influenced by supply and demand in the marketplace. There is substantial variability in REC prices from year to year depending on how states are meeting their RPS targets. In oversupply situations, REC prices can fall dramatically while in shortages they can rise to the level of the ACP. Therefore, cost calculations based on REC pricing can vary considerably from year to year. In the next section, we examine costs over a three-year period to try to capture this variability.

In addition, there is a lack of transparency in REC prices. Many load-serving entities enter into multi-year contracts for RECs–usually not more than three years–to meet RPS requirements. Little publically available data are available on these contracts. Spot market transaction data are available from some brokers, and can be used as a proxy, but these prices can differ from the

[7] REC prices paid by utilities in regulated states are also often deemed confidential by the PUCs and therefore they are not made public.

[8] For additional information on RECs, see Heeter and Bird (2011).

longer-term bilateral transactions. The source of data and assumptions about REC prices can substantially influence the cost calculation.[9]

In Illinois, Maine, Maryland, New Jersey, Ohio, Pennsylvania, and Washington, D.C., data on REC pricing and use of ACPs as purchased and employed by compliance entities are publically available (Table 2).[10] Publically available data sources for these states provide information on the cost of the RECs retired, including those RECs that were procured under long-term contracts, which may be procured at a higher or lower price than is seen in the current spot market.

However, in New Jersey, only data on solar RECs are comprehensive, because the Board of Public Utilities (BPU) set up a system for collecting data on the price of solar RECs as of the last transaction before a REC is used for compliance. However, for Class I RECs[11], the same data are not collected on every transaction. As a result, in order to estimate costs, the New Jersey Office of Clean Energy relies on REC pricing information from other sources (e.g., brokers) (NJ BPU 2011).

In Delaware, Massachusetts, New Hampshire, Rhode Island, and Texas, no such publically available source on the REC prices paid by compliance entities is available. In these states, available spot market REC pricing from REC brokers can be used to approximate the cost of RPS compliance. Broker prices may represent a small volume of transactions, however, and it is uncertain how indicative they are of the average price of all RECs used for compliance by obligated entities.

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[9] One example of REC price approximation comes from by New Mexico, a traditionally regulated state. Southwestern Public Service Company (SPS) used a proxy REC price to determine RPS costs associated with two bundled PPAs for wind generation. To determine a proxy REC price, SPS examined REC prices in the national, western U.S., and Texas REC markets ($0.89/MWh, $2.31/MWh, and $1/40/MWh, respectively). The proxy REC price agreed upon was $1.35/MWh, slightly less than the average of the three markets, recognizing that REC prices are decreasing and that SPS has been unable to sell existing RECs into the western U.S. REC market (NM PRC 2011).

[10] REC pricing data from Maryland have been provided upon request to the PUC. Data from other states may also be available by request.

[11] Class I RECs are for the primary RPS target.

using a combined cycle proxy unit could understate the costs of the RPS because natural gas is not the marginal unit in both on- and off-peak time periods.15

- Comparing to a wholesale market price requires determining a number of variables, including whether wholesale market generation is shaped to match the output of renewable energy. In Washington State, utilities have taken different approaches towards shaping the wholesale market generation, and the Washington UTC is examining cost standardization.
- Modeling approaches can more fully explore alternative options beyond using a single proxy generator and can assess capacity savings. However, stakeholders may disagree on the appropriate modeling inputs, for example, whether to include carbon or other adders in the non-RPS scenario. If a carbon price is added to the cost of non-renewable generation, then the resulting incremental cost will be lower than if a carbon price is not added.

Within each primary methodology (proxy generator, market price, or modeling), a number of key considerations can influence the magnitude of the resulting incremental cost:

- **Including pre-RPS renewables.** Including pre-RPS renewables in the cost calculation will overestimate the cost of meeting the RPS, since the pre-RPS renewables would have been developed regardless of the RPS policy.
- **Indirect expenditures.** Indirect expenditures, such as integration costs, transmission or distribution expenditures, or administrative expenditures, can be challenging to quantify, as they may be related to both renewable and non-renewable energy; if including indirect expenditures in an incremental RPS cost calculation, the indirect expenditures should also be incremental. If the RPS were not implemented, there would likely be expenses associated with procuring non-renewable generation.
- **Plant lifetime.** Assumptions about the operating life of a non-renewable plant can introduce uncertainty about future fuel costs. For example, fuel costs for a coal or natural gas plant become more uncertain when a longer plant life is assumed. For renewable resources, the assumed lifetime can also impact the levelized cost of the generation.
- **Annualizing costs.** Annualizing costs can account for the "lumpiness" of renewable energy procurement, but may obscure annual ratepayer impact. If a utility is making large investments on a non-annual timeframe, it may see higher costs in some years than others. For example, if a utility is operating a solar rebate program, it may provide upfront financial incentives in exchange for the RECs produced by the solar system over its lifetime.
- **Including energy efficiency.** Including energy efficiency in an incremental RPS cost calculation provides an assessment of total policy costs, where standards are combined, but could complicate the ability to assess the renewable energy costs. However, most states have moved to separate standards or tiers for renewable energy and energy efficiency, which eliminates competition between the two resource types (Heeter and Bird 2013).

In restructured markets, incremental RPS costs are typically calculated using REC prices. This reflects the cost that load serving entities must pay to achieve compliance, but may not reflect the

[15] The Minnesota PUC is currently considering accepting comments on the utility cost impact reports required by statute (Docket E999/CI-11-852).

cost of developing renewable generation in the region. In addition to some of the considerations listed above, using a REC price approach can be limited because REC prices may fluctuate dramatically based on supply and demand considerations, which can substantially differ from the levelized cost of the renewable energy developed. The treatment of ACPs will also influence how closely the costs incurred by the compliance entity track the costs passed on to ratepayers. Another consideration is the source of the data on REC prices. PUCs collecting data on the price of RECs retired to meet the RPS will have a more precise representation of the RPS costs, compared to using prices from a broker.

3 Incremental RPS Compliance Costs: Historical Data for 2010 to 2012

This section summarizes and compares estimated incremental RPS compliance costs for the period 2010 to 2012.[16] For states with restructured markets, we estimate RPS costs using available REC price data and ACP prices and volumes. For traditionally regulated states, we instead rely upon RPS cost estimates reported directly by utilities or regulators, translating those results, where necessary, into a set of common metrics. As discussed in Section 2 and described further below, the cost estimates for regulated states employ widely varying methods and assumptions (see Figure 1). As such, the estimated costs itemized in this section do not result from the application of a standardized approach or the use of a consistent set of underlying assumptions. Because the reported values may differ from those derived through a more consistent analytical treatment, we do not provide an aggregate national estimate of RPS costs.

The section also provides data on RPS surcharges levied on customer bills, for states where such mechanisms are in place; those surcharges represent the net cost borne directly by customers. Finally, the section assesses the potential for increases in RPS compliance costs as RPS targets rise, and for cost caps to become binding.

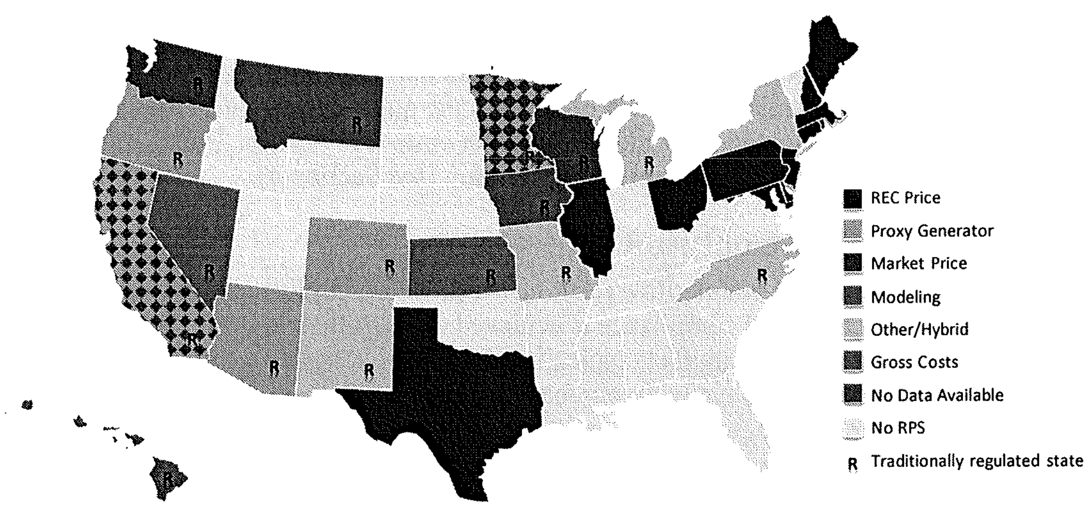

Figure 1. Overview of methodologies used to calculate RPS costs

Note: While there is a spectrum of restructuring in states, for the purposes of this study, we classify the following RPS jurisdictions as operating in traditionally regulated markets: Arizona, California, Colorado, Iowa, Kansas, Michigan, Minnesota, Missouri, New Mexico, North Carolina, Oregon Washington, Wisconsin, and Wyoming.

Two metrics are used within this section to describe incremental RPS costs:

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[16] We examine a multi-year period in order to capture fluctuations in REC pricing and to expand the scope of states that can be included, given varying data availability in some states from year to year. As of this report writing, insufficient data for 2013 were available for inclusion.

- *Dollars-per-MWh ($/MWh) of renewable energy required or procured.* This metric represents the average incremental cost of RPS resources relative to conventional generation. It answers the question: On average, how much more was paid for renewable energy than for an equivalent amount of conventional generation?
- *Percentage of average retail electricity rates.* This metric represents the dollar magnitude of incremental RPS costs relative to the total cost of retail electricity service (generation, transmission, and distribution). It answers the question: How significant are RPS costs compared to the overall cost of retail electricity service, and what impact might that have on electricity prices faced by consumers?

Several general caveats about the estimated incremental cost data must be stated up front. First, comparisons across states are highly imperfect, given the widely varying methods and assumptions employed to estimate incremental costs. This is particularly true among regulated states where we rely upon estimates produced by utilities and regulators. To the extent possible, we highlight instances where these methodological differences may be a particularly significant driver for the results observed, though ultimately the available information does not allow for a rigorous analysis of this issue. Second, the incremental cost data represent the estimated net cost of RPS compliance *to utilities* (or to LSEs, more generally). Accordingly, they do not represent net costs to society at large, which would require a broader set of considerations (some of which are discussed in Section 4). Utility compliance costs also should not be equated to ratepayer costs, as the two may diverge for a variety of reasons.[17] Third, the incremental cost estimates presented here may omit both certain costs and benefits borne by utilities. Elsewhere within the report, we discuss the potential magnitude of perhaps the most significant of these omitted items: on the cost-side, integration and network transmission costs (see Section 2) and among the benefits, wholesale electricity market price suppression (see Section 4).

3.1 States with Restructured Markets

In restructured markets with competitive retail markets, RPS compliance obligations are generally placed on LSEs, and compliance is achieved through the purchase and retirement of RECs. Retail suppliers in these markets typically do not have long-term certainty regarding their load obligations, and therefore typically purchase RECs through short-term transactions (e.g., spot market purchases or two- to three-year "strips") for unbundled RECs. In recent years, longer-term (i.e., 10- to 20-year) contracting for bundled or unbundled RECs has become more prevalent, particularly among default service suppliers and as the result of requirements or programs established to facilitate financing for renewable project developers.[18]

Many RPS policies divide the overall RPS target into multiple resource tiers or classes, each with an associated percentage target. These typically consist of some combination of a "main tier" for those resources deemed to be most preferred or most in need of support (e.g., new wind, solar,

[17] For example, ACPs and financial penalties are costs to the utility but are not always allowed to be recovered from ratepayers, or are often used to fund customer rebate programs. More generally, in regulated markets, the timing and extent to which RPS costs are passed through to ratepayers is subject to the ratemaking process within each state, while in competitive markets, the degree to which RPS compliance costs are passed through to retail electricity prices depends upon the competitive dynamics of the market.

[18] Default service, sometimes also called Provider of Last Resort service, is the retail supply option for customers that do not choose a competitive retail supplier, and is often provided by the regulated distribution service company.

geothermal, biomass, small hydro); one or more "secondary tiers" (e.g., existing renewables that pre-date the RPS, large hydro, municipal solid waste); and a solar or distributed generation (DG) set-aside. Most states with restructured markets include an ACP mechanism whereby an LSE may alternatively meet its obligations through issuing a payment to the program administrator, the dollar amount of which is determined by multiplying the LSE's shortfall by a specified ACP price. In effect, the ACP price serves as a cap on REC prices, at least when ACPs can be recovered from ratepayers, as LSEs generally would not pay more than the ACP rate for RECs.

3.1.1 Methodology and Data Sources

In general, we estimate incremental RPS compliance costs based on REC and ACP prices and volumes for each tier.[19] For several states, exceptions (New York) or slight variations (Illinois and Delaware) on this approach were used.[20] Again, these estimates represent the costs borne by LSEs, which may differ from the costs ultimately borne by customers, especially in cases where ACPs are not recoverable from customers. We translate these dollar costs into $/MWh by dividing by the amount of renewable generation required, and into a percentage of average retail electricity rates based on obligated LSEs' retail sales and average statewide retail electricity prices published by the U.S. Energy Information Administration (EIA) (EIA 2013).

The primary data sources used to compute incremental RPS costs are summarized in Table 4. For REC prices, we rely on PUC-reported data for the average price of RECs used for compliance in each year, wherever such data are available. Those prices, which are often based on data reported confidentially by individual LSEs, are presumed to reflect the cost of all RECs retired to fulfill the RPS obligation in each year, including short-term purchases of varying durations as well as RECs purchased under longer-term contracts. If PUC-reported REC price data are unavailable, we instead use the average of monthly spot market prices published by REC brokers (Marex Spectron for main tier and secondary tier RECs and a combination of sources for SRECs). Broker-reported spot market data were supplemented, when possible, with REC pricing data for any long-term contracts that may have been in effect during the 2010-2012 period. Data on long-term contract pricing for New England states was provided by Sustainable Energy Advantage (SEA) and for Delaware was obtained from Delmarva Power & Light's Integrated Resource Plans.[21] Volumes of REC retirements and ACPs are generally based on *ex post* data published in utility or PUC compliance reports or otherwise obtained directly from PUC staff. ACP prices are typically established by statute or regulation; main-tier and secondary-tier ACPs are generally

[19] Specifically, incremental costs are calculated according to: $C = \sum_{i=1}^{n}\left[\left(P_{REC,i} \times Q_{REC,i}\right) + \left(P_{ACP,i} \times Q_{ACP,i}\right)\right]$, where C is the calculated incremental compliance cost (in dollars) for a particular state in a particular CY, n is the number of resource tiers within the RPS, P_{REC} is the average annual REC price, Q_{REC} is the number of RECs retired for RPS compliance purposes, P_{ACP} is the ACP price, and Q_{ACP} is the number of ACPs issued.

[20] For New York, we calculate incremental RPS costs based on reported expenditures by the New York State Energy Research and Development Agency (NYSERDA), which procures RECs on behalf of the state's IOUs. Those expenditures consist primarily of costs to procure RECs for the main tier and the cost of incentive programs for the distributed generation set-aside, as well as administrative costs. For Illinois, compliance costs for default service load are based estimates reported directly by the Illinois Power Agency (IPA), which reflect the cost of RECs procured by IPA on behalf of default service customers. For Delaware, 2012 compliance costs for Delmarva are based on the surcharge collections, which are a direct pass-through of REC costs.

[21] SEA provided data on long-term REC contract pricing based on its own internal research and analysis. For bundled contracts, SEA estimated the implied REC price premium based on a comparison of the bundled renewable PPA prices to market prices for energy and capacity.

are either fixed over time or increase with inflation, while solar ACPs often decline according to a pre-specified schedule (see Table 5 for ACP rates in effect during 2010-2012).

There are various limitations inherent in our approach to estimating incremental RPS costs for restructured markets, including the following:

- *Omitted costs and savings.* As noted previously, REC and ACP costs do not capture the full range of costs and benefits to the LSE. Of particular note, perhaps, are the omission of integration costs and the omission of savings from reductions to wholesale energy market clearing prices. As discussed in Section 2, wind integration cost studies have yielded a wide range of estimates, though generally less than $5/MWh up to relatively high penetration levels. Wholesale market price reductions, in comparison, have often been estimated through modeling to be on the order of $1/MWh or less (for all generation in the market). However, this price suppression benefit expressed as a fraction of renewable energy generation can be substantially larger in some cases, with estimates ranging from $2-50/MWh, as discussed further in Section 4.
- *Limited REC price transparency and liquidity.* Broker-published REC price indices may be a poor proxy for the average price of all RECs used for compliance. This may occur in cases where a significant portion of REC transactions are occurring through long- or medium-term contracts and/or if broker prices are based on a small volume of transactions, in which case they may not even be representative of spot market prices as a whole. We attempted to mitigate these potential issues by relying, wherever possible, upon PUC-published average REC prices and available long-term contract data. However, for some states and years, spot market index prices were the only available data source and were therefore used in isolation (specifically, for DC in 2012, New Jersey in 2012, Ohio in 2010, Pennsylvania in 2012, and Texas in 2010-2012).
- *REC price volatility.* Although not a limitation of the methodology, per se, REC prices–and hence RPS compliance costs–can be quite volatile, with large swings from year-to-year depending on whether the state is under- or over-supplied. This fundamental feature of many RPS markets tends to complicate and obscure cross-state comparisons and long-term temporal trends of RPS compliance costs. This volatility also underscores the importance of recognizing that REC prices in any particular year do not necessarily reflect the underlying incremental levelized cost of renewable generation.

Table 4. Data Sources Used to Calculate RPS Compliance Costs for Restructured States

State	REC prices*	REC and ACP volumes**
CT	Spot market data, SEA long-term contract data	Decisions issued by the Connecticut Department of Public Utilities Authority in annual RPS compliance dockets (CT PURA, 2013)
DC	DC PSC annual reports for 2010 and 2011 (DC PSC, 2012b and 2013), spot market data for 2012	Personal communication with DC PSC staff
DE	Spot market data and Delmarva IRP (DP&L 2012) for 2010 and 2011, RCPR rider for 2012	Personal communication with DE PSC staff
IL	RPS compliance costs for the IOUs are provided directly within IPA's Annual Report on RPS Costs (IPA, 2013); REC and ACP volumes for competitive suppliers are based on personal communication with ICC staff (Zuraski, 2014)	
MA	Spot market data, SEA long-term contract data	Annual compliance reports issued by the Massachusetts Department of Energy Resources (Massachusetts DOER 2012a and 2013a)
MD	MD PSC staff	Personal communication with MD PSC staff
ME	ME PUC annual reports for 2010 and 2011 (ME PUC 2012 and 2013), spot market data for 2012, SEA long-term contract data	ME PUC annual reports (ME PUC 2012 and 2013)
NH	Spot market data, SEA long-term contract data	New Hampshire PUC annual RPS compliance reports (NHPUC 2011a, 2012, 2013)
NJ	NJ BPU staff for 2010 and 2011, spot market data for 2012	Personal communication with NJ BPU staff
NY	RPS compliance costs based directly on NYSERDA's reported annual RPS expenditures (NYSERDA 2011, 2012, and 2013a); REC volumes estimated based on contract start dates and maximum deliveries	
OH	Spot market data for 2010, OH PUC annual report for 2011 and 2012 (PUCO 2013a, 2014)	OH PUC annual reports (PUCO 2012, 2013a, and 2014)
PA	PA PUC annual reports for 2010 and 2011 (PPUC 2012 and 2013), spot market data for 2012	PA PUC annual reports (PPUC 2012 and 2013)
RI	Spot market data, SEA long-term contract data	RI PUC annual reports (RI PUC 2012 and 2013)
TX	Spot market data	ERCOT annual reports (ERCOT 2012 and 2013)

*Spot market data typically consist of monthly bid and offer prices and monthly closing prices for RECs of a particular state, resource tier, and vintage. For main tier and secondary tier REC spot market prices, we rely on data published by Marex Spectron. For SREC spot market prices, we average data across Spectron, SRECTrade, and Flett Exchange; if none of those indices are available for a particular market, we use data from PJM-GATS.
** Historical data on REC retirement and ACP volumes were not available for all years during the 2010-2012 period. In those instances, compliance costs were estimated by simply multiplying the applicable REC prices (spot market or otherwise) by the estimated RPS requirement. This approach was used for CT (2011 and 2012), DC (2011 and 2012), DE (2012), MA (2012), ME (2012), NJ (2012), and PA (2012). Given that REC prices will approach the ACP during periods of shortage, this approach should produce a similar result as what would be obtained under the more general methodology used.

Table 5. ACP Rates: 2010-2012 ($/MWh)

State	Main Tier	Secondary Tier	Solar/DG Set-aside
CT	$55	$55	n/a
DC	$50	$10	$500
DE	$25-80	$25-80	$400-500
IL	$5-14 (ComEd territory) $4-10 (Ameren territory)	n/a	Same as Main Tier
MA	$60.9-$64.0	$25.00-26.28 (existing RE) $10-10.5 (waste-energy)	$550-600
MD	$40	$15	$400
ME	$60.9-$64.0	n/a	n/a
NH	$55-60.9 (Class I RE) $25 (Thermal)	$29.9-31.5 (Class III) $26.5-29.9 (Class IV)	$55-160
NJ	$50	$50	$658-693
OH	$45-$47.6	n/a	$350-400
PA	$45	$45	$550.2**
RI	$60.9-64	$60.9-64	n/a
TX	$50	n/a	n/a

* ACP rates for IL have been translated into the typical units of $/ MWh of renewable energy, for comparison to other states.
** Fluctuates according to a formula as follows: 200% X (market value of SRECs + levelized value of solar rebates). The current value applies to 2008/2009.

3.1.2 REC Prices

REC spot market prices for the 2007-2013 period are presented in Figure 2, which differentiates between REC prices for the main tier, secondary tier, and solar set-aside in each state, as applicable.[22] As shown, REC spot market prices vary considerably over time, according to shifts in the balance of supply and demand (sometimes induced by revisions to RPS rules and eligibility requirements), but do not necessarily correspond well to trends in underlying renewable energy technology costs. REC prices also vary considerably across states, though main tier REC prices tend to be clustered regionally among the ISO-NE and PJM states, where inter-state REC trade is most prevalent. Solar set-aside markets, in comparison, tend to be somewhat more balkanized, as many states effectively limit eligibility to in-state systems.

Within the narrower timeframe of our historical analysis period (2010-2012), main tier REC prices in northeastern states rose from roughly $15/MWh as regional REC supplies tightened and shortfalls emerged. As of year-end 2012, main tier RECs in all New England states other than Maine were trading near their respective ACP prices ($55/MWh in Connecticut and New Hampshire and roughly $65 in Massachusetts and Rhode Island). Ohio In-State RECs followed the opposite trajectory, trading at a relatively high price of roughly $30/MWh in 2010 before dropping steadily over the course of 2011 and bottoming out below $5/MWh throughout 2012. Main tier RECs in all other states have remained in a prolonged period of oversupply and have traded below $5/MWh more or less continuously since 2010.

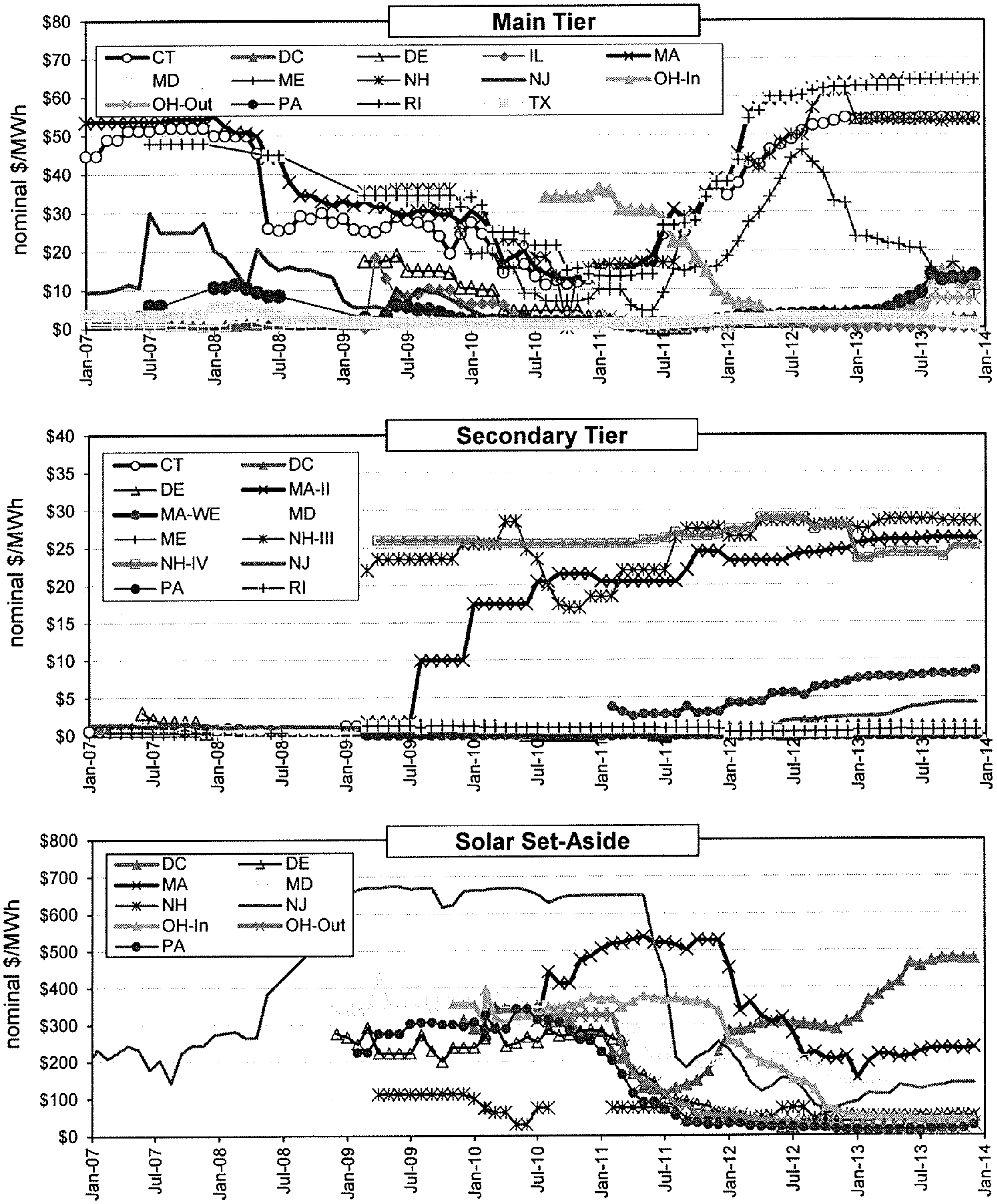
[22] The figure also differentiates between prices for Ohio In-State and Out-of-State RECs, and between the multiple secondary tiers in Massachusetts and New Hampshire. For information on what kinds of resources are included in each state's RPS tiers, refer to the state RPS policy summaries posted on DSIRE: http://www.dsireusa.org.

Secondary tier REC markets, which typically trade below main tier REC prices because of lower technology costs or inclusion of pre-existing resources, have also been persistently oversupplied in most states, with prices generally remaining below $1/MWh. Notable exceptions are Massachusetts and New Hampshire, where significant shortfalls have arisen and secondary tier REC prices have remained relatively high (at or near their respective ACP prices). Massachusetts has two secondary tiers: a Class II tier for existing renewables (of the same technology types as qualify for the main tier) and a Waste Energy tier for municipal solid waste. The Massachusetts Class II market has remained undersupplied, due in large part to a shortage of existing biomass units that meet the requisite emissions criteria (DOER 2012b). New Hampshire similarly has two secondary tiers: Class III for existing biomass and landfill gas and Class IV for existing small hydro. Although the state has sufficient in-state resources to meet the targets, both tiers have experienced shortfalls due to competition for those RECs with neighboring states.

SREC prices have historically been significantly higher than main tier or secondary tier REC prices due to the higher underlying technology costs for solar and correspondingly higher ACPs. Throughout 2010, for example, SREC prices for most state markets were trading in the $200-$350/MWh range (and above $600/MWh in New Jersey, which had a much higher solar ACP and higher solar targets). The lone exception is New Hampshire, where SREC prices have remained persistently low. This is partly due to the fact that the state allows participation by SRECs generated in other states, including SRECs produced in Massachusetts that are ineligible for that state's solar set-aside and SRECs produced in other northeastern states without an RPS solar set-aside. In addition, under certain circumstances, utilities are able to claim title to SRECs produced by customer-sited PV systems in New Hampshire without any payment to the customer.

Within the past several years, however, many SREC markets have become significantly oversupplied as a result of steeply falling PV module prices and, to varying degrees, the availability of financial incentives for solar. SREC prices have correspondingly dropped, in some cases quite precipitously. As of year-end 2012, SRECs in Delaware, Maryland, New Hampshire, New Jersey, Ohio, and Pennsylvania were trading near or below $100/MWh (in some cases well below). SREC prices in Massachusetts also fell markedly over the course of 2012, though not as far as in other states, due partly to the state's SREC clearinghouse, which serves as a partial price support mechanism.[23] In addition, Massachusetts announced in 2013 that it would expand its solar set-aside targets. Only in Washington, D.C. have SREC prices followed a generally increasing trajectory over the period shown; the market has remained undersupplied due partly to its unique geographical constraints (i.e., a single urban area with limited potential for large projects), and also due to a tightening of the geographical eligibility rules in 2011.

[23] Massachusetts Department of Energy Resources (DOER) administers an annual auction, with a fixed-price of $300/MWh (less a $15/MWh administrative fee), in which any unsold SRECs from the previous year can be deposited for sale. There is no guarantee that SRECs placed into the auction will be sold, and thus the auction price serves only as a "soft" price floor.



Sources: Spectron, SRECTrade, Flett Exchange, PJM-GATS, and NJ Clean Energy Program. Depending on the source used, plotted values are either the mid-point of monthly average bid and offer prices, the average monthly closing price, or the weighted average price of all RECs transacted in the month, and generally refer to SREC prices for the current or nearest future compliance year traded in each month. In Main Tier and Solar Set-Aside graphics, "OH-In" and "OH-Out" refer to OH In-State and OH Out-of-State RECs. In the Secondary Tier graphic, MA-II and MA-WE refer to MA Class II and MA Waste Energy RECs, respectively, while NH-III and NH-IV refer NH Class III and Class IV RECs.

Figure 2. REC spot market prices

3.1.3 *Estimated incremental RPS Costs per Unit of Renewable Generation*

We use the spot market REC prices reported in Figure 2, in combination with the other data described in Tables 4 and 5, to estimate total incremental RPS compliance costs in each state. The results of those calculations are presented in Figure 3 in terms of \$/MWh of renewable energy required. In effect, these values are an estimate of the weighted average price of all RECs retired and ACPs made in each year, across all tiers. Note that the years shown in Figure 3 and all subsequent figures correspond to each state's definition of "compliance year" (CY), which begins on June 1 in Delaware, Illinois, New Jersey, and Pennsylvania.

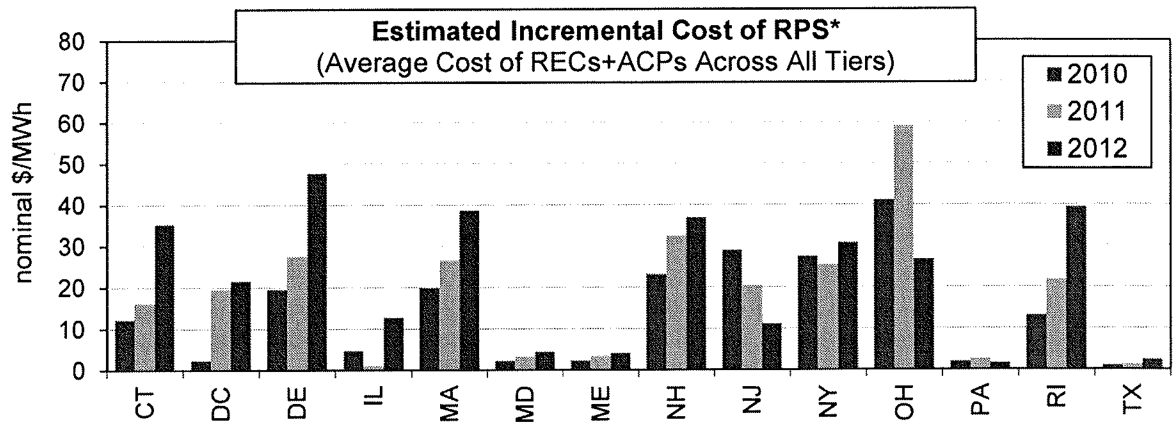
The variation in these estimated costs–ranging from well below \$10/MWh to upwards of \$60/MWh–partly reflects differences in REC and ACP prices across states and years. For example, low main-tier REC prices in Maryland, Pennsylvania, and Texas, as shown previously in Figure 2, led to correspondingly low incremental RPS costs in those states (less than \$5/MWh across the years shown). Conversely, relatively high and progressively increasing main tier REC prices among northeastern states underlie the trends in RPS incremental costs show in Figure 3.

Of some note are Ohio and Delaware, which both experienced relatively high estimated RPS costs compared to contemporaneous spot market REC prices. In the case of Ohio, the discrepancy was most pronounced in 2011 when the state's distribution utilities paid an average of \$110.55/MWh for in-state non-solar RECs (PUCO 2013a) compared to spot market prices ranging from roughly \$10-\$30/MWh and ACP rates of \$46/MWh. The PUC subsequently ruled that one of the state's utilities, FirstEnergy, substantially overpaid for RECs, and ordered the utility to refund its customers \$43.3 million for excess REC purchase costs over the 2009-2011 period (PUCO 2013b). In the case of Delaware, the state's lone distribution utility, Delmarva Power & Light, has met much of its compliance obligation with long-term bundled PPAs, and the above-market costs of those resources are greater than spot market REC prices.[24] The per-MWh compliance costs rose over the 2010-2012 period as an increasing share of the compliance obligations were met through those long-term PPAs.

Aside from differences in REC pricing, the variations in estimated incremental RPS costs shown in Figure 3 also reflect the differing mixes of resource tiers within each state's RPS. In particular, average incremental RPS costs were generally low for states with large secondary tier targets, as those tiers are typically characterized by low REC prices. The most pronounced example is Maine, where the secondary tier for existing resources constituted roughly 85-90% of the overall RPS requirement each year. Conversely, states with higher solar set-aside requirements tended to have higher incremental RPS costs, given that SREC prices have generally been relatively high compared to other tiers. For example, New Jersey and Washington, D.C. both had relatively high solar set-aside targets over the 2010-2012 period, contributing to relatively high average estimated incremental costs for the RPS as a whole, at least in some years. The decline in SREC

[24] Based on Delmarva's 2012 IRP, above-market costs for RPS contracts in 2012 were projected to be \$53/MWh for its three wind PPAs (in aggregate), \$179/MWh for the Dover SunPark solar PPA, \$241/MWh for the collection of PPAs with smaller solar projects, and \$268/MWh for the Bloom fuel cell project (Delmarva Power & Light 2012). Delmarva's RPS surcharge, which serves to recover the entirety of the above-market costs of the utility's RPS resources costs in each year, equated to an average above-market cost of \$55/MWh in 2012.

prices in most markets over the 2010-2012 period, however, tended to dampen the impact of solar requirements on overall RPS compliance costs, and in the case of New Jersey led to a marked decline in average per-MWh RPS compliance costs.



** Incremental costs are estimated from REC and ACP prices and volumes for each compliance year, which may differ from calendar years. If available, REC prices are based on average prices reported by the PUC (DC, IL, MD, ME, OH, NJ, PA); they are otherwise based on published spot market prices, supplemented with data on long-term contract prices where available. Incremental costs for NY are based on NYSERDA's annual RPS expenditures and estimated REC deliveries.*

Figure 3. Estimated incremental RPS cost over time in states with restructured markets ($/MWh of renewable electricity)

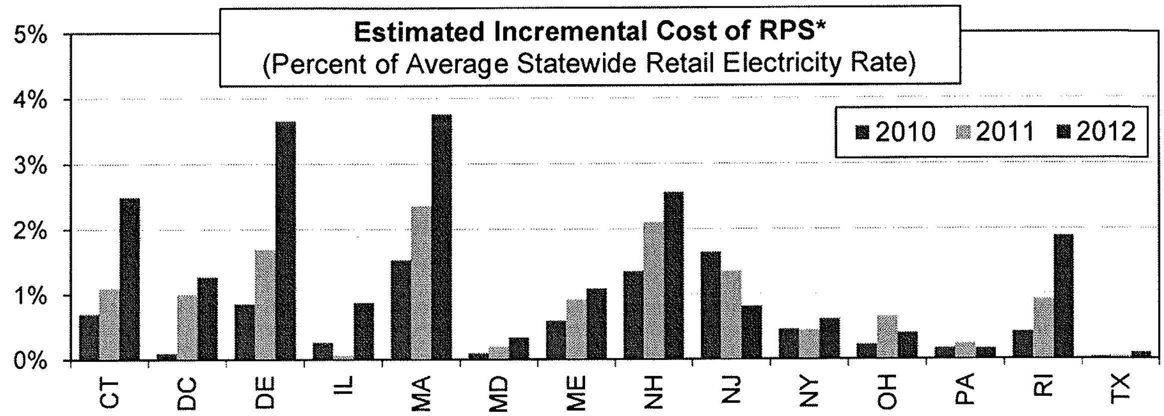
3.1.4 Estimated incremental RPS Costs as a Percentage of Retail Rates

RPS compliance costs can alternatively be expressed as a percentage of retail electricity rates, which we calculate as the ratio of the dollar value of RPS compliance costs to total revenues from retail electricity sales in each year. Unlike the data presented in the previous section, RPS compliance costs measured as a percentage of retail rates are a directly tied to the size of the target (given that higher targets, all else being equal, correspond to higher dollar costs associated with REC and ACP purchases) and are, in effect, normalized to the retail cost of electricity in each state. To reiterate, compliance costs denoted in these terms are not necessarily equivalent to actual retail rate impacts (such as for states where ACP costs are not recovered from ratepayers).

As shown in Figure 4, estimated incremental RPS costs in most states constituted less than 2% of average retail rates over the 2010-2012 period (with an average in 2012 of 1.4%).[25] Clearly though, some variation exists across states and years, with estimated costs ranging from below 0.5% of retail rates in many states up to 3-4% in Delaware and Massachusetts in 2012. That variation reflects many of the same fundamental underlying drivers discussed above (e.g., differences in REC pricing and differences in the mix of resource tiers). Variation in Figure 4 further reflects differences in the size of the RPS targets across states and over time. It is for this reason that, in most states, estimated costs increased over the period shown as the RPS percentage targets ramped up (the most notable exception being New Jersey, where the decline

[25] Several of the states included in Figure 4 have independently published their own estimates of RPS compliance costs (CEEEP and R/ECON 2011; LEI 2012; NHPUC 2011b; ME PUC 2012; ME PUC 2013; NJ BPU 2011; NYSERDA 2013b). Those analyses are often based on similar methods as used within the present study, and thus not surprisingly, the results are generally consistent.

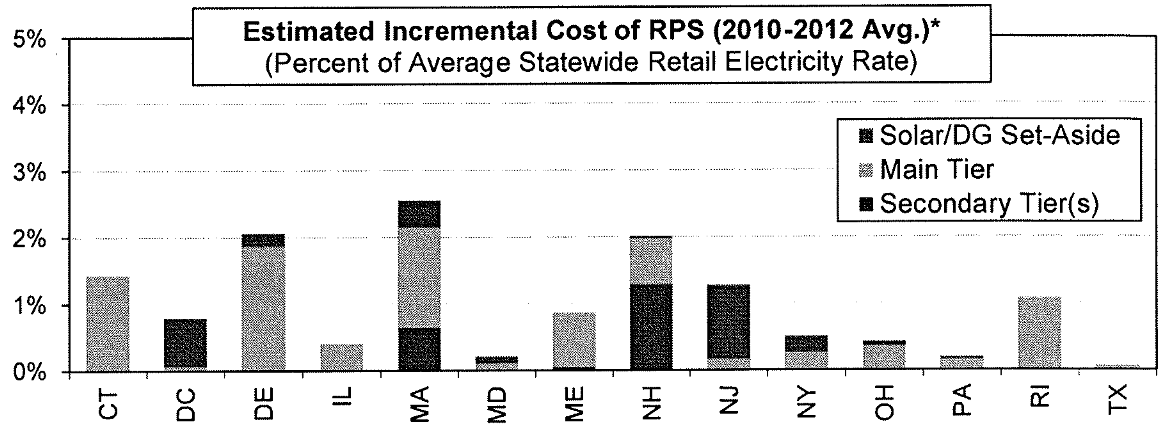
in SREC prices more than offset the impact of the increasing RPS targets). We discuss further at the end of this section some considerations related to how RPS costs may evolve going forward given continued increases in RPS targets over the next decade.



** Incremental costs are estimated from REC and ACP prices and volumes for each compliance year, which may differ from calendar years. If available, REC prices are based on average prices reported by the PUC (DC, IL, MD, ME, OH, NJ, PA); they are otherwise based on published spot market prices, supplemented with data on long-term contract prices where available. Incremental costs for NY are based on NYSERDA's annual RPS expenditures and estimated REC deliveries.*

Figure 4. Estimated incremental RPS cost over time in states with restructured markets (% of retail rates)

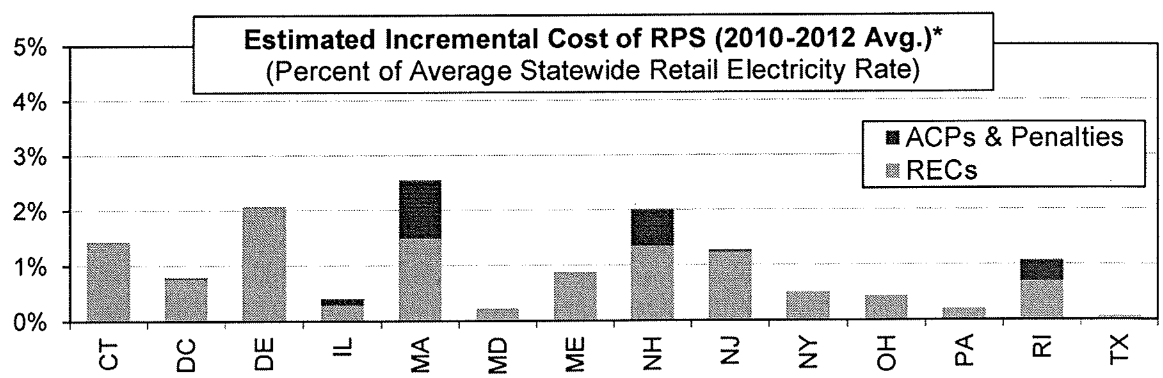
Figure 5 shows the estimated incremental cost associated with each resource tier and its relative contributions to total RPS costs in each state. These data are averaged over the 2010-2012 period in order to smooth out fluctuations associated with large swings in REC prices from year to year. For most states, main tier requirements represented the bulk of total RPS compliance costs, though a number of notable exceptions exist. In Washington, D.C. and New Jersey, which had both relatively high solar set-aside targets and relatively high SREC prices, solar set-aside costs constituted the majority of total RPS costs over 2010-2012 and were on the order of 1% of average retail electricity rates. New York's DG set-aside has similarly constitituted a large fraction, roughly 50%, of total RPS costs. In Massachusetts and New Hampshire, where shortages in the secondary tiers have led to high REC prices, the costs of the secondary tier requirements were relatively significant and, in the case of New Hampshire, represented the bulk of total RPS costs.



** Incremental costs are estimated from REC and ACP prices and volumes for each compliance year, which may differ from calendar years. If available, REC prices are based on average prices reported by the PUC (DC, IL, MD, ME, OH, NJ, PA); they are otherwise based on published spot market prices, supplemented with data on long-term contract prices where available. Incremental costs for NY are based on NYSERDA's annual RPS expenditures and estimated REC deliveries.*

Figure 5. Estimated incremental RPS cost by tier in restructured markets (% of retail rates)

RPS estimated compliance costs in most states with restructured markets consist of some combination of direct REC procurement and ACPs or penalties (which, in some cases, may be directed toward programs or funds to support renewables deployment). RPS rules in some states may prohibit or limit the ability of suppliers from passing through the cost of ACPs or penalties to ratepayers (as discussed earlier in Section 2). In most states, the majority of RPS obligations were met with RECs during the 2010-2012 period (or at least for those years with available data). As such, REC costs constituted the overwhelming bulk of total RPS costs in most states, as shown in Figure 6. The three primary exceptions are Massachusetts, New Hampshire, and Rhode Island, where significant shortages in one or more years led to a substantial quantity of ACPs.



** Incremental costs are estimated from REC and ACP prices and volumes, averaged over the 2010-2012 compliance years, based on those years for which data are available. Only 2010 data available for CT and DC. If available, REC prices are based on average prices reported by the PUC (DC, IL, MD, ME, OH, NJ, PA); they are otherwise based on published spot market prices, supplemented with data on long-term contract prices where available. For IL, ACP costs reflect the requirement that competitive suppliers must meet at least 50% of RPS target with ACPs. NY does not have ACPs or penalties; all costs are therefore associated with REC procurement and program administration.*

Figure 6. Estimated incremental RPS costs from RECs and ACPs in restructured markets (% of retail rates)

3.2 States with Regulated Markets

For states with traditionally regulated electricity markets, where RPS obligations are met principally through long-term bundled PPAs and/or utility-owned renewable generation, states and utilities estimate the incremental RPS costs by comparing the gross cost of RPS resources procured against the counterfactual cost of resources that would have been procured but for the RPS. As discussed in Section 2, states and utilities can, and have, employed a variety of methods to estimate incremental RPS compliance costs in regulated RPS states. We have not developed independent cost estimates, but rather, have synthesized estimates published by utilities and regulators in regulated RPS states, and have translated those data into a common set of metrics for comparison.

In particular, we summarize incremental RPS compliance cost estimates for eleven regulated states where sufficient data were available. For California, two separate estimates are presented based on different underlying methodologies, and those results are summarized and discussed separately in Text Box 3. Although the focus throughout the section is on incremental costs, we present data on gross compliance cost estimates for two states (Kansas and Nevada) where data on incremental costs are unavailable (Text Box 4).

3.2.1 Methodology and Data Sources

The specific RPS cost studies synthesized for this report are listed in Table 6. For most traditionally regulated states, the cost data are derived primarily from utility compliance reports where RPS compliance costs are reported *ex post,* in some cases for ratemaking purposes and/or to demonstrate compliance with any applicable cost caps. For New Mexico, the RPS cost data are instead based on prospective cost estimates from annual procurement plans, while data for California and Wisconsin are based on estimates developed or published by the state PUC. In general, the cost data are limited to IOUs, either because only those entities are subject to the RPS or because only those entities issue public compliance reports, though the data for Minnesota, North Carolina, Washington, and Wisconsin also include publically owned utilities with RPS obligations.

Table 6 also highlights several important caveats and complexities. First, incremental cost data are wholly unavailable for a number of regulated RPS states (Hawaii, Iowa, Kansas, Montana, and Nevada; see the Appendix for discussions of available cost data for those states) or are available for only a subset of utilities or years. Second, although we present data on a statewide basis, estimated costs for individual utilities may differ from the statewide average. Where possible, we note within the text where variations among utilities in a given state are particularly significant. Third, the methods and conventions used by utilities and regulators when estimating incremental RPS costs vary considerably (and are often not completely transparent). The comparisons across states are thus necessarily imperfect, though to the extent possible, we discuss qualitatively how methodological differences may impact the results. Finally, there are often disconnects in regulated states between the timing of RPS obligations and when costs are incurred. For example, utilities often procure renewable resources in advance of their compliance obligations, and some utilities provide up-front incentives for renewable DG (in effect, providing an up-front payment for RECs generated over the lifetime of the systems). In general, the data we report represent estimated costs incurred by utilities in each year and therefore correspond to actual renewable energy procurement in that year. For several states, though, the data instead represent the estimated incremental cost of renewable energy applied towards the requirement in each year (which may differ both in quantity and in the underlying resources from the renewable energy procured in the same year). These differences in accounting methods are noted within the text, where relevant.

Table 6. Data Sources Used to Calculate Estimated RPS Compliance Costs for Regulated States

State	Data Source*	Coverage	Methodology and Key Conventions
AZ	Utility compliance reports	IOUs (2010-2012)	Incremental costs as a percent of retail rates calculated from IOUs' annual RPS expenditures, consisting of administrative costs, above-market costs for utility-scale RE, and DG incentive program costs; excludes committed (but not yet spent) incentives
CA	CPUC Section 910 report	IOUs (2011 only)	Two alternative methods used: Proxy generator (levelized cost of CCGT) and market prices (see Text Box 3)
CO	Utility compliance reports	PSCo (2010-2012)	Modeling: PSCo compares system wide costs with and without post-2006 RPS resources
MI	Utility compliance reports	Detroit Edison, Consumers Energy, Wisconsin Electric, Alpena (2010-2012)	Hybrid approach: avoided energy costs based on projected market prices (DTE) or modeling (Consumers); avoided capacity costs based on proxy generator (CT)
MN	Utility rate impact reports	Great River, Minnesota Power, Minnkota, MMPA, Missouri River, SMMPA, Otter Tail (2010 only)	Market prices: compare PPA prices to MISO LMPs; significant methodological variations**
MO	Utility compliance reports and plans	IOUs (2011-2012)	Costs based on only solar REC and solar rebate costs; no non-solar compliance costs***
NC	Utility compliance reports	Varies by year****	Hybrid approach: avoided energy costs based on modeling and avoided capacity costs based on proxy generator (CT).
NM	Utility procurement plans and compliance reports	SPS (2010-2012) PNM (2010 and 2012 only)	SPS: Modeling for avoided energy costs, proxy generator (CT) for avoided capacity costs; and REC prices. PNM: Modeling for avoided fuel costs; no avoided capacity costs included
OR	Utility compliance reports	PGE and PacifiCorp (2011/2012 only)	Proxy generator (levelized cost of CCGT)
WA	IOU compliance reports and I-937 filings with WA Dept. of Commerce	Statewide (2012 only)	Market prices: Most utilities compare RPS resource revenue requirements to market prices; significant methodological variation
WI	Wisconsin Public Service Commission RPS cost report	Statewide (2010 only)	Market prices: Compares levelized cost of new renewable generation built/procured over the 2006-2010 period to MISO LMPs

* Data Sources: AZ (APS 2011, 2012, 2013; TEP 2011, 2012, 2013; UNS 2011, 2012, 2013), CA (CPUC 2013a), CO (PSCO 2013a), MI (DTE 2011, 2012, 2013a; Consumers 2011, 2012, 2013a; Wisconsin Electric 2011, 2012, 2013; Alpena 2011, 2012, 2013), MN (Great River 2011, Minnesota Power 2011, SMMPA 2011, Minnkota 2011, MMPA 2011, Missouri River Energy Services 2011, Otter Tail 2011), MO (Ameren Missouri 2013b; KCPL 2012, 2013; KCPL GMO 2012, 2013), NC (Dominion 2012, 2013; Duke 2012, 2013; GreenCo 2012; NCEMPA 2011, 2012, 2013; NCMPA1 2011, 2012, 2013; Progress Energy Carolinas 2011, 2012, 2013; Halifax 2013; Town of Winterville 2013; Town of Fountain 2013), NM (SPS 2009, 2012, 2013; PNM 2009 and 2013b), OR (PGE 2011, 2012, 2013; Pacific Power 2011, 2012, 2013b), WA (Avista 2013; PacifiCorp 2013b; PSE 2013; WDOC 2013), WI (WPSC 2012)

** For example, some utilities include capacity credits, curtailment costs, transmission costs, and/or financial transmission rights costs/revenues; some use hourly LMPs, while others use average peak and off-peak prices; most consider only post-2006 renewables.

*** For MO, compliance costs were calculated from data provided in the compliance plans and reports, rather than using the reported "rate impacts", which could not be readily compared within the summary figures in this report. In performing these calculations, compliance costs associated with the non-solar requirements in 2011 and 2012 were assumed to be zero, as those obligations were met entirely with pre-existing renewables procured prior to enactment of the RPS.

**** Depending on the year, a different set of utilities included data on incremental compliance costs within their annual filings. The state's largest utility, Progress Energy, included such data in all years. The state's other IOUs, Duke Energy and Dominion, included incremental cost data for 2011 and 2012, as did a number of smaller publically owned utilities.

3.2.2 Estimated incremental RPS Costs per Unit of Renewable Generation

Figure 7 presents estimated incremental cost data in terms of $/MWh of renewable energy procured, focusing on resources procured for each state's *general RPS obligations* (that is, excluding any solar or DG set-aside).[26] These data are, in effect, the average estimated above-market cost (i.e., implicit REC price) of the various contracts and projects procured for general RPS obligations in each state, based on the particular methodology used by the reporting entity. This information was available for only seven states, including California, which is discussed separately in Text Box 3.

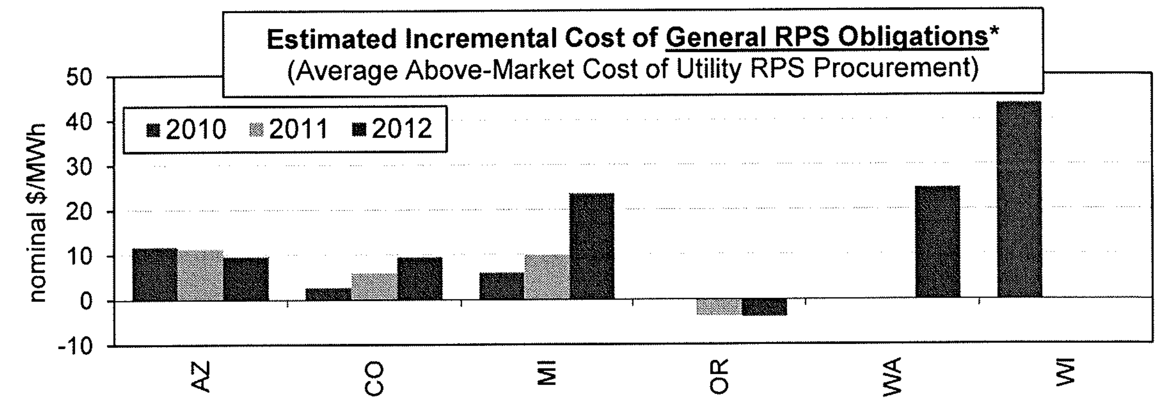
Among the six states in Figure 7, average estimated incremental costs were generally near or below roughly $20/MWh. Incremental costs in Wisconsin were somewhat higher ($44/MWh) for the single year available (2010). As noted in Table 6, the Wisconsin PSC estimated compliance costs using historical Midwest energy spot market prices as the basis for avoided costs, and those market prices were particularly depressed in 2010 as a result of the economic downturn (WI PSC 2012). At the opposite end of the spectrum is Oregon, where average utility estimates of incremental compliance costs were actually negative for the years shown; that is, RPS resources were determined to cost less, on a statewide average basis, than the proxy non-renewable resources that would have otherwise been procured.[27] In part, this reflects the integrated resource planning process in the state, through which the state's two large IOUs have procured cost-effective renewable resources on economic grounds, as well as opportunistic purchases of low-cost unbundled RECs.[28]

The variation in estimated costs observed in Figure 7 reflects a number of considerations. Although most of the states shown have relied primarily on wind power to meet general RPS obligations, wind energy costs vary across states and regions (e.g., due to differences in wind speeds and the vintage of wind projects installed). The cost of non-renewable power, which forms the basis for the avoided cost of renewable energy, also varies regionally, depending on the fuel mix, market structure, and other factors.

Methodological differences also undoubtedly play some role. In particular, reliance upon wholesale electricity market prices as the reference point for estimating incremental RPS costs (i.e., the approach used in Washington and Wisconsin) may capture fewer sources of avoided cost than the other approaches used, thereby resulting in somewhat higher RPS compliance cost estimates. At a minimum, reliance upon historical wholesale market prices as the basis for avoided costs can yield volatile results, given potentially wide fluctuations in wholesale electricity market prices from year-to-year. This is illustrated by the data for Wisconsin, where the PSC estimated RPS compliance costs for 2008 (which is outside our period of analysis and

[26] We focus here on general RPS obligations because of the complications associated with calculating the incremental cost of DG set-asides in $/MWh terms and lack of the requisite data. DG set-aside costs are, however, included in subsequent figures where RPS costs are presented as a percentage of average retail rates.
[27] Of the two utilities with compliance obligations in 2011-2012, only PacifiCorp estimated net cost savings from its RPS resources, while Portland General Electric estimated a slight increase in revenue requirements.
[28] The IOUs are allowed to meet up to 20% of their RPS obligation in each year with unbundled RECs.

thus not included in Figure 7) to be considerably lower than in 2010 ($27/MWh in 2008 vs. $44/MWh in 2010), as a result of higher wholesale electricity market prices in 2008.



** Incremental cost of general RPS obligations (i.e., RPS obligations excluding any set-asides) are based on utility- or PUC-reported estimates. Data for AZ and CO are based only on the single largest utility in each state (APS and PSCo, respectively). States omitted if data on the incremental costs of general RPS obligations are unavailable (HI, IA, KS, MT, NV) or if available data cannot be translated into the requisite form for this figure (MN, NC, NM, MO). See Text Box 3 for data on CA.*

Figure 7. Estimated incremental RPS cost over time for general RPS obligations in regulated states ($/MWh of renewable electricity)

3.2.3 Estimated incremental RPS Cost as a Percentage of Retail Rate

Estimated incremental costs are presented as a percentage of average retail rates in Figure 8, which includes a larger set of states than in the prior figure, as a result of greater data availability. As explained previously, these data essentially represent the dollar value of annual estimated compliance costs as a percentage of total retail electricity costs. Again, comparability across states is somewhat limited by the differences in methods and conventions used by the utilities and regulators that developed these cost estimates.

As shown on the left-hand side of Figure 8, estimated RPS costs during 2010-2012 were generally at or below 2% of average retail rates for many states, though these costs span a wide range. At the low end is Oregon, where estimated incremental RPS costs were negative, as discussed above. Estimated compliance costs in Missouri were also quite low, on account of the fact that the state's utilities were able to meet the entirety of their non-solar obligations in 2011 and 2012 with banked RECs from renewable resources procured prior to enactment of the RPS (and which thus entail no incremental compliance costs). Thus the data in Figure 8 represent solely the estimated cost of solar REC purchases and solar rebates issued for compliance with the state's solar set-aside. Note that for both Oregon and Missouri, the data are based on the estimated incremental cost of resources applied towards the RPS requirement in the years shown, but utilities in these states procured substantially greater amounts of renewables, banking the excess for compliance in future years.[29]

[29] Data on the incremental cost of the renewable energy procured in each year are not available for Oregon or Missouri, but the available information suggests that those costs could, at least for some utilities, be less than the amounts shown in Figure 8, even though they would be based on a larger volume of renewable energy. In Missouri, for example, both KCP&L and KCP&L GMO indicated that "all non-solar renewable additions caused revenue

At the opposite end are Arizona, Colorado, and New Mexico, where statewide average estimated incremental costs ranged from 3-4% of average retail rates in most years. Higher estimated RPS costs in those states are associated with several factors. To a significant degree, they can be attributed to DG and/or solar set-aside requirements in those states, which, as shown on the right-hand side of Figure 8, constituted the bulk of total estimated RPS compliance costs in most years. Important to understand, however, is that the apparently high cost of the DG set-asides is partially due to the fact that the costs are heavily front-loaded: rebates and performance-based incentives are paid upfront (or over several initial years of production) in exchange for RECs delivered over each DG system's lifetime. Those costs have declined somewhat over time, though, as utilities in these states have reduced incentive levels and moved away from upfront rebates. In addition to the impact of the DG set-aside, RPS costs in Colorado are also relatively high, owing to the fact that Colorado's RPS procurement levels were substantially higher than other states shown in Figure 8. In particular, the state's largest utility, Xcel Energy, attained renewable procurement levels equal to 15% to 22% of retail sales over the 2010-2012 period, compared to renewables procurement levels of 5-10% in most of the other states in Figure 8.[30] For Arizona, an additional factor contributing to the relatively high estimated incremental RPS costs in Figure 8 is that those data include administrative expenses (unlike in most other states), which add roughly 10% to total RPS costs for the years shown.

Importantly, the statewide averages presented in Figure 8 may mask variability in RPS costs among utilities within some states. In Washington, for example, all three IOUs as well as the state's largest municipal utility reported costs for 2012 on the order of 0.5-1.4% of retail rates, but many of the smaller publically owned utilities reported higher costs (in several cases as high as 8-9%). Substantial variability was also evident among Minnesota utilities, which reported RPS costs in 2010 ranging from 0.1%-8.6% of average retail rates (though most were within the range of 1-3%). For New Mexico, the statewide averages are based on only two utilities (PNM and SPS), but those utilities reported divergent costs for 2012: 1.9% for PNM vs. 4.4% for SPS. In general, this intra-state variability is rooted in many of the same factors that drive differences in RPS costs across states – e.g., differences in procurement levels, resource costs, and cost calculation methodologies – though teasing out the relative significance of these underlying drivers is typically not feasible.

Unlike restructured markets, where compliance is often enforced through ACP mechanisms, RPS targets in regulated states are generally enforced through the potential for the PUC to assess penalties. Although utilities in regulated states have occasionally been subject to administrative penalties for RPS non-compliance, no significant penalties were levied over the 2010-2012 period in any of the states listed in Figure 8. Thus, the entirety of the costs shown consists of costs associated with renewable electricity purchases.

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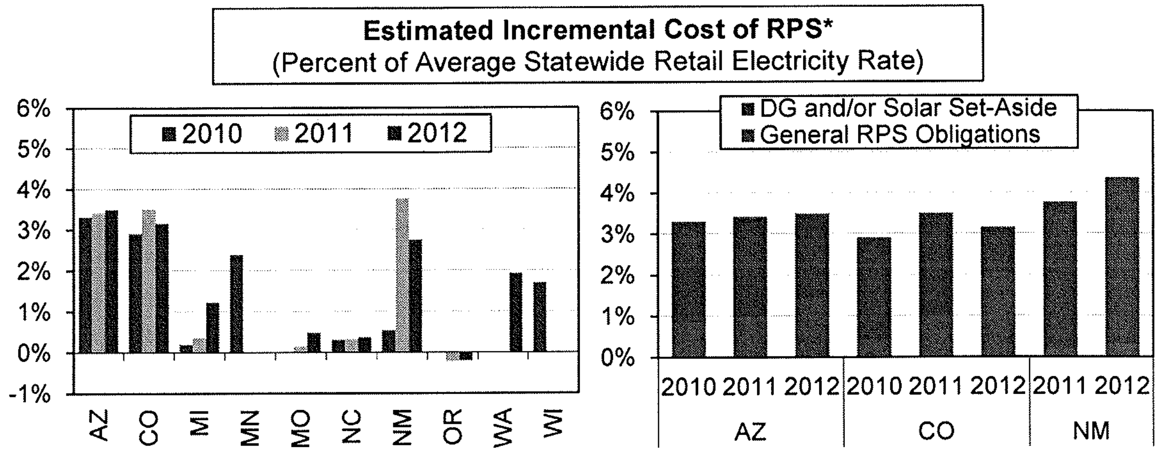
requirements to decrease" (KCPL 2013; KCPL GMO 2013); including those resources in the cost calculations would therefore reduce the estimated rate impact.

[30] Incidentally, Xcel's renewable energy procurement well-exceeded its RPS targets over the 2010-2012, which ranged from 5-12% of retail sales. Thus, the company's RPS costs for those years includes costs associated with renewable energy credits that were banked for use in subsequent CYs, thus potentially reducing RPS procurement costs in those future years.



** Incremental costs are based on utility- or PUC-reported estimates and are based on either RPS resources procured or RPS resources applied to the target in each year. Data for AZ include administrative costs, which are grouped in "General RPS Obligations" in the right-hand figure. Data for CO are for Xcel only. Data for NM in the left-hand figure include SPS (2010-2012) and PNM (2010 and 2012), but include only SPS in the right-hand figure. States omitted if data on RPS incremental costs are unavailable (HI, IA, KS, MT, NV).*

Figure 8. Estimated incremental RPS cost over time in regulated states (% of retail rates)

Text Box 3. Estimated incremental RPS Costs in California

The California PUC has issued several reports related to the cost of the state's RPS. The March 2013 report, entitled *Report to the Legislature in Compliance with Public Utilities Code Section 910*, provided data on gross RPS expenditures for each of the state's three IOUs, along with two sets of avoided cost estimates that can be used to compute incremental costs (i.e., gross costs minus avoided costs). One set of avoided cost estimates are based on the state's MPR, which is intended to estimate the all-in cost of a CCGT and is used by the CPUC as a proxy for long-term electricity market prices when calculating the above-market costs of individual RPS contracts. The other set of avoided cost estimates, which were provided by the utilities, are based on day-ahead CAISO energy market prices and the cost of capacity in the CAISO market.

As shown below, these alternate avoided cost estimates yield dramatically different results when used to calculate incremental RPS costs. Relative to the MPR, the estimated incremental cost of the RPS in 2011 was negative (i.e., the RPS yielded net cost savings), equal to -$24/MWh of renewable energy procured or -3.6% of average retail rates. In contrast, relative to short-term market prices, estimated incremental RPS costs in 2011 were equivalent to $43/MWh or 6.5% of average retail rates. At a minimum, these results clearly demonstrate the importance of assumptions about the costs avoided through increasing the use of renewable energy.

Table 7. Alternate RPS Incremental Cost Estimates for California (2011)

	RPS Procurement (% of Retail Sales)	**Estimated Incremental Costs Calculated using MPR as Avoided Cost**		**Estimated Incremental Costs Calculated using Spot Market Prices as Avoided Cost**	
		$/MWh	**% of Retail Rates**	**$/MWh**	**% of Retail Rates**
PG&E	20%	-28	-4.0%	36	5.2%
SCE	21%	-14	-2.3%	53	8.6%
SDG&E	21%	-49	-7.6%	22	3.4%
Average	**20%**	**-24**	**-3.6%**	**43**	**6.5%**

Text Box 4. Gross RPS Compliance Costs in Kansas and Nevada

Only gross RPS compliance costs have been reported for Kansas and Nevada. In Kansas, the utilities submit annual filings to the KCC, reporting the gross revenue requirements of their renewable energy procurement. Those cost data are confidential, but the KCC issues a public summary report that aggregates the data across utilities, and reports gross revenue requirements of renewable purchases per kWh of retail sales. In its report for the 2012 compliance year, the KCC found that the gross statewide costs of all renewable purchases constituted an average of 0.16 cents/kWh of retail sales, which equates to 1.7% of statewide average retail rates in that year (KCC 2013).

In Nevada, the state's two IOUs include estimates in their annual RPS compliance reports for gross RPS expenditures, consisting of the cost of purchased power, RECs, incentives and rebate programs. For 2013, these costs were estimated at $273 million and $139 million, for Nevada Power and Sierra Pacific, respectively, which equates to an average gross cost per unit of renewable energy of approximately $64/MWh across the two utilities (NV Energy 2013). For reference, we estimate incremental RPS costs using the utilities' published long-term avoided cost rate, which in their 2012 integrated resource plan was equal to $30/MWh (NV Energy 2012). Using that value, we estimate average incremental RPS cost to be equal to roughly $34/MWh of renewable energy procured, or 8% of average retail rates.

3.3 RPS Surcharges

RPS costs may be recovered from ratepayers through a dedicated surcharge or tariff rider (i.e., a "line-item" on the customer's bill), often adjusted periodically and subject to review and approval by the PUC. In contrast to the preceding RPS compliance cost data, which represent the incremental costs borne by utilities or LSEs, surcharges represent the incremental costs borne directly by customers. As demonstrated and discussed below, the costs passed through to customers via RPS surcharges may differ from the compliance costs borne by the utility. This can occur for any number of reasons, including, for example, discrepancies between estimated and actual costs, limitations on the recovery of ACP costs, and statutory caps on the surcharge.

Line-item surcharges on customer bills are currently used to recover RPS compliance costs in eight states (Arizona[31], Colorado, Delaware, Michigan, North Carolina, New York, Ohio, and Rhode Island), though in some cases only by a subset of utilities or LSEs.[32] These surcharges are denominated in various ways: as volumetric $/kWh charges in Arizona, Delaware, Ohio, New York, and Rhode Island; as a percentage of the total bill in Colorado, and as fixed monthly

[31] Arizona Public Service is in the process of transitioning the cost of utility-owned renewable resources developed through the AZ Sun Program into its rate base. Thus, going forward, the RPS surcharge will no longer represent the totality of RPS-related costs borne by ratepayers, as some of those costs will be embedded in base rates.

[32] A number of other states, including New Mexico, use surcharges to recover only a subset of RPS compliance costs, while other costs are recovered through base rates or through broader fuel adjustment surcharges that include non-renewable resource costs. Within this section, however, we focus only on states where RPS-specific surcharges are used to recover the entirety of RPS compliance costs.

customer charges in Michigan and North Carolina. For ease of comparison, Table 8 compares utility-specific surcharges in 2012, for residential customers specifically, translated into units of dollars-per-customer-per-month ($/customer-month).[33] As shown, residential surcharges ranged from roughly $0.50/month or less for some utilities to $3-4/month for many others.

Table 8. Average RPS Surcharges for Residential Customers in 2012

State	Utility	2012 Surcharge ($/customer-mo.)*
AZ	Arizona Public Service**	$3.84
	Tucson Electric Power	$3.15
	UNSE/Citizens	$4.50
CO	Public Service Colorado (Xcel)	$1.44
	Black Hills Energy	$2.04
DE	Delmarva Power & Light	$4.29
MI	Detroit Edison Co.	$3.00
	Consumers Energy Inc.	$0.52
	Indiana Michigan	$0.07
	Wisconsin Electric Co.	$3.00
	Alpena Power	$0.24
NC	Progress	$0.56
	Duke	$0.49
NY	Central Hudson	$2.02
	Consolidated Edison	$1.07
	Orange and Rockland	$1.86
	New York State Electric & Gas	$1.64
	Niagara Mohawk	$1.92
	Rochester Gas & Electric	$1.85
OH	Cleveland Electric Illuminating (FirstEnergy)	$3.25
	Dayton Power & Light	$0.59
	Ohio Edison (FirstEnergy)	$2.49
	Toledo Edison (FirstEnergy)	$3.02
RI	Narragansett Electric**	$1.08

* Data Sources: AZ (ACC 2012a; ACC 2012b; ACC 2012c), CO (PSCO 2013a; Black Hills 2013), DE (DPL 2012a), MI (MPSC 2013), NC (NC PUC 2012), NY (NY PSC 2014), OH (DP&L 2011; Ohio Edison 2011; Cleveland Electric Illuminating Co. 2011; Toledo Edison Company 2011), RI (RI PUC 2013).
** For Arizona Public Service, we show the surcharge level in effect during the first six months of the year; the surcharge was subsequently lowered when a portion of the costs of utility-owned renewables were moved into the rate base. Narragansett Electric also revised its surcharges mid-year; we show the weighted average surcharge for the calendar year.

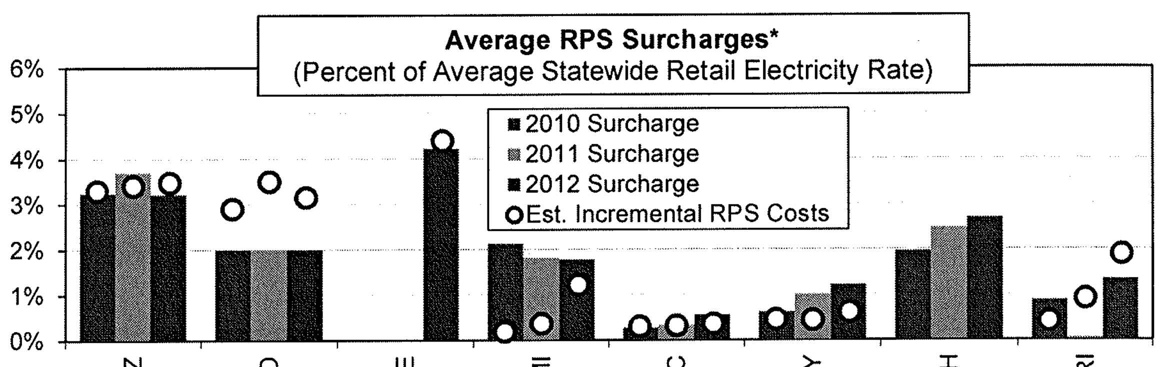
Statewide average RPS surcharges across all customer classes over the 2010-2012 period are summarized in Figure 9 and expressed as a percentage of average statewide retail electricity rates. As shown, surcharges ranged from less than 1% of average retail rates in a number of states (North Carolina, Ohio, and Rhode Island) to roughly 4% in Delaware, reflecting many of

[33] For those states where some translation to these units was performed, we did so using EIA data for residential customer count, revenues, and sales by utility (EIA 2013).

the same drivers discussed previously–e.g., differences in the size of the targets, cost of resources procured, and reliance upon front-loaded incentives for solar or DG rebates.

Importantly, RPS surcharge costs borne by customers may, and often do, differ from the estimated incremental RPS costs borne by utilities or other LSEs. This can be seen in Figure 9 by comparing the average surcharges to the estimated incremental RPS costs for the corresponding years (which correspond in most cases to the data presented earlier in Figure 3 for restructured markets and in Figure 8 for regulated states).[34] In Colorado–where, not incidentally, the state's largest utility has well-surpassed its RPS targets–estimated utility compliance costs exceeded average surcharge collections in each year of the period shown. The RPS surcharge in Colorado is capped at 2%, and utilities may carry forward any deficit to be collected in future years. Similarly, in Rhode Island, the average customer surcharge in 2011 represented just 0.05% of retail rates, compared to estimated utility costs of roughly 1% of retail rates; this mismatch was the result of a true-up associated with over-charges in the previous year.

In other states, the converse has occurred, where surcharge collections have exceeded utility compliance costs. This was the case in Michigan over the entirety of the 2010-2012 period, where utility compliance costs ranged from 0.2% to 1.2% of retail rates, but surcharges averaged roughly 2% of retail rates in each year. The surcharges levied by the state's two large IOUs are based on projected long-term annual average RPS compliance costs; in effect, the utilities plan to over-collect in early years and under-collect in later years, in order to smooth out the rate impacts of RPS compliance over time. Notably, however, both utilities requested significant reductions for their surcharges for 2013, with Detroit Edison proposing a reduction in its residential surcharge from $3.00 to $0.43 per month, and Consumers Energy proposed to eliminate its residential surcharge.



** Surcharge data represent statewide averages for investor-owned utilities (AZ, CO, DE, MI, NC, NY) or default service providers (OH, RI). The DE surcharge commenced in 2012. Incremental RPS Costs represent compliance costs and generally correspond to the values presented previously in Figure 3 and Figure 8 . Incremental RPS cost data for OH are omitted from this figure, as the surcharges apply only to First Energy and Dayton Power & Light, and comparable cost data are not available.*

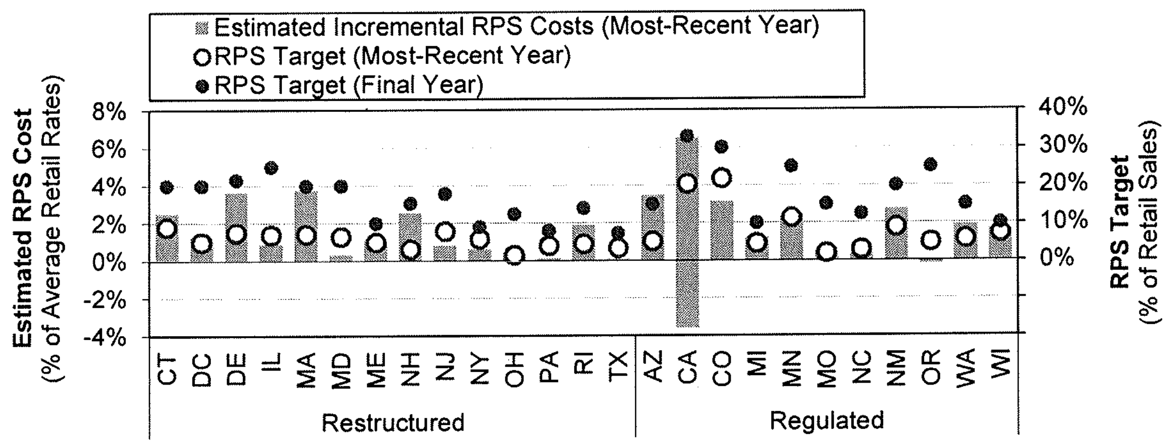
Figure 9. RPS surcharges over time (% of retail rates)

[34] Incremental RPS cost data for Ohio are omitted from Figure 9 as the surcharges apply only to a subset of utilities (First Energy and Dayton Power & Light) and comparable cost data are not available for those particular utilities.

3.4 Assessment of Future RPS Costs and Cost Containment Mechanisms

Estimated RPS compliance costs over our historical period of analysis are a function partly of the RPS targets applicable during those years. As shown in Figure 10, which summarizes estimated RPS compliance cost data for the most-recent historical year available for each state, the corresponding RPS targets or procurement levels in those years (i.e., the open circles within the figure) ranged from 2% to 22% of retail sales, but in most cases were within a band of 4-8% (excluding secondary tiers).[35]

Though there is certainly some relationship between the stringency of the target or procurement level and the magnitude of estimated compliance costs (e.g., Colorado had relatively high RPS procurement levels and high costs, while Ohio had a correspondingly low RPS target and low costs), a variety of other conditions have also strongly impacted compliance costs. As discussed previously, such factors include–among other things–regional REC supply/demand balance, the presence of solar or DG set-asides, and the cost calculation methodology, itself.



** For most states shown, the most-recent year RPS cost and target data are for 2012; exceptions are CA (2011), MN (2010), and WI (2010). MA does not have single terminal year for its RPS; the final-year target shown is based on 2020. For CA, high and low cost estimates are shown, reflecting the altemate methodologies employed by the CPUC and utilities. Excluded from the chart are those states without available data on historical incremental RPS costs (KS, HI, IA, MT, NV). The values shown for RPS targets exclude any secondary RPS tiers (e.g., for pre-existing resources). For most regulated states, RPS targets shown for the most-recent historical year represent actual RPS procurement percentages in those years, but for MO and OR represent REC retirements (for consistency with the cost data).*

Figure 10. Estimated incremental RPS costs compared to recent and future RPS targets

Over the 2010-2012 period, average estimated RPS compliance costs in the United States were equivalent to 0.9% of retail electricity rates when calculated as a weighted-average (based on

[35] The open circles in Figure 10 represent somewhat different things depending on the state, and are intended to be consistent with the corresponding cost data. For restructured states, the open circles represent RPS targets, as the costs are based on the total volume of REC purchases and ACPs. For most regulated states, the cost data represent the cost of RPS-eligible procurement (sometimes excluding pre-existing RPS resources), and thus the open circles represent the corresponding quantity of RPS-eligible resources procured. For two regulated states, Oregon and Missouri, the cost data are instead based on only the cost of renewable energy applied towards the target, and thus the open circles represent the corresponding quantity of renewable energy.

revenues from retail electricity sales in each RPS state) or 1.2% when calculated as a simple average, although substantial variation exists around the averages, both from year-to-year and across states.[36] Going forward, RPS targets will rise, reaching their peak in most states within the 2020-2025 timeframe. These final-year targets, also shown in Figure 10 (the closed circles), rise to anywhere from 7% to 33% of retail sales, but in most cases to at least 15%. Compared to the RPS targets or procurement levels for the most recent historical year, the final-year RPS targets constitute, on average, roughly a three-fold increase in RPS obligations. All else remaining constant, one would expect RPS costs, in absolute dollar terms, to rise as additional renewable generation is added to meet the higher final targets set by existing policies.

Whether and the extent to which RPS compliance costs increase over time will, of course, depend on a great many factors. First and foremost, perhaps, is the underlying cost of renewable energy technologies, and whether they continue to decline as they have in recent years. Second is the price of natural gas, as gas-fired electricity is generally the baseline against which market-based REC prices or the calculated above-market costs of renewables are established. Third, RPS costs may be significantly impacted by changes to state and federal tax incentives for renewables–in particular, the federal production tax credit (PTC), which (as of this writing) expired at the end of 2013, and the federal investment tax credit (ITC), which is scheduled to decline from 30% to 10% in 2017–as these tax incentives reduce the costs borne directly by utilities. Fourth, environmental policies related to the power sector, such as federal greenhouse gas regulations and air pollution regulations, could have a significant impact on RPS costs, by raising the cost of non-renewable resources and thereby reducing the incremental cost of renewables. And finally, future RPS costs could potentially be affected–in particular, constrained–by cost containment mechanisms built into many state RPS policies, which, if they became binding, would also limit achievement of the RPS targets.

To gauge the potential trajectory of future RPS compliance costs, one can look to the various prospective RPS cost studies that have been conducted for individual states or utilities. An earlier meta-analysis by Chen et al. (2007) synthesized the results of 28 distinct state or utility-level RPS cost impact analyses, finding that 70% of the studies in their sample projected retail electricity rate increases of no greater than 1% in the year that each modeled RPS policy reaches its peak percentage target. Five of the studies projected net reductions in retail rates, while two studies projected rate impacts greater than 5%. Much has changed on the RPS landscape since the time of that study, however, as many states have increased their RPS targets and/or added set-aside provisions, and renewable energy technology costs have fallen significantly while natural gas prices have simultaneously declined.

More-recent prospective RPS cost analyses have estimated rate impacts in the final target year equal to roughly: 10% in California (CPUC 2009), 2.2-4.8% in Connecticut (CEEEP and R/ECON 2011), 7.9% in Delaware (Delmarva Power & Light 2012), 1.1-2.6% in Maine (LEI 2012), 0.3-1.7% for Northern States Power in Minnesota (Xcel Energy 2011), 2.2% for Great River Energy in Minnesota (Great River Energy 2011), and a 0.5% reduction in North Carolina

[36] California is excluded from the calculation of this average, given the lack of a single point estimate.

(RTI International 2013).[37] As with retrospective RPS cost analyses, the scope, methodology, and assumptions also vary widely among prospective cost studies, limiting their comparability to one another and to the historical cost data presented earlier. They nevertheless provide an illustrative range when considering how RPS costs may evolve as the targets rise.

3.4.1 RPS Cost Containment Mechanisms

Given the inherent uncertainty in future RPS costs, and the desire among policymakers to limit the potential burden to ratepayers, most RPS policies include one or more cost containment mechanisms or "off-ramps" (see Table 9). Various approaches are used, though the most common are ACPs and rate impact/revenue requirement caps.

- *ACPs.* Typical of restructured markets, ACPs function as a backstop compliance option for LSEs. As such, they effectively cap REC prices and thus RPS compliance costs (though exceptions may exist, as discussed below).
- *Rate impact/revenue requirement caps.* Many states cap RPS costs in terms of a maximum allowed percentage of revenue requirements, costs, or customer bills. This kind of mechanism is most common among regulated states, though is also employed in several restructured markets, in conjunction with ACPs. Caps generally apply to incremental RPS costs (though one state, Kansas, applies its cap to gross procurement costs), with varying methods used to calculate the cost of RPS resources and avoided non-renewable resources.
- *Surcharge caps.* Two states, Michigan and North Carolina, have statutory caps on RPS surcharges, denominated in terms of a maximum dollar cost per customer. In addition, Colorado has a statutory rate impact cap of 2%, but the PUC has, in effect, operationalized this as a surcharge cap, allowing the utilities to incur costs beyond the cap and defer the balance.
- *Renewable energy contract price caps.* Caps may be placed on individual RPS contract prices–as in Montana, where RPS contract prices are capped based on the avoided costs of an equivalent non-renewable resource.

[37] For California, the estimated rate impact represents the projected increase in electricity costs to meet a 33% RPS in 2020 relative to a scenario in which gas-fired generation is used to meet all new resource needs. For Connecticut, the range in estimated rate impacts corresponds to varying REC price assumptions and represents the projected cost in 2020, relative to a scenario in which RPS targets are held constant at 2010 levels. For Delaware, the rate impact estimate is for the 2022/2023 CY rather than the final RPS target year (2025/2026). For Maine, the range in estimated rate impacts corresponds to varying REC price assumptions. For Xcel, the rate impact estimates represent the incremental cost of the company's RES compliance plan in 2020, relative to an otherwise least-cost plan, across several scenarios. For Great River Energy, the rate impact estimate represents the net present value of the increase in revenue requirements over the 2013-2027 period, rather than the impact in the final target year, and furthermore represent the percentage increase in wholesale prices to the company's distribution utility customers. For North Carolina, the rate impact estimate represents the projected incremental costs in 2021 of the state's RPS and other "clean energy policies"; the net cost savings are largely attributable to energy efficiency savings used to meet a portion of the RPS requirements. In addition to the set of studies listed above, NYSERDA conducted a recent RPS evaluation, estimating that, for the 2002-2037 period, the state's current RPS portfolio would yield a slight reduction in average retail rates, with wholesale market price reduction benefits more than offsetting REC purchase costs (NYSERDA 2013b).

- *Renewable energy funding caps.* Where specific programs are established for the purpose of RPS procurement (e.g., New York), cost containment may occur through statutory or regulatory limits on program budgets.
- *Financial penalties.* Texas has a pre-specified penalty that can function largely like an ACP in terms of its containment of REC prices and incremental RPS costs. Other states may also levy financial penalties for non-compliance, but often either those penalties cannot be passed through to ratepayers and/or the penalty rate is not pre-specified, and thus they do not function as a cost containment mechanism, per se.

Aside from cost containment mechanisms with some prescribed numerical limit, such as those listed above, regulators in many states often have some level of discretionary power to control RPS costs. Some RPS laws grant the PUC the authority to delay or freeze RPS requirements, or grant waivers to individual utilities, if costs would be deemed excessive (e.g., under a *force majeure* clause). Regulators also often have the ability to review and approve PPAs and/or cost recovery for RPS resources, and thereby limit the costs incurred.

Importantly, cost containment mechanisms may sometimes serve as only a "soft" cap, depending upon the specifics of their design. In states with ACPs, for example, utilities might conceivably pay a higher price for RECs than the ACP level if ACPs are not recoverable or when RECs are purchased through long-term bundled PPAs. Similarly, rate impact or revenue requirement caps may be voluntary; in Washington, for example, a utility may opt to abide by the cap but is not obliged to do so. More generally, cost containment under many of the above mechanisms may be imperfect to the extent that certain costs or benefits are not fully counted. For a broader discussion of the design and limitation of RPS cost containment mechanisms, see Stockmayer et al. (2012).

Table 9. Cost Containment Mechanisms

State	Cost Containment Mechanism(s)	Details of Cost Containment Mechanism(s) Applicable to Final Target Year
AZ	No specific cap	
CA	No specific cap (under development)	
CO	Rate impact/revenue requirement cap	2% (IOUs and coops) or 1% (municipal utilities) of each customer's annual electricity bill
CT	ACP	$55 (Class I and Class II)
DC	ACP	$50 (Tier I and Solar), $10 (Tier II)
DE	Rate impact/revenue requirement cap	For IOUs, 3% (total RPS) and 1% (Solar) of total retail electricity costs; for municipal utilities, 4% (total RPS); rulemaking currently underway
	ACP	$80 (Non-Solar), $500 (Solar)
HI	No specific cap	
IA	No specific cap	
IL	Rate impact/revenue requirement cap	2.015% of average 2007 retail rates
	ACP	Applicable only to alternative retail electricity suppliers, which are required to meet at least 50% of RPS obligation with ACPs; equal to average REC price paid by IPA
KS	Rate impact/revenue requirement cap	1% of retail revenue requirement (gross RPS costs)
MA	ACP	$73.7 (Class I Non-Solar), $30.3 (Class II-Existing RE), $12.1 (Class II-Waste Energy), $384, (Class I Solar-SREC I program), $316 (Class I Solar-SREC II program)
MD	ACP	$40 (Tier I Non-Solar), $15 (Tier II), $50 (Tier I Solar)
	Rate impact/revenue requirement cap	10% (Tier I Non-Solar), 1% (Tier I Solar) of retail sales revenue
ME	ACP	$70.9 (New renewables tier)
MI	Surcharge cap	$3.00/month (residential), $16.58/month (small commercial), $187.50/month (large commercial and industrial)
MN	No specific cap	
MO	Rate impact/revenue requirement cap	1% of retail revenue requirements*
MT	Renewable energy contract price cap	Capped at avoided costs for most utilities
NC	Surcharge cap	$34/year (residential), $150/year (commercial), $1,000/year (industrial)
NH	ACP	$62.1 (Class I-New RE), $28.2 (Class I-Thermal), $62.1 (Class II-Solar), $40.1 (Class III-Existing Biomass), $33.8 (Class IV-Existing Small Hydro)
NJ	ACP	$50 (Tier I and Tier II), $239 (Solar)
NM	Rate impact/revenue requirement cap	3% of total revenue
	Per-customer cost cap	For customers using >10 million kWh/year, $99,000/year (2012 dollars) or 2% of their bills, whichever is less
NV	No specific cap	
NY	Renewable energy fund cap	PSC Order establishing program budget through final target year
OH	Rate impact/revenue requirement cap	3% of generation costs
	ACP	$61.0 (Non-Solar), $50 (Solar)
OR	Rate impact/revenue requirement cap	4% of annual retail revenue requirements
	ACP	Established bi-annually by Oregon PUC ($110 for 2014 and 2015)
PA	ACP	$45 (Tier I Non-Solar and Tier II), 2x market value of RECs (Tier I Solar)
RI	ACP	$73.9
TX	Financial penalty	$50/MWh, could be passed through by competitive suppliers
WA	Rate impact/revenue requirement cap	4% of annual retail revenue requirements
WI	No specific cap	

Note: All ACP rates identified are in units of $/MWh and represent the scheduled ACP rate for the final RPS target year. Several states (MA, ME, NH, OH, RI) adjust ACP rates for some or all tiers annually based on inflation; in these cases, we estimate the ACP rates for the final RPS target year using the CPI projection from the EIA Annual Energy Outlook 2014 Early Release. For MA, where the Class I-New RE tier has no final target year, we estimate the non-solar ACPs for 2020, and show the scheduled solar ACP rates for that year as well.

Note: In states without specific caps, cost containment may still occur through regulatory oversight (e.g., authority of the PUC to delay or freeze RPS requirements if costs are deemed burdensome, review and approval of contracts and cost recovery, etc.).

*Interpretation and implementation of the MO cost cap is currently subject to substantial debate.

In Figure 11, we have translated, where possible, the cost containment mechanisms outlined in Table 9 into the equivalent maximum percentage increase in average retail rates, for the year in which each state's RPS target reaches its peak.[38] In effect, these values represent the maximum potential annual RPS cost, subject to the various caveats discussed above, for the single year in which each state reaches its final target. For comparison, Figure 11 also presents estimated statewide-average RPS costs for the most recent historical year available (i.e., the same data presented in Figure 10). Excluded from Figure 11 are those states currently without any mechanism to cap total incremental RPS costs, though some of those states may have other kinds of mechanisms or regulatory processes to limit RPS costs.

States relying upon ACPs as their primary cost containment mechanism are grouped on the left-hand side of the figure. Among those states, RPS costs are generally capped at the equivalent of 6-9% of average retail rates.[39] The effective caps are somewhat higher in Massachusetts (16%) and New Jersey (13%) due to relatively high solar set-aside targets and/or ACP levels.[40] As shown, estimated recent RPS compliance costs in this set of states are generally well below the corresponding caps. To a significant extent, this is simply because current RPS targets are well below the final-year targets, and cost caps are arithmetically related to the final-year targets. Rising RPS targets will put upward pressure on REC prices, which in many of the Northeastern states are already near their respective ACPs. At the same time, ACP rates will generally remain fixed (in either real or nominal terms) or, in the case of many states' solar ACPs, will decline over time. Of particular note, solar ACPs in Washington D.C., Maryland, and Ohio are scheduled to decline to \$50/MWh, from current levels of \$350-500/MWh. This combination of possible upward pressure on REC prices and fixed or declining ACPs could constrain achievement of RPS targets and push total compliance costs towards the maximum levels shown in Figure 11. That outcome is not foregone of course, if continued reductions in renewable energy costs and/or increases in wholesale power prices restrain growth in REC prices.

States with some form of cost containment other than, or more binding than, an ACP are grouped on the right-hand side of Figure 11. In general, cost caps among these states are relatively restrictive, typically ranging from the equivalent of 1-4% of average retail rates. Not surprisingly, cost caps have already become binding in several of these states. In particular, utilities in New Mexico have, on a number of occasions, requested and been granted reductions in their RPS obligations in order to remain within the overall rate impact cap (termed the "Reasonable Cost Threshold") and/or to remain within the per-customer cost cap for large customers. Also, utilities in Missouri (not included in Figure 11) have sought waivers from solar rebate requirements included in the RPS law, in order to remain within the state's cost cap.

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[38] Figure 11 excludes three states–Pennsylvania, Kansas, and Missouri–with numeric cost caps that cannot be expressed on a sufficiently comparable basis to the other states. Pennsylvania is excluded, because the ACP rate for its solar set-aside is not pre-defined. Kansas's cost cap applies to gross costs, rather than incremental costs. Missouri's cost cap is currently subject to substantial debate, and a binding ruling on its interpretation has not yet been issued.

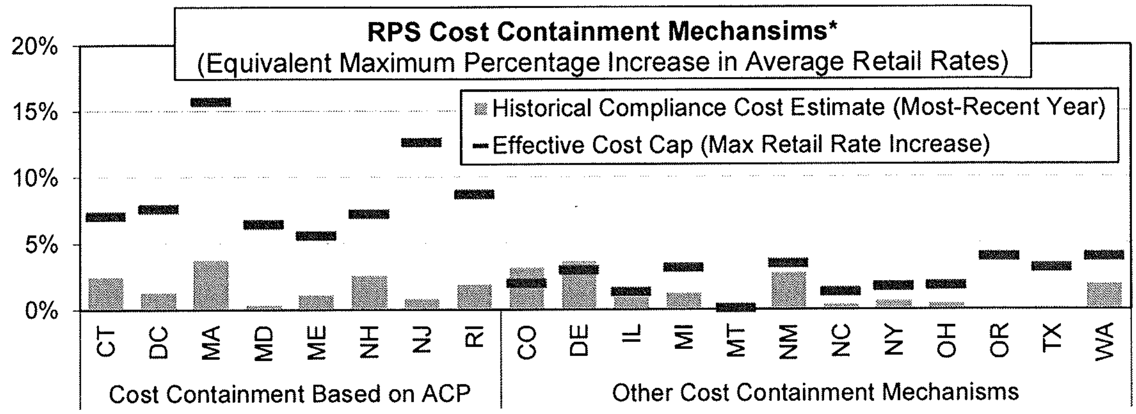
[39] Although not included in the figure, Pennsylvania's main tier and secondary tier ACPs equate to effective cost cap of 7.4% of average retail rates for the final target year. In comparison, RPS costs for the most recent historical year (2012) equated to 0.2% of retail rates.

[40] Massachusetts's RPS does not have a single terminal year. For the purpose of constructing Figure 11, the cost cap was calculated based on RPS targets in 2020. This is the year when the state's cost cap reaches a local maximum, declining in the years immediately following as the solar ACP rates decline and the SREC-I program expires.

Several other states appear to have surpassed their caps, but for various reasons those caps have not yet been binding. In Colorado, Xcel Energy has a 2% cap on its RPS surcharge. The utility–which, not incidentally, has far-surpassed its RPS procurement targets–has been allowed to incur costs in excess of the surcharge amount and defer the balance forward for collection from ratepayers in later years (Stockmayer et al. 2012). In Delaware, Delmarva Power & Light's RPS procurement costs for 2012 appear to have exceeded the 3% cost cap; however, the administrative rules for implementation of the cap are still under development (as of this writing), and it is therefore not yet practically enforceable. Finally, Kansas had statewide average renewable energy costs in 2012 equivalent to 1.7% of average retail rates, which is greater than the 1% rate impact cap for the RPS (KCC 2013). However, the 2012 costs are based on all renewables procured by the state's utilities, beyond just those resources attributed to the RPS (Solorio 2014).

Other states are approaching or could begin to approach their respective caps. For example, Illinois, North Carolina and Ohio all have relatively low cost caps (1-2% of average retail sales) and targets that rise considerably over the coming decade. In Oregon as well, cost caps may become an issue for some utilities, even though historical compliance costs have been quite low. Portland General Electric, in particular, has forecasted sizeable increases in its RPS rate impacts over the next five years that reach or exceed the 4% rate cap under a number of scenarios. New York is also likely to hit its cap, though this is by design, as the cap is based on a schedule of revenue collections adopted by the PSC and deemed necessary for achievement of the target. In Montana, the cost cap effectively prohibits any net cost from RPS resources. Thus far, the cap has not been binding–no doubt the result of the high quality wind resource sites in the state–but the sheer restrictiveness of the cap suggests that it could at some point become limiting.

Of the states on the right-hand side of Figure 11, Texas and Michigan are both seemingly at low risk of reaching their cost caps, even though the caps are on par with other states within the group. In the case of Texas, scheduled increases in the RPS target are relatively small, and installed renewable capacity in the state already well-exceeds the final-year (2015) target. Given the low REC prices that have prevailed to-date, RPS compliance costs in Texas would thus seem unlikely to approach the state's cost cap. In Michigan, the cost cap is specified in terms of a maximum customer surcharge, and the state's two large IOUs reduced their surcharges substantially in 2014. In their latest RPS procurement plans, both utilities project attainment of their RPS targets going forward, without any significant increase in surcharges (DTE 2013b; Consumers 2013b).



** For states with multiple cost containment mechanisms, the cap shown here is based on the most-binding mechanism. MA does not have a single terminal year for its RPS; the calculated cost cap shown is based on RPS targets and ACP rates for 2020. "Other cost containment mechanisms" include: rate impact/revenue requirement caps (DE, KS, IL, NM, OH, OR, WA), surcharge caps (CO, MI, NC), renewable energy contract price cap (MT), renewable energy fund cap (NY), and financial penalty (TX). Excluded from the chart are those states currently without any mechanism to cap total incremental RPS costs (AZ, CA, IA, HI, KS, MN, MO, NV, PA, WI), though some of those states may have other kinds of mechanisms or regulatory processes to limit RPS costs.*

Figure 11. RPS cost caps compared to estimated recent historical costs

4 Benefits of RPS

The estimated RPS incremental costs reported earlier are net costs that account for a narrow set of benefits–namely the benefits that accrue to the utility, in the form of reduced costs for conventional generation. However, policymakers often consider RPS costs within the broader context of the possible benefits of those policies to society at large. Potential societal benefits of RPS policies include air emissions reductions, health benefits, fuel diversity, electricity price stability, energy security, and economic development (EPA 2011; Cory and Swezey 2007). Often RPS legislation includes language indicating that the policy is designed to achieve particular goals, such as these.

This section summarizes RPS benefits estimates, based on published studies for individual states, and discusses key methodological considerations. As such, the estimated benefits itemized in this document do not result from the application of a standardized approach or the use of a consistent set of underlying assumptions. Because the reported values may differ from those derived through a more consistent analytical treatment, we do not provide an aggregate national estimate of RPS benefits, nor do we attempt to quantify net RPS benefits at national or state levels. Benefits estimates, for example, of the social value of carbon emissions reduction and the human health impacts of reduced air emissions, are based on a variety of methodologies and assumptions. In comparison to the summary of estimated RPS costs, the summary of RPS benefits is more limited, as relatively few states have undertaken detailed benefits estimates. Further, for those states that have estimated RPS benefits, most assess only a limited number of impact types; as a consequence, some types of benefits are not reflected in this report.

Estimating the broader impacts of RPS policies (and other types of policies in general) [41] can be challenging. The level of rigor in assessment can vary substantially and a variety of methods can be employed (Leon 2012), depending on available resources to conduct modeling or detailed assessments. When preparing RPS evaluations, many states have qualitatively discussed benefits while a smaller number have attempted to develop quantitative estimates.

Comparison of estimated costs to benefits is also challenging, even when they are reported in the same study, given that some incremental cost calculations may already take into account certain benefits, analysis time periods may differ, benefits assessments may address only particular types of benefits, and other factors. In addition, certain benefits (e.g., avoided emissions) may accrue for the lifetime of the renewable plant, while costs are incurred over a shorter period. One study conducted by NYSERDA does offer a direct comparison of RPS benefits and costs finding that the New York RPS yielded a net present value benefit of $1.6 to $3.5 billion, with the range depending primarily on assumptions of the value of CO_2 savings (NYSERDA 2013b). Massachusetts also compared estimated compliance costs to the benefits, primarily price suppression effects, showing 2012 costs of $111 million compared to benefits of $328 million in the same year (EOHED and EOEEA 2011). Most other states for which we have identified benefits estimates did not conduct direct comparisons.

[41] In this analysis, we focus on the impacts of RPS policies in particular, but do not examine the impacts of other renewable energy policies. While RPS policies can have positive impacts, there are other types of policies that could have equivalent impacts, potentially at lower cost.

Table 10 summarizes studies identified in our literature review that quantitatively assess benefits of state RPS policies in current or future years. Based on our review of studies, states have most commonly attempted to quantitatively assess avoided emissions and human health benefits, economic development impacts, and wholesale electricity price reductions. The studies identified include those required by statute, filed as part of an IRP docket, and prepared for regulatory commissions, energy boards, or public benefit corporations. Most of these studies are prospective in nature, assessing not only the current RPS impacts, but also examining future impacts, in contrast to the cost estimates previously discussed that are retrospective. Results from third-party studies referenced in the aforementioned documents are also included here. While we attempted to conduct a thorough literature review, we have likely omitted some analyses. However, this review provides an indication of the types of benefits analyses that have been conducted and the range of benefits found. In this analysis, we did not review the broader literature on renewable energy benefits in general, but are focused only on analyses conducted as part of state-level RPS evaluations.

Table 10. Summary of State Studies of RPS Benefits and Benefits Assessed

State	Emissions and Health	Economic Development Impacts	Wholesale Market Impacts	Study required?	Source
CT	✔			As part of IRP	The Brattle Group et al. 2010
		✔			CEEEP and R/ECON 2011
DE	✔			As part of IRP	DPL 2012b
IL	✔	✔	✔	✔	IPA 2013
ME	✔	✔	✔	✔	LEI 2012
MA			✔	✔	EOHED and EOEEA 2011
MI		✔	✔	✔	MPSC 2013
NY	✔	✔	✔	✔	NYSERDA 2013b; 2013c
OH	✔			✔	PUCO 2013a
			✔	✔	PUCO 2013c
OR		✔		✔	ODOE 2011

Note: The results found in a single report may have been classified under more than one category.

The following sections review estimated benefits and impacts of state-level RPS policies, with respect to 1) emissions and human health; 2) economic development; and 3) wholesale market price impacts. We summarize the estimated benefits and methods used in studies identified in the literature review, which were often prepared for state legislatures or commissions. While methods for developing benefits estimates differ substantially from methods used to assess policy costs, this information can provide context for considering the cost of RPS policies presented earlier.

4.1 Emissions and Human Health

One of the most often quantified environmental benefits of renewable energy is the avoided air pollutant emissions and associated human health benefits. Typically, estimates of avoided emissions focus on carbon dioxide (CO_2), sulfur oxides (SO_X), and nitrogen oxides (NO_X). In some cases, the human health benefits of these reduced emissions are estimated as well by applying monetary values to, for example, the reduced morbidity or mortality from air quality improvements. In other instances, monetary impacts are estimated based on the avoided cost of compliance with environmental regulations.

There are two common approaches to estimating RPS emissions impacts. The most robust approach is to conduct detailed modeling of the electric system with and without the renewable generation to determine the mix of plants that would be operating and the overall system emissions in each scenario. This approach yields the most robust results because it accounts for the operation of the facilities at each hour of the day—renewable facilities may be displacing different types of conventional generators throughout the course of a day. A simplified approach is to estimate the marginal generating unit that would typically not be operating as a result of the renewable generator and apply the unit's emission rate to the displaced generation. This approach is simplified and yields approximate results. Table 11 summarizes estimates of the emissions and associated monetary benefits from RPS policies for several states where data are available.

Table 11. Summary of Estimates of Emissions and Human Health Benefits of State RPS

State	Estimated Benefit	Benefits $/MWh of RE	Avoided CO_2/MWh	Period	Description	Source
CT	Not estimated	N/A	0.39-0.53 tons/MWh	2020	Avoided CO_2 emissions of 0.39-0.53 tons/MWh of renewable generation	Brattle Group et al. 2010
OH	Not estimated	N/A	N/A	2014	CO_2 emissions reduced from 116.36 million metric tons in reference case to 116.16 (-0.17%), and to 115.79 (-0.5%) in scenarios	PUCO 2013c
ME	$13 million	$7/MWh	0.57 tons/MWh	Annual	Avoided allowance costs for 96 tons for SO_2, 1,629 tons for NO_X and 1.1 million tons for CO_2. CO_2 valued at $12/ton	LEI 2012
DE	$980 - $2,200 million*	N/A	N/A	2013 – 2022	Human health benefits due to improvements in air quality from emission reductions in power generation and other sectors	DPL 2012b
IL	$75 million	$11/MWh**	0.79 tons/MWh**	2011	Avoided allowance costs for 5,481,327 tons of CO_2 and 4,765 tons of NO_X. CO_2 valued at $5/ton	IPA 2013
NY	Not estimated	N/A	N/A	2002-2006	4,028 tons of NO_X, 8,853 tons of SO_2, and 4.1 million tons of CO_2	NYSERDA 2013a
	$312 - $2,196 million***	$3–22/MWh	0.05 tons/MWh	2002 – 2037	Value of avoiding 50.29 million tons of CO_2. CO_2 valued at $15 /ton and $85/ton.**	NYSERDA 2013b
	$48 million	$0.5/MWh	N/A	2002 – 2037	Value of avoiding 278 pounds of mercury, 15,214 tons of NO_X and 14,987 tons of SO_2	NYSERDA 2013b

*Delaware estimates reported in $2010 dollars.

**Estimated based on 6.9 million MWh of renewable energy needed to meet the 2011 RPS requirements (IPA 2010, Zuraski 2014).
*** The estimated monetary impact is a net present value calculation reported in $2012, thus the avoided tons of CO_2 multiplied by values of $15/ton and $85/ton differs from the reported $312 - $2,196 million.

4.1.1 Emissions Rate Approach

In our literature review, we identified only one state—Maine—that used a simplified emission rate method to estimate the avoided emissions.

Maine. Maine's PUC (MPUC) retained London Economics International (LEI) to analyze the costs and benefits of RPS compliance, as required by the state legislature.[42] To estimate emissions benefits, LEI used half of the aggregate nameplate capacity of wind generation projects proposed in the ISO New England interconnection queue located in Maine, or 625 MW, to calculate impacts (LEI 2012). LEI calculated avoided emissions by assuming that natural gas-fired generation was displaced by the renewable energy generated under Maine's RPS. Using U.S. EPA average emission rates for natural gas-fired generation, LEI calculated an annual reduction of 96 tons for SO_2, 1,629 tons for NO_X, and 1.1 million tons for CO_2. The annual monetary value of avoided emissions was calculated at $13 million based on allowance prices of $0.80/ton for SO_2 (based on the current forwards), $20/ton for NO_X (based on the current forwards), and $12/ton for CO_2 (LEI 2012).

4.1.2 Modeling Avoided Emissions Approach

Several states have conducted more detailed electric system modeling to understand avoided emissions. The following are examples of this approach.

Connecticut. As part of their IRP for Connecticut, a private consultant and two electric distribution companies used the Day-Ahead Locational Market Clearing Prices Analyzer (DAYZER) model to simulate resource dispatch and measure economic impacts and emission levels for the ISO New England region. The study compared the RPS requirements as of 2010 with lower levels of ISO-wide renewable energy deployment under five scenarios and also varied assumptions regarding natural gas prices, carbon prices, and load growth. Using this methodology, the study found avoided CO_2 emissions of between 0.39 tons/MWh and 0.53tons/MWh of renewable generation (The Brattle Group et al. 2010).

Delaware. The electric distribution company Delmarva Power and Light (DPL) used a group of modeling tools to calculate the expected emissions from power plants in the PJM Delmarva zone between 2012 and 2022 as part of its 2012 IRP for Delaware. The study assessed the impact of not only the RPS, but also demand side management programs, energy efficiency programs, and emission controls for coal plants. DPL's results show a reduction in CO_2, SO_2, and NO_X emissions from power plants of approximately 30%, 66%, and 56%, respectively, from 2012 levels, in 2022 (DPL 2012b). Human health benefits over the 2013-2022 period for Delaware due to the improvements in air quality, including reductions from the transportation and other sectors, were estimated to be between $980 million and $2.2 billion for Delaware, and between $13 and $29 billion for the mid-Atlantic Region. Monetized benefits of improvements in air

[42]MPUC was tasked with examining direct investment, induced effects, job creation, and other benefits resulting from a diversified electricity generation fleet.

quality were based on estimates of reduced health effects specifically related to ozone and particulate matter-related morbidity and mortality (e.g., from chronic bronchitis, emergency room visits for asthma). DPL estimated that the health-related costs associated with power plant emissions in Delaware during the same period ranges between \$2.5 and \$6.8 billion (DPL 2012b).

Illinois. The Illinois Power Agency (IPA), an independent agency established by the legislature to procure power for the state's two largest electric utilities to comply with the RPS, prepares an annual report as required by statute that includes RPS compliance status and an analysis of costs and benefits. To assess RPS benefits, IPA hired a private consultant to model the electricity market. The study examines both PJM and MISO markets, both of which operate in Illinois, with and without renewable generation to calculate emission reductions and effects on locational marginal prices (LMP) for calendar year 2011 (an historical rather than prospective analysis). The study used the MarSi model, a software tool developed by GEMS for electricity market simulations. The reduction in emissions directly attributable to renewable energy generation amounted to 5,481,327 tons of CO_2 and 4,765 tons of NO_X. Using trading values for emission allowances of \$10,000/ton of NO_X and \$5/ton of CO_2, IPA calculated a total emission cost reduction of approximately \$75 million due to renewable energy generation (IPA 2013).

New York. NYSERDA has examined historical and future emissions reductions as part of its annual RPS performance reports and also within periodic RPS evaluations. In its 2012 historical performance report (covering the 2006-2012 period), NYSERDA found emissions reductions attributable to renewable energy generation of approximately 4,028 tons of NO_X, 8,853 tons of SO_2, and 4.1 million tons of CO_2 (NYSERDA 2013a).

In 2013, NYSERDA completed an historical and forward-looking assessment of the New York RPS Main Tier, as required by the Public Service Commission, focusing on compliance status, direct economic impacts, cost-benefits analyses, and resource availability and costs.[43] The study estimated avoided carbon emissions and other electric system impacts using ICF International's Integrated Planning Model (IPM). The study considered main tier renewable energy projects with signed contracts as of December 31, 2012, referred to as the Current Portfolio. The avoided emissions calculated for the Current Portfolio over the course of the 2002-2037 study period[44] were 50.29 million tons of CO_2, 278 pounds of mercury, 15,214 tons of NO_X, and 14,987 tons of SO_2 (NYSERDA 2013b). Using \$15/ton and \$85/ton as boundaries for the value of avoiding CO_2 emissions, NYSERDA estimated a present value between \$312 million and \$2,196 million. For monetization of health benefits from criteria pollutants, NO_X and SO_2 were valued at \$3,500/ton and \$1,100/ton, respectively. A value of \$194.5 million/ton was used for mercury. Avoided emissions of NO_X, SO_2, and mercury were estimated to produce \$48 million in health benefits (NYSERDA 2013b).

Ohio. The Public Utilities Commission of Ohio (PUCO) used PROMOD IV, a nodal electricity market simulation tool, to quantify changes in generator emissions that occur as a result of

[43] The Main Tier of NY's RPS includes larger power generation plants in the utility side of the meter and accounts for approximately 92% of the total RPS requirement.
[44] This period spans over the life of the systems in the current portfolio.

Ohio's Alternative Energy Portfolio Standard (AEPS). The study examined two scenarios over calendar year 2014. The first scenario considered projects that were operational at the time of the study; the second considered projects that had been approved by the Ohio Power Siting Board, but were not operational. The results for each of these scenarios were compared to a scenario where "no utility-scale renewable resources are developed within Ohio." CO_2 emissions were reduced relative to this no utility-scale renewable resources scenario from 116.36 million metric tons to 116.16 for the first scenario, a change of -0.17% in, and to 115.79 million metric tons, in the second scenario, a change of -0.5% (PUCO 2013c).

Overall, estimates of air quality benefits range from on the order of tens to hundreds of million dollars annually or about $4-$22/MWh of renewable generation, with some studies presenting a wide range of estimates depending on assumptions. Often, the value of CO_2 emissions benefits (Table 11) drives the estimates, because of the magnitude of those reductions, compared to reductions of other air pollutants. In order to calculate the estimated monetary impact of avoided CO_2 emissions, the tons of avoided CO_2 emissions can be multiplied by the value of the CO_2. Thus, assumptions regarding the value of CO_2 influence results considerably. An interagency assessment of the social cost of carbon found a range from $11 to $89/metric ton of CO_2 for the year 2010 (in $2007 dollars) depending on the discount rate used (Interagency Working Group on Social Cost of Carbon 2013). The NYSERDA study used a similar range ($15/ton and $85/ton) for valuing avoided CO_2 emissions, while most of the other studies examined used a single estimate of the value of CO_2 typically consistent with the lower end of the range (or below) estimates reported by the interagency working group. Maine's assessment valued CO_2 at $12/ton (LEI 2012) and the IPA assessment valued CO_2 at $5/ton (IPA 2013).

There are a number of considerations with respect to methods of assessing air emissions impacts that can influence their ability to be compared to incremental costs. In cases where cap and trade policies are in place, renewable energy may not provide emissions reductions from capped pollutants, unless there is a set-aside for renewable energy. At the same time, even in this instance the increased production of emissions-free renewable electricity will reduce the cost of complying with the cap-and-trade program, as proxied by the marginal allowance price. If allowance prices are used to estimate benefits, however, it is important to ensure that they are not already captured in the estimated incremental cost of the renewable energy. Allowance prices should already be embedded in wholesale electricity prices, for example, so if wholesale prices are used in cost calculations, then those estimates should already take into account these impacts. Similarly, if a proxy plant used to calculate the incremental cost of the RPS includes allowance prices or carbon costs, then these emissions impacts are captured in the incremental cost assessment. Another factor that complicates comparison is that often benefits estimates are forward looking, while the incremental costs are based on historical compliance. For these reasons, it is difficult to compare these estimates to the incremental costs discussed earlier; however, treatment of these issues varies from state to state.

4.2 Economic Development Impacts

Economic development impacts are also of significant interest in evaluating RPS policies. Often policymakers seek to achieve economic development goals with RPS policies; therefore, these impacts are generally of interest, and in some cases, their quantification is required by the state legislature.

Economic impacts of renewable energy development resulting from an RPS include impacts on the number of jobs, direct investment from construction and operation of facilities, tax revenues, as well as indirect and induced economic impacts, which result from the purchase of goods and services.[45] An RPS can also affect electricity prices, which can impact economic activity. One key issue is whether the assessment examines gross impacts (e.g., new jobs supported) versus net impacts that consider shifts in employment. Understanding net impacts associated with the development of new renewable energy projects requires more detailed analysis of changes in the operation of other generating units, fuel usage, utility revenues, electricity prices, and residential and commercial energy expenditures (Steinberg et al. 2011). Many states focus on the boundary of impacts within the state, but in reality, shifts in jobs may occur within the region. Furthermore, some assessments focus on only one particular aspect of the economic impacts.

A variety of methods can be employed to conduct economic assessments; these involve varying degrees of rigor. Simplified methods, which yield estimates of gross impacts, include input-output models or case study approaches often focused on specific renewable energy facilities. Input-output models, the most common method used in gross impact analysis, calculate the direct, indirect, and induced economic impacts by quantifying relationships between sectors in an economy at a point in time, but cannot analyze changes in electricity prices (e.g., IMPLAN, RIMS II). More sophisticated economic modeling tools can also be used to assess net impacts, including: 1) econometric models that assess impacts on the economy; and 2) computable general equilibrium models (CGE models) that examine the flow of goods and services through the economy (see U.S. EPA 2011 for more detail on methods and models available). Table 12 summarizes estimates of the economic impacts of RPS policies for several states.

[45] See the RIMS II user's guide for more in-depth discussion of these components, Bureau of Economic Analysis, Department of Commerce, https://www.bea.gov/regional/pdf/rims/RIMSII_User_Guide.pdf, accessed January 30, 2014.

Table 12. Summary of Estimates of RPS Economic Impacts

State	Estimated Benefit/Impact	Benefits $/MWh of RE	Period	Description	Source
CT	Negative to positive GSP impact	N/A	Through 2020	Modeling showed retail electricity prices increased 0.86% to 3.48%, which reduced gross state product (GSP) 0.01% to 0.03%. One scenario showed an increase in GSP of 0.02%	CEEEP and R/ECON 2011
IL	$3003 million*	$14/MWh*	Construction	Construction impact of the 23 largest wind farms installed by 2012	IPA 2013; Loomis 2013
	$140	$16/MWh	Annual, during project lifespan	Annual operational impacts from onsite labor, local revenue and induced impacts	IPA 2013; Loomis 2013
ME	$1,140 million	$24/MWh	Construction	2% increase in GSP	LEI 2012
	$7.3 million	$4/MWh	Annual, during project lifespan	$6.3 million annually in tax revenue for local governments and $1 million of revenue/year for private landowners during the operating life of the projects	LEI 2012
MI	$159.8 million	N/A	Construction	Economic impacts of four wind farms built in Michigan	MPSC 2013
NY	$1,252** million	$13/MWh	Project lifespan	Present value of the total direct investments in NY during the life of the projects	NYSERDA 2013b
	$921 million	$9/MWh	Project lifespan	Cumulative impact on GSP	NYSERDA 2013b
OR	Not estimated	N/A	Project lifespan	Estimated jobs resulting from renewable energy projects, based on survey	ODOE 2011

*Illinois benefits estimates converted from $2008 to $2012. Calculations per MWh are estimated assuming a 30% capacity factor and for the construction benefits, spread over generation for a 25-year project life.
**New York estimates are in net present value and $2012.

4.2.1 Input-output Models and Simplified Approaches

The following states conducted assessments using input-output models, case studies, or anecdotal information on the impacts of particular renewable energy facilities to assess economic impacts. These typically assess gross impacts.

Illinois. In 2012, Illinois State University used the Jobs and Economic Development Impact (JEDI) model,[46] an input-output model for estimating gross economic impacts, to estimate the state-level economic impacts of the 23 largest wind farms installed in Illinois at the time of the analysis (Loomis et al. 2013). The results showed that 3,335 MW[47] of nameplate wind capacity could support a total economic impact of $5.98 billion over the estimated 25-year life of the

[46] The JEDI model was developed by NREL and is publically available at: http://www.nrel.gov/analysis/jedi/.
[47] For comparison, Illinois had 3,568 MW of cumulative wind capacity by the end of 2012.

projects (IPA 2013). The study also estimated that the projects would support 19,047 full-time equivalent jobs during construction periods with a total payroll of more than $1.1 billion, 814 permanent jobs with an annual payroll of nearly $48 million, $28.5 million in annual property taxes, and $13 million annually in extra income for Illinois landowners who lease their land to wind farm developers (Loomis et al. 2013).

Maine. In addition to assessing emissions benefits, the LEI report for the Maine PUC (see Emissions and Human Health section) quantified the economic impacts of RPS compliance using Maine-specific multipliers from the Regional Input-Output Modeling System (RIMS II), which was developed by the U.S. Bureau of Economic Analysis. LEI used half of the aggregate capacity of the wind projects proposed to be built in Maine, or 625 MW, as an input for the RIMS II model. Assuming an average cost of $2,563/kW for wind generation capital costs and assuming 35% of the total investment, or roughly $560 million, stays in Maine, LEI estimated that the investment supported $1,140 million (2%) in GSP and roughly 11,700 jobs during construction, plus $6.3 million annually in tax revenue for local governments and $1 million of revenue/year for private landowners during the operating life of the projects (LEI 2012). LEI also calculated the potential increase in electricity prices resulting from a higher RPS requirement and REC price and its effect on jobs and Maine's GSP. LEI used RIMS II multipliers to calculate that a 10% RPS requirement with a REC price of $33/MWh[48] would lead to a reduction in GSP of 0.06% and the loss of 129 jobs statewide (LEI 2012).

Michigan. The Michigan Public Service Commission (MPSC) is required by state statute to submit to the legislature an annual report on the implementation of the state's RPS and its cost-effectiveness, including the impact on employment. In its 2013 report, the MPSC included information on the economic impacts of wind farms owned by two utilities, although no information was provided on the methods used to determine these impacts (MPSC 2013). Consumers Energy reported that the construction of the 100-MW Lake Winds Energy Park wind farm resulted in more than $4 million in direct payments to Michigan vendors, $4.8 million in indirect economic impact, plus more than $1 million in induced impacts. DTE Energy estimated its three wind parks, one constructed per year through 2013, contribute $150 million in total economic benefits to Michigan.

Oregon. Oregon Department of Energy (ODOE), which is required by law to evaluate the impact of the state's RPS on employment, surveyed Oregon RPS-eligible facilities to assess economic impacts in 2011. Nine of twelve non-solar facilities surveyed reported 82 full-time equivalents employed at the time of the study. Reported salaries ranged between $30,000 and $70,000 for administration jobs, $50,000 to $125,000 for managerial jobs, and $30,000 and $65,000 for O&M jobs (ODOE 2011). In addition, prospective wind facilities of 35 MW or greater anticipated the creation of 6 to 40 permanent operation jobs and between 120 and 475 temporary construction jobs per wind farm. Portland General Electric also provided information about its 450-MW Biglow Canyon wind farm, which employed about 200,000 person hours (about 95 FTEs) during each of the three phases of construction (ODOE 2011).

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[48] The RPS requirement was 3% and REC price was $24/MWh at the time of the study.

4.2.2 Economic Modeling Approach

In our review, we identified assessments conducted for the following states using more detailed modeling approaching, including use of econometric models. While these assessments utilized more detailed modeling approaches, in some instances they focused on only one aspect of the economic impacts of the RPS.

Connecticut. In 2011 the Center for Energy, Economic, and Environmental Policy (CEEEP) at Rutgers and the Rutgers Economic Advisory Service (R/ECON) employed the R/ECON econometric model, which examines net effects, to show the "direction and magnitude" of the effects that the RPS requirement could have on Connecticut's economy. The team modeled a comparison scenario to serve as a baseline, in which current RPS requirements continue unchanged until 2020 and REC prices are set to $0. Five additional scenarios consider different REC prices and the job impacts associated with energy efficiency programs and a solar carve-out. In the six scenarios, the study assumed no additional direct jobs would be supported in Connecticut as a result of the RPS outside the solar carve-out considered in one scenario. In four of the five scenarios, retail electricity prices increased between 0.86% and 3.48%, which in turn reduced the GSP between 0.01% and 0.03%. In contrast, the Flat RPS scenario, which is the same as the Comparison scenario (except the RPS is kept flat after 2010), saw an increase in GSP of 0.02%. Price increases also put downward pressure on non-agricultural jobs, creating a loss of 880 to 2,790 jobs across the state. The two scenarios with absolute jobs higher than the Comparison scenario were the Flat RPS (560 jobs) and the Solar Carve-out (130 jobs) scenarios (CEEEP and R/ECON 2011).

New York. In New York, energy suppliers contracted through RPS solicitations are required to report direct economic benefits every three years to demonstrate compliance with the requirement that at least 85% of said benefits accrue to the state. NYSERDA calculated that in-state economic benefits average $27/MWh, in 2012 dollars, for Main Tier projects with contracts as of December 31, 2012, based on data reported by energy suppliers. NYSERDA estimated the present value of the total direct investments in New York during the life of the projects at $1,252 million, compared to an estimated ratepayer cost of $431 million[49] (NYSERDA 2013b).

Using REMI's PI+ model,[50] NYSERDA estimated a net increase of 668 direct, indirect, and induced jobs per year during the study period (2002-2037), equivalent to approximately 24,000 job-years, including jobs added, saved, and lost. The cumulative impact on GSP is approximately $921 million (net present value, 2012 dollars). This number includes direct impacts from the construction and O&M of renewable energy plants, a net increase on the percentage of energy produced in-state, wholesale energy price reductions, and net capital and operation costs reductions (NYSERDA 2013b).

Overall, states have estimated economic impacts on the order of hundreds of millions of dollars for the construction period (one-time), and in some cases tens of millions of dollars in annual economic benefits over the project lifetime. These estimates translate to about $22-$30/MWh of renewable generation. One study found that the RPS led to electricity price increases that

[49] Present values calculated in 2012 dollars with a 5.5% discount rate.
[50] The REMI model is a combination of input-output, computational general equilibrium, and econometric models.

reduced gross state product by less than 1%. The methods and assumptions used to conduct assessments vary considerably across states with several states using screening or simplified approaches, while others have used more detailed modeling. For those studies that estimate gross impacts (e.g., jobs supported), an obvious limitation is the lack of consideration of net job impacts and therefore an inability to capture the true economy-wide impact of increased use of renewable energy. Often, the studies evaluated are limited by focusing on only one particular aspect of the economic impacts.

4.3 Wholesale Market Price Impacts

Finally, in some cases, studies have attempted to assess reductions in wholesale market prices resulting from additional renewable generation (see Table 13). Renewable generation can depress wholesale market prices by eliminating more expensive generating sources from the dispatch stack, which reduces the market clearing price that is paid to all generators. Dispatch modeling can be used to estimate these impacts by running scenarios with and without the renewable generation on the system. Wholesale price suppression benefits differ from the benefits previously covered in that they pertain to electricity rates and wholesale prices, which could be embedded in cost calculations, depending on methods used.

Table 13. Summary of Estimates of Wholesale Market Price Impacts of Renewables Developed for RPS

State	Estimated Benefit	Benefit $/MWh of RE	Period	Description	Source
ME	$4.5 million	$2/MWh	2010	Savings for consumers from reduced electricity prices. Extrapolating from a study by ISO-NE, LEI estimated that 625 MW new wind in Maine would reduce wholesale prices by $0.375/MWh of total Maine retail sales.	LEI 2012
MA	$328 million	~$50/MWh	2012	Savings for consumers from reduced wholesale electricity prices.	EOHED and EOEEA 2011
IL	$177 million	$26/MWh	2011	Renewable energy lowers wholesale prices, by $1.3/MWh (all generation) due to low operating costs.	IPA 2013
MI	N/A	N/A	2011	2% decline in wholesale prices attributed to wind generation, net imports, and decrease in load.	Potomac Economics 2012
NY	$455 million*	$5/MWh	Project lifespan	Savings for consumers from reduced wholesale energy and capacity prices.	NYSERDA 2013b; 2013c
OH	Not estimated	N/A	2014	Renewable energy lowers wholesale prices by $0.05-$0.17/MWh (all generation).	PUCO 2013c

*Net present value calculation reported in $2012.

Illinois. IPA's model of the Eastern Interconnection, as described in the Emissions and Human Health section, was also used to calculate wholesale market price reductions. Because wind power does not have fuel costs—it is a zero-marginal cost resource—it can result in reducing wholesale power prices by displacing more expensive generation sources. IPA's modeling shows an estimated average reduction in LMPs of $1.30/ MWh attributable to renewable energy produced in Illinois in 2011. The model estimates an average LMP of $36.40/MWh when Illinois renewable energy fleet is excluded, and $35.10/MWh when it is included (IPA 2013).

Maine. MPUC's consultants, LEI, cited an ISO New England study that estimated average clearing prices for different levels of wind penetration installed in the western part of Maine by 2016 (Coste 2011). In a scenario where there were no transmission constraints, 1 GW of wind reduced wholesale prices by about $0.60/MWh. Assuming a linear relationship between cost reductions and added wind capacity, LEI estimated that 625 MW of new wind in Maine would reduce wholesale prices by $0.375/ MWh. Considering annual retail sales of roughly 12,000 GWh and assuming that the savings are passed 100% to retail consumers, LEI calculated annual savings of $4.5 million for ratepayers from reduced electricity prices (LEI 2012).

Massachusetts. At the direction of the state legislature, the executive offices of Housing and Economic Development (EOHED) and Energy and Environmental Affairs (EOEEA) prepared a report in 2011 on the costs and benefits of various policies, including the state's renewable and alternative portfolio standards. The report notes that there are a number of potential benefits of renewable generation, but bases its calculation primarily on the price suppression benefit resulting from the addition of renewable and alternative energy resources. The study relies on estimates of price suppression effects from the Cape Wind contract proceeding, in which the DPU reviewed estimates provided by various parties. To estimate the RPS benefits, the study assumes price suppression grows linearly in proportion to the amount of renewable energy generation. Using a total benefit value of approximately $50/MWh for the renewable and alternative sources added to the grid each year,[51] the report estimates aggregate benefits of $328 million for CY 2012 (EOHED and EOEEA 2011).

Michigan. In its 2013 report, the MPSC also included information on wholesale market impacts from wind energy in MISO based on a study by the grid operator. The introduction of the Dispatchable Intermittent Resources (DIR) program in June 2011 allowed wind to participate in MISO's real-time energy market like other power resources and set market prices of negative $20/MWh on average, due to low marginal operating costs and PTCs (MPSC 2013). The independent market monitor for MISO reported that two-thirds of the 2% decline in energy prices in 2011 was attributable to a decline in average load, increased generation by "intermittent resources", and an increase in net imports (Potomac Economics 2012).

New York. NYSERDA calculated wholesale price reductions using IPM to model the effect on capacity and energy prices from the addition of renewable energy assets in the Current Portfolio. The average price difference in $/MWh was multiplied by total load levels (adjusted for utilities that self-supply) to estimate consumer savings due to RPS resources. Savings accrue because most load-serving entities in the state have divested of generation resources and procure energy to serve loads from wholesale markets, although wholesale price reduction benefits would not accrue where generation is procured through long-term contracts committed prior to the

[51] The number was taken from the Cape Wind contract proceeding (DPU 10-54 Revised RR-DPU-NG-4).

development. Total net present value of price suppression benefits were estimated at $455 million over the lifetime of the renewable resources (2002-2037) (NYSERDA 2013b; NYSERDA 2013c).

Ohio. PUCO calculated wholesale price reductions for the two scenarios described in the Emissions and Human Health section. In the first scenario, which considers only those projects that are already operational, wholesale prices are reduced by approximately 0.15%, from $32.25 /MWh to $32.20/MWh. In the second scenario, which considers all approved projects, wholesale prices are reduced by approximately 0.51%, from $32.25/MWh to $32.08/ MWh (PUCO 2013c).

While the studies summarized here show estimated reductions in wholesale electricity prices on the order of about $1/MWh or less, the impact on overall reduced costs to consumers can be large since the price suppression effect in any given hour is applied to the entire demand in that hour. Estimates presented above represent price suppression benefits of about $2-$50/MWh of renewable generation. Typically, these wholesale price estimates have been derived through modeling of the electricity system. One difficulty in directly comparing these estimates to costs is that wholesale price suppression is a short term effect that could change over time with changing market conditions. In addition, these estimates focus on energy prices, but do not attempt to assess capacity-related impacts or the need for new transmission or infrastructure investments that may be required with renewable generation. Another consideration is that while consumers benefit from lower wholesale market prices, the reductions represent transfer payments from generators to consumers.

5 Conclusion

This report surveys and summarizes existing state-level RPS cost and benefit estimates and examines the various methods used to calculate such estimates. The report relies largely upon data or results reported directly by electric utilities and state regulators. As such, the estimated costs and benefits itemized in this document do not result from the application of a standardized approach or the use of a consistent set of underlying assumptions.

The report summarizes state-level RPS costs to date and considers how those costs may evolve going forward, given scheduled increases in RPS targets and cost containment mechanisms incorporated into existing policies. The report also summarizes RPS benefits estimates, based on published studies for individual states, and discusses key methodological considerations. These estimates, for example of the social value of carbon emissions reduction and the human health impacts of reduced air emissions, are based on a variety of methodologies and assumptions. In comparison to the summary of estimated RPS costs, the summary of RPS benefits is more limited, as relatively few states have undertaken detailed benefits estimates. Further, for those states that have estimated RPS benefits, most assess only a limited number of impact types; as a consequence, some types of benefits are not reflected in this report.

This survey of RPS costs and benefit estimates across states finds that in the most recent year with data available, costs were estimated to be equivalent to less than 2% of retail rates in 17 states, with 10 of these states having estimated costs equivalent to less than 1% of retail rates. The remaining 8 states have costs that are estimated to be equivalent to 2% to 4% of retail rates, averaging the two estimates for California. A limited number of states have developed quantitative benefits estimates, which vary widely in both methodology and magnitude. Benefits estimates have been most commonly developed for avoided emissions and associated air quality improvements, economic development, and wholesale electricity price suppression effects. Because the reported cost and benefit values may differ from those derived through a more consistent analytical treatment, we do not provide an aggregate national estimate of RPS costs and benefits, nor do we attempt to quantify net RPS benefits at national or state levels.

Estimates of costs are limited by available data and the wide variety of methods and assumptions employed. This analysis focuses on comparing estimated incremental costs, which are most appropriate for assessing RPS policy because they net out costs that would otherwise have been incurred to serve loads if the RPS did not exist, such as the need for other forms of generation. We use a standardized method to derive incremental costs in restructured markets based on REC prices, ACP levels, and compliance obligations. Key limitations of this method include omission of other potential policy costs, a lack of REC price transparency, and incomplete data on long term contracts. While REC prices reflect compliance costs, they do not necessarily reflect the cost of renewable technology deployment because they can be strongly influenced by market supply and demand conditions. In regulated states, comparisons of costs are complicated by our reliance on estimates produced by utilities and regulators, who utilize a wide variety of methods and assumptions.

The primary methods used in regulated states for estimating incremental RPS costs are: 1) to compare the cost of renewable generation to that of a proxy generator (a plant type that is most likely to be displaced by the renewable generation); 2) to compare to wholesale electricity market prices; or 3) to conduct electric system modeling with and without the renewable generation. While the modeling approach can provide a more detailed estimate of the resource mix if an RPS were not implemented, assumptions for inputs can significantly influence results. Simplified proxy methods may provide useful perspective on costs, but yield less comprehensive results. In various approaches, assumptions regarding plant lifetime and methods of annualizing costs are important considerations that can significantly affect estimates. The inclusion of costs associated with pre-RPS renewables can lead to overestimates of RPS costs while inclusion of efficiency and indirect expenditures may make it challenging to directly assess costs resulting from the addition of new renewable generation.

Despite differences and uncertainties in cost methodologies, RPS costs are typically bounded by the presence of policy mechanisms to cap costs. Most states have a way to contain RPS costs, typically through either a cap, based on either retail electricity rates or revenue requirements, or by allowing ACPs. Estimated incremental RPS costs in most states are well below the respective cost caps, although a few states are currently operating at or near them.

RPS costs can be considered in the context of policy benefits, although again there are limitations in the ability to compare estimates. While RPS policies have the potential to offer a variety of environmental and social benefits, often only a few types of benefits have been quantified. States have most commonly attempted to estimate avoided emissions and associated human health benefits, economic development impacts, and savings associated with reductions in wholesale electricity prices; in many cases, these assessments have been required by the legislature or PUC. In some cases, the same impacts may be captured in the assessment of incremental costs. In addition, methodologies and level of rigor vary widely, making comparisons challenging.

Going forward, more could be done to comprehensively assess the costs and benefits of state RPS policies. Instead of looking separately at incremental costs and benefits, future analysis could compare costs and benefits directly within and among states, using a consistent methodology and level of rigor.

In addition to more comprehensive analysis of cost and benefits, additional work could be done to standardize incremental cost calculations within and among states, given that incremental cost calculations are often required by RPS statutes. Efforts within a few states are underway to address standardization of incremental cost calculations; states that have not examined standardization may see the issue arise in the future and be able to learn from the processes and outcomes of existing state standardization efforts.

States in restructured markets may find it beneficial to promote REC price transparency, particularly as those markets move towards greater use of long-term contracting. REC price transparency could be encouraged by requiring RPS-obligated entities to report REC prices on a confidential basis to the PUC; prices could then be publically reported only on an aggregated basis.

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Appendix: State Summaries

Arizona

Arizona's RPS requires 15% of electricity be derived from renewable energy by 2025, with 30% (i.e., 4.5% of total retail sales in 2025) of this energy derived from distributed resources. IOUs and electric power cooperatives serving retail customers in Arizona--with the exception of distribution companies with more than half of their customers outside Arizona--are subject to the standard (DSIRE 2012).

APS and Tucson Electric Power (TEP) fully complied with their CY 2012 requirements, which include a substantial distributed generation component. In 2012, APS reports total RPS procurement of 1,507,021 MWh, or 5.3% of retail sales, with total distributed generation of 503,498 MWh (APS 2013). APS's 2011 reported above-market renewable generation cost, which came from PPAs and utility-owned solar facilities, was $11.28/MWh of renewable electricity, dropping to $9.63/MWh in 2012 (APS 2012; APS 2013).

TEP reports total purchased renewable energy at $4,809,557, which exceeded the target of 279,963,210 RECs representing 3% of its retail energy sales for 2011 (9,332,107 MWh) (TEP 2012). TEP did not list renewable generation cost in MWh in its compliance report.

RPS costs are recovered through a surcharge on customer bills. Average residential customer monthly surcharges in 2012 were $3.15 for TEP, $3.84 for APS, and $4.50 for UNSE/Citizens (ACC 2012a; ACC 2012b; ACC 2012c). The residential tariff surcharges are higher than what is seen in other stares with surcharges, partially reflecting the fact that Arizona's RPS has a substantial distributed generation requirement.

California

California's RPS has a 33% target for all electric retailers by 2020. In 2011, Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric Company (SDG&E) spent approximately $1,017 million, $1,341 million, and $170 million, respectively, on direct RPS procurement, whereas RPS deliveries represented 19.8%, 21.1%, and 20.8% of the utilities' retail sales, respectively (CPUC 2013). In 2011, the utilities' RPS portfolios (in dollar terms) were primarily comprised of geothermal (35%), wind (34%), and biomass (12%). Table 14 provides a summary of California utilities' average RPS costs from 2003-2011. These data represent gross RPS procurement costs.

Table 14. California Utilities' Estimated Average RPS Costs in ¢/kWh (2003-2011)

Utility	2003	2004	2005	2006	2007	2008	2009	2010	2011
Southern California Edison	7.5	7.6	7.6	7.5	8.0	9.3	7.9	8.2	8.5
Pacific Gas and Electric Company	6.5	6.5	6.4	6.6	7.5	8.2	7.0	7.4	7.3
San Diego Gas & Electric Company[52]	5.4	5.3	5.3	5.3	5.2	5.8	5.4	5.9	5.1

Source: CPUC 2013

In California, two sets of incremental cost estimates have been used to compute RPS incremental costs, resulting in average incremental costs ranging from -2.4 ¢/kWh to 4.3 ¢/kWh in 2011.The MPR methodology, developed by the CPUC, is used to determine whether an "RPS contract selected from a competitive solicitation had above-market costs associated with it" (CPUC 2013, p.9). The 10-year and 20-year MPRs for contracts with a 2011 start date are 8.8 ¢/kWh and 10.1 ¢/kWh, respectively, based on 2009 MPR calculations.[53] Using the MPR methodology, incremental cost calculations for 2011 were negative, equaling -2.4 ¢/kWh of renewable energy procured, or -3.6% of average retail rates.

The other set of incremental cost estimates, provided by the utilities, is based on day-ahead CAISO energy market prices and the cost of capacity in the CAISO market (CPUC 2013a). These incremental cost calculations in 2011 were 2.2 ¢/kWh for SDG&E, 3.6 ¢/kWh for PG&E, and 5.3 ¢/kWh for SCE.

The CPUC is currently in the process of developing a cost containment mechanism for the RPS. In 2013, the CPUC proposed using a Procurement Expenditure Limitation (PEL) methodology to calculate RPS containment mechanism, replacing the MPR method, which is composed of a ratio of an IOU's RPS procurement expenditures (actual money spent by the IOU to fulfill its PPAs and operate its facilities over 10 years) to its total forecasted revenue requirement (the initial year equals the IOU's effective revenue requirement, escalated by 2.75% over the course of 10 years) (CPUC 2013).

Colorado

Colorado's RPS has a 30% mandate for IOUs and a 20% mandate for cooperative and municipal utilities by 2020, with 3% of retails sales coming from distributed generation. Cooperative and municipal utilities with less than 100,000 meters are only required to meet 10% renewables by 2020 (DSIRE 2013). Colorado's RPS offers a 1.25 multiplier for projects installed before January 1, 2015 and a 3.00 multiplier for projects installed before July 1, 2015.

[52] SDG&E's RPS cost includes RECs starting in 2009.
[53] The 2011 adopted values are current, but they apply only to RPS contracts with start dates in 2012 and beyond (CPUC 2013).

The major IOUs in Colorado–Xcel Energy (Public Service Company of Colorado) and Black Hills–have had no difficulty meeting targets. In fact, Xcel has been able to procure more renewable energy than required. In 2012, for example, Xcel generated or procured 6.3 million RECs as opposed to the required 3.5 million (PSCO 2013a).

Xcel has been able to buy wind power through PPAs at prices competitive to what it sees for natural gas. Two recent wind PPAs were signed for $27.50/MWh, escalating in future years, with a 25-year levelized cost of $35/MWh (Stanfield 2013b). The estimated incremental RPS costs are determined through scenario analysis that compares the costs and benefits of the current RPS plan to a plan that replaces the new renewable energy with new non-renewable resources available. In 2011, Xcel had the equivalent of 16% of its retail sales from renewable energy (or 20%, when including the 1.25 multiplier for in-state projects), but was only required to have 12% renewable energy (CO PUC 2013).

Colorado PUC rules stipulate that the retail rate impact can be calculated as the difference between the cost of the renewable energy purchases and the cost of new fossil fuel-based energy for generation RPS-related costs and can be recovered through the Renewable Energy Standard Adjustment (RESA) surcharge, which is capped at 2% of annual customer bills. As of 2012, PSCo's 2% monthly customer surcharge was equivalent to roughly $1.44, on average, for residential customers, while Black Hills Energy's average residential customer surcharge was roughly $2.04 (PSCO 2013a; Black Hills 2013). To date, Xcel has spent more than 2%, but deferred the additional spending for collection in later years.

Connecticut

Connecticut's RPS requires each electric supplier and each electric distribution company (EDC) wholesale supplier to obtain at least 23% of its retail load by using renewable energy, in addition to obtaining at least 4% of its retail load by using combined heat and power (CHP) systems and energy efficiency, for a total of 27% by 2020 (DSIRE 2012). Connecticut uses a separate tier for energy efficiency, for which compliance is achieved through the use of credits, and some of the information on prices is available from brokers.

In 2008, in aggregate, 3,070,869 Connecticut eligible RECs were used to comply with the RPS requirements, of which 1,534,981 were Class I RECs. Only 4% of Class I renewable energy is coming from Connecticut, 45% from Maine, 29% from New Hampshire, and the rest from Massachusetts, New York, Rhode Island, Quebec, and Vermont. Approximately 74% of the Class I RECs used for 2008 RPS compliance were obtained from biomass plants, particularly wood, followed by 28% of RECs generated from methane gas from landfill facilities (Department of Public Utility Control 2011).

In 2008, there were 17 electric suppliers and 2 EDCs subject to the Connecticut RPS; 6 suppliers (32%) did not meet the RPS, but this was by slim margins. Two of the state's largest utilities, Connecticut Light & Power Company and the United Illuminating Company, were in 100% compliance with 2008 RPS requirements. Companies that fail to comply with the RPS requirements are required to pay an ACP of $55/MWh for Class I RECs, which is used to offset other ratepayer costs (Department of Public Utility Control 2011). The aggregate ACP paid by all suppliers for 2008 was $113,730.

Findings from the Connecticut Center for Energy, Economic, and Environmental Policy and the Rutgers Economic Advisory Service indicate that future impact of the RPS on Connecticut's electricity prices is between less than 1% and 3.5% of the typical residential electricity bill in 2020. The economic and energy impacts of Connecticut's RPS requirements were estimated using R/ECON Connecticut, an econometric model based on historical data for Connecticut and the United States.

The District of Columbia

The District of Columbia has an RPS requirement of 20% by 2020 that applies to all retail sales in the district. The RPS requirement includes a solar carve-out of 2.5% by 2023. Only systems less than 5 MW in capacity and located within the District of Columbia[54] are eligible for the carve-out (DSIRE 2013). RECs retired to meet the solar carve-out can be used to meet the main RPS requirement as well (DCPSC 2012).

In 2010, energy suppliers reported 100% compliance with the main requirement and 97% compliance with the solar carve-out. In 2011, the Public Service Commission of the District of Columbia (DC PSC) reported that a total of over 469,000 RECs were used for main tier compliance–excluding carve-outs–for a total cost of approximately $820,000 and an average REC price of $1.75. Roughly half of the RECs retired were generated in 2011 while the other half was equally split between 2010 and 2009 (DC PSC 2013).

Since the inception of this RPS, black liquor gasification has consistently been used as the primary source of RECs; black liquor typically costs less than other RPS-eligible resources. Landfill gas and wood waste are the two other most prevalent sources of renewable energy used for compliance in the region. Collectively, these three generation technologies accounted for 94% of total main tier compliance in 2011, and their average costs per REC ranged between $1.42/MWh and $1.94/MWh. That year the solar carve-out requirement was 0.4% and 5,896 SRECs were retired for compliance. In 2011, the average cost of SRECs was $300/MWh. Recent 2013 SREC prices from the Flett Exchange and SRECTrade were around $375/MWh to $386/MWh (DCPSC 2013).The main tier ACP is set at $50 (DCPSC 2013). In 2011, the total reported RPS compliance cost was $2.6 million, of which ACPs totaled $229,500 (most of these payments came from one electricity supplier unable to acquire enough SRECs) (DCPSC 2013).

Delaware

Delaware's RPS requires retail electricity suppliers to purchase 25% of the electricity sold in the state from renewable sources by 2025, with at least 3.5% from solar photovoltaic (PV) (DSIRE 2013). Beginning in CY 2012, the RPS applies to the state's only electric distribution company, Delmarva Power & Light.

In CY 2011, Delaware was in 99% compliance, with a total of 554,259 MWh RECs (15,741 MWh from solar, 517,245 from new non-solar, and 21,273 from existing non-solar resources).

Delmarva Power estimates that total costs to comply with the RPS are $45 million from 2013-2014, increasing to $83 million from 2022-2023 (Delmarva Power & Light Company 2012). As

[54] Alternatively, the systems may be connected to a distribution feeder serving the District of Columbia.

far as rate impacts on customer bills are concerned, Delmarva forecasts that the RPS is likely to affect a typical 1,000 kWh residential monthly bill by \$6.60 in CY 2013; this impact is expected to increase to \$15.15 a month in CY 2022 (Delmarva Power & Light Company 2012).

The total cost cap for Delmarva Power & Light Company is 1% for solar, which includes compliance with PV requirements. If the utility's total retail cost of electricity exceeds 1%, then the RPS requirement for solar may be frozen at the percentage for the year in which the freeze is implemented. The total cost cap for Delmarva Power & Light Company is 3% for eligible energy resources; if the utility's total retail cost of electricity exceeds the 3%, then the RPS requirement may be frozen at the percentage for the year in which the freeze is implemented. Delaware also has an ACP set at \$25-\$80/MWh (DSIRE 2013).

The Department of Natural Resources and Environmental Control (DNREC) is in the process of developing rules for calculating the cost of compliance with the RPS, which may include provisions for "netting" the costs or including costs that are avoided by renewable energy resources, such as air emissions costs. "Netting" RPS avoidance costs of renewable energy may significantly reduce the impact on customer bills (Delmarva Power & Light Company 2012).

Draft regulations specify that the Division of Energy & Climate will determine the cost of compliance, which will then be review by the Director. The Division Director shall then determine the whether to freeze RPS requirements. As part of that determination, draft regulations specify that the Director may consider benefits such as price suppression, savings in health and mortality costs, and economic development benefits from renewable energy deployment in the state. (DE DNREC 2013)

Hawaii

Hawaii's RPS requires each electric utility that sells electricity for consumption in the state to achieve net electricity sales from renewable energy of 15% by 2015, 25% by 2020, and 40% by 2030. Starting in 2015, electrical energy savings from energy efficiency and solar water heating technologies will be excluded from counting towards the RPS. In 2012, 1,276,234 MWh were generated from purely renewable resources, fulfilling 13.9% of the RPS requirement for the Hawaiian Electric Companies consisting of Hawaii Electric Light and Maui Electric Company (HECO).

According to HECO, long-term fixed price contracts for renewable energy are cost-effective compared to avoided energy costs (see Table 15). The Oahu generation cost includes seven PPAs, of which one was biomass generated at approximately 26 ¢/kWh, two for wind at a cost of 21 to 23 ¢/kWh, three for PV between 22 and 23 ¢/kWh, and one for waste to energy at 21 ¢/kWh (HECO 2012).

Table 15. Estimated Avoided Energy Cost in ¢/kWh Purchases from Qualifying Facilities of >100 kW[55]

	Hawaiian Electric Company	Hawaii Electric Light	Maui Division	Maui Electric Company Lanai Division	Molokai Division
On peak	22.697	20.657	19.990	34.669	29.473
Off peak	16.041	15.652	19.318	29.076	26.646

Source: HECO 2012

Kauai Island Utility Cooperative (KIUC) serves the island of Kauai only. In 2012, KIUC's RPS portion that was met by electrical energy generated using renewable energy was 40,793 MWh, which is greater than 50% of the total 2012 10% RPS requirement of 43,315 MWh (KIUC 2012).

By the end of 2012, renewables accounted for 15% of KIUC electricity sales. The 6 MW solar array at Port Allen is the largest solar facility in Hawaii. It supplies almost 10% of KIUC's daytime electrical load and annually produces about 3% of the total energy used on Kauai. Under a 20-year contract, KIUC pays 20 ¢/kWh for solar power.

In 2008, the Hawaii Public Utilities Commission (HPUC) approved a penalty of $20/MWh for any shortfall in procuring renewable electricity to meet the RPS requirements (HPUC 2012). In Hawaii, utilities may petition the HPUC for a waiver of a penalty for failure to meet the RPS if contracts for procuring generation or renewable energy credits are above-market price for other available resources (Stockmayer et al. 2012).

Illinois

Illinois's RPS requires IOUs and alternative retail electric suppliers (ARES) to achieve a 25% RPS target by 2026, of which 75% of the requirement must be from wind, 60% wind for ARES, 1% from distributed generation and thereafter (IOUs only), and 6% from solar in 2016 and thereafter (1.5% of total sales in 2026) (DSIRE 2013). In-state renewable energy is given preference, although out-of-state RE purchases may also count towards compliance.

Renewable energy procurement is done through the Illinois Power Agency (IPA), whose purpose is to develop electricity procurement plans, including for RPS compliance, for IOUs supplying over 100,000 Illinois customers. The IPA plans and administers the competitive procurement processes that result in bilateral agreements between the utilities and wholesale electric suppliers (DSIRE 2013). In 2010, IPA solicited bids for 20-year long-term power purchase agreements (LTPPAs) to purchase up to 2 million MWh of renewable energy and the associated RECs each year, representing approximately 3.5% of the overall portfolio. Under these contracts, a single price was set for the bundled product (energy plus REC) with a 2% per annum cost escalator over the term of the contracts.

REC prices shown in Table 16 are calculated from the average cost of RECs and energy procured by IPA. For the LTPPAs, where RECs are purchased with energy ("bundled"), IPA estimates the REC cost by subtracting the cost of conventional generation from the total cost of

[55] The methodology for the avoided cost calculation was developed prior to 1995 and is currently publically unavailable in an electronic format.

the renewable energy contract (the price of energy and RECs bundled together). In 2011, the IOUs were in 100% compliance with RPS obligations.

Table 16. IPA Reported Costs of Unbundled RE Cs and Conventional Supply (June 2009-May 2013)

Company	RECs (¢/kWh)	Conventional supply (¢/kWh)
ComEd	0.8	3.4
Ameren	0.7	3.4

Source: IPA 2013

Note: REC costs are the average actual cost of RECs procured by IPA; for RECs procured with energy ("bundled") under the 2010 LTPPAs, IPA estimates the REC cost by subtracting the energy price from the bundled cost.

Starting in 2007, the RPS costs are limited to either 2.015% of the amount paid per kWh in 2007, or the amount paid in 2011, whichever is greater (DSIRE 2013).

Iowa

Iowa's RPS requires its two IOUs, MidAmerican Energy and Alliant Energy Interstate Power & Light (IPL), to own or contract for a combined total of 105 MW of renewable generating capacity, of which MidAmerican Energy contributes 55.2 MW (52.57% of demand) and IPL contributes 49.8 MW (47.43% of demand) (DSIRE 2013). In 2001, a voluntary goal of 1,000 MW of wind generating capacity by 2010 was established. By the end of 2012, Iowa's installed wind capacity totaled 5,133 MW (IWEA 2012). The two utilities have fully met their obligations since 1999.

As of 2011, the Iowa Utilities Board (IUB) staff estimated that 19-20% of all electricity generated in the state comes from wind (IUB 2011), much of which is used to meet RPS policies in surrounding states.

Kansas

Kansas's Renewable Energy Standard (RES) requires the state's IOUs and cooperative utilities to generate or purchase 10% of their electricity from eligible renewable resources in the years 2011-2015, 15% in the years 2016-2019, and 20% by 2020. Unlike most other states, Kansas's standard is based on generation capacity (i.e., generally the gross capacity owned or leased by a utility less the auxiliary power used to operate the facility) (DSIRE 2013).

Kansas public utilities have already complied with the 10% threshold, and are on their way to meeting the 15% requirement, primarily from wind resources. In 2012, there was oversupply of RECs in the region for two of Kansas's larger utilities: Empire generated an excess of 291.9 MW and Westar generated an excess of 280.8 MW. Importantly, for renewable capacity generated in Kansas, utilities are awarded an additional 10% credit toward their requirements, thus incentivizing utilities to keep the renewable projects within the state (as of November 2012, there were 19 wind projects currently in operation or under construction).

Costs for Kansas are measured on a gross basis. The KCC estimated statewide 2012 RPS gross costs of about 0.16 ¢/kWh, meaning that the RPS counts for about 0.16 ¢/kWh of the 9.2 ¢/kWh retail electricity cost in 2012 across the state, or about 1.7% (KCC 2013). The Kansas RPS places a 1% cap on the rate impact of compliance based on gross compliance costs. Given that the statewide impact of 1.7% exceeds the 1% cap on rate impact, it can be assumed that at least one utility has compliance costs exceeding the cap; however, utility specific cost information is held confidential by the KCC.

Additional gross cost information on wind projects in Kansas was estimated by Polsinelli Shughart and Kansas Energy Information Network. The study estimated the gross costs of new wind power in Kansas to be between $35 and $45/MWh (Anderson et al. 2012).

Maine

Maine's RPS requires IOUs to supply at least 10% of their total electric sales using electricity generated from renewable sources classified as Class I (resources that have come online after September 1, 2005) by 2017 and for each year thereafter. Existing renewable energy resources are classified as Class II and must supply at least 30% of total electric sales by 2017 (DSIRE 2013).

In 2010, the RPS requirement for new renewable resources (Class I) was 3%, or close to 333,000 MWh. The cost of purchased Class I RECs ranged from $5.76/MWh to $43/MWh with a total cost of $8.1 million (LEI 2012). The average reported procurement cost of Class I RECs was $24/MWh. Only two out of 30 suppliers chose to pay the ACP at the rate of $62/MWh for a total cost of $22,500 in 2010 (LEI 2012).

Over 80% of purchased RECs were produced within the State of Maine and biomass has been the major resource for satisfying the Class I RPS requirements. Renewable resources located in Maine contributed significantly to RPS Class I compliance in Connecticut and Massachusetts, accounting for over 30% of the New England Class I RPS compliance requirement in 2009 (LEI 2012).

London Economics International LLC (LEI) calculated the compliance costs for Maine's Class I RPS and found that in 2010, the cost was 0.07 ¢/kWh. LEI calculated the RPS retail rate impact on Maine's consumers by multiplying the RPS percent requirement by the annual electricity retail sales and the market price of RECs. To assess the potential impact on retail rates if RPS policies and/or REC market prices change, LEI implemented an analytical "what if" consideration for both a higher RPS requirement as well as lower REC prices based on the 2010 compliance cost scenario. Based on the 2010 compliance scenario, the ratepayer impact of the current 3% RPS was found to be 0.57% of the current average retail rate, or 37¢/month for residential customers, assuming a REC price of $24/MWh. Ratepayer impacts for the RPS at 10% was estimated to be 1.90% or $1.24/month for households assuming REC prices remain at $24/MWh, and 1.07% of the current average retail rate and 70¢/month, assuming REC prices of $13.50/MWh (LEI 2012).

Maryland

Maryland's RPS requires all utilities and competitive retail suppliers to sell a minimum percentage of renewable energy at the retail level. In 2013 that requirement was 7.95%, which will grow to 18% in 2022. Electricity suppliers must obtain 2% of retail sales from solar resources by 2020. In 2013, Maryland enacted an offshore wind carve-out of up to 2.5% of retail sales in 2017 and beyond; the actual requirements of the carve-out will be developed by the Maryland Public Service Commission (DSIRE 2013).

Electricity suppliers that fail to comply with the annual requirement must pay an ACP of $40/MWh for main tier requirements. For solar generation, the ACP declines from $400/MWh in 2011 to $50 in 2023. Payments go into the Maryland Strategic Energy Investment Fund (MSEIF), which is used to spur the creation of new renewable energy sources in the state (PSCM 2013).

In 2011, electricity suppliers in Maryland submitted more than 4.6 million RECs for compliance, roughly 15,000 above the requirement. The total cost was $14.6 million, of which $98,520 came from ACPs. Roughly 40% of the retired RECs were generated in 2011, 35% were in 2010, and 25% were in 2009 (PSCM 2013).

For the non-solar part of the main tier, black liquor represented 33% of the RECs retired in 2011, while small hydro was 26%, wind was 14%, and waste wood was 12%. Black liquor and small hydro are generally considered low-cost resources. Approximately 39% of the RECs were generated in Virginia compared to 14% generated in Maryland (PSCM 2013).

Massachusetts

Massachusetts's RPS retail load obligation from renewable resources was 6% in 2011, of which 0.1627% must be met with solar. The RPS increases annually by 1% and is mandated to reach 15% by 2020 (DOER 2013a).

In 2011, the total retail load obligation was 49,386 GWh, of which the 5.8% Class I obligation (net of the 0.1627% solar carve-out obligation) was 2,883 GWh. Of this, 87% came from 2011 generation while 9% came from banked RECs from a compliance surplus in 2009 and 2010 and 4% from ACPs. Out of 37 suppliers, 14 did not acquire enough RECs to meet the target, but they met their compliance by paying the ACP of $62.13/MWh for 106,203 MWh for a total ACP payment of $6,598,386 (DOER 2013a).

RPS costs in Massachusetts are capped through use of an ACP. Table 17 lists the 2013 ACP rates for several classes of renewables.

Table 17. ACP Rates for the 2013 CY (in $/MWh)

RPS Class I	RPS Class I Solar Carve-Out	RPS Class II Renewables	RPS Class II Waste Energy
$65.27	$550.00	$26.79	$10.72

Source: DOER 2013b

In 2011, RPS Class I RECs came from wind (47%), landfill methane fueled power plants (32%), and biomass-fired power plants (15%). The remaining supply came from anaerobic digester plants, hydroelectric plants, and PV arrays. Geographically, Maine's wind supplied 28% of RECs, New York's landfill methane plants and wind supplied 26%, wind farms in adjacent Canadian provinces supplied 13%, New Hampshire (mostly biomass) supplied 13%, Massachusetts (mostly landfill methane) supplied 11%, and other New England states supplied the balance (DOER 2013a).

In 2013, Fitchburg Gas and Electric Light Company, along with National Grid, NSTAR Electric Company, and Western Massachusetts Electric Company, collectively entered into PPAs to acquire their *pro rata* share of the total renewable energy output and RECs from six wind energy projects, with a combined capacity of 565 MW (MPUC 2013). If approved, utilities will pay an average price of less than 8 ¢/kWh over the course of these contracts compared with projected prices of about 10 ¢/kWh for coal, 11 ¢/kWh for nuclear, and 14 ¢/kWh for solar (Ailworth 2013). The commercial operation dates associated with these projects range from November 2014 to December 2016 and total generation is expected to reach 4 million MWh (MPUC 2013).

Michigan

Michigan's RPS requires all utilities to generate 10% of their retail electricity sales from renewable resources by 2015, 15% by 2020, and 30% by 2035. There are additional renewable energy capacity requirements for large utilities above 1 million retail customers, such as Consumers Energy and Detroit Edison, which must respectively procure 200 MW and 300 MW by the end of 2013 and 500 MW and 600 MW by 2015. In addition, the RPS allows utilities to use energy efficiency and advanced cleaner energy systems to meet a limited portion of the requirement (DSIRE 2013).

According to projections, providers are on track to meet the 2015 requirement, with renewable generation expected to account for 9% of power supply in 2015 and the remainder to be fulfilled with RECs banked from previous years. The first RPS CY in Michigan was 2012, but in 2011, electric providers were well positioned to meet the 2012 standard. In 2012, electric providers reported a total of 11,501,525 available RECs and 116,570 Advanced Cleaner Energy Credits, equivalent to about 4.4% of retail sales (MPSC 2013).

The Michigan Public Service Commission (MPSC) approved contracts in 2011 and 2013 for new wind capacity that have levelized gross costs of $61-$64/MWh and $50-$60/MWh, respectively (Englom 2013). The renewable energy weighted average gross cost of these contracts over the life cycle of the systems is $91/MWh.[56]

[56] Renewable energy cost data are based on levelized costs that are provided in the renewable energy contract approval process.

Based on estimates from DTE Energy and Consumers Energy, from 2008-2012 the rate impact from the RPS is approximately 0.3–0.6 ¢/kWh for residential customers (or 2–4%) and 0.1–0.3 ¢/ kWh (or 1–3%) for business customers (Consumers Energy, DTE Energy, and MEGA 2012). Utility providers can recover the RPS incremental costs of compliance through MPSC's approval of a monthly surcharge per meter on customers' bills. Consumers Energy's surcharge is currently 52¢ for residential; between 90¢ and $14.40 for small commercial; and between $3.60 and $90.00 for large commercial and industrial customers. At the end of 2012, DTE Energy's surcharge was set at the statutory maximum of $3.00 for residential; $16.58 for small commercial; and $187.50 for large commercial or industrial (Consumers Energy, DTE Energy, and MEGA 2012). Citing lower-than-expected renewable energy project costs, Consumers Energy has proposed to eliminate its surcharges as of the July 2014 billing cycle (Consumers 2013c).

Minnesota

Minnesota's RPS requires Xcel Energy (Northern States Power) to obtain 31.5% by 2020, including 1.5% solar. Other utilities have separate requirements. Public utilities are required to obtain 26.5% renewable energy by 2025, including 1.5% solar. Non-public utilities are required to obtain 25% renewable energy by 2025 but do not have a solar requirement (DSIRE 2013).

In 2012, Northern States Power met the RPS requirement of 13% with 5,637,456 MWh of RECs. Northern States Power has generated surplus RECs each year since 2008. The REC bank provides them the flexibility to defer the installation of new renewables and use banked RECs to comply with RPS obligations (Xcel Energy 2011).

Of the fourteen utilities that submitted compliance reports, eight stated that complying with the RPS has resulted in little or no additional costs, if not slight savings for customers. Northern States Power reported that its renewable investments have been cost-effective and actually kept prices in 2008-2009 about 0.7% lower than they would have been without renewables. Northern States Power calculated the rate impact by determining the difference between the costs of implementing and not implementing the RPS, and then by determining the cost difference on a ¢/kWh basis by dividing the costs by total retail sales (Xcel Energy 2011).

Six utilities, including Great River Energy (GRE), reported that their efforts to comply with the policy are leading to increased costs for customers. GRE found that its wind energy purchases increased retail customer bills by about 1.6%, or about $1.50/month for an average residential customer (Haugen 2011).

Missouri

Missouri's RPS requires IOUs to procure renewable energy or RECs for 15% of electricity sales, including 2% from solar by 2021. Municipal utilities and electric cooperatives are not subject to the standard. RECs can be used to meet up to 10% of the total obligation and must be generated in the CY in which they are retired. In-state renewable energy generation receives a multiplier of 1.25 compared to out-of-state generation.

In 2011, Ameren Missouri, Empire, KCP&L, and KCP&L Greater Missouri Operations (GMO) were 100% in compliance with the RES. In 2012, Ameren acquired a total of 319,489 RECs under a 15-year PPA with the Pioneer Prairie Wind Farm (Ameren Missouri 2013).

Missouri's RPS requires IOUs to offer rebates of at least $2/W for customer-sited solar electric systems of 25 kW or less beginning in 2010. Systems of 100 kW or less qualify for rebates on the first 25 kW of installed capacity (DSIRE 2013). The largest electric utility in the state, Ameren Missouri, was expecting to reach the limit on allowable expenditures on renewables by the end of 2013, but reached a settlement with state regulators to continue solar rebates to customers who install solar systems until expenditures reach $91.9 million (Tomich 2013). Of the $91.9 million, $22 million in rebates has already been paid out, helping support about 11 MW of solar in the state (Tomisch 2013). The Missouri Public Utilities Commission (MPUC) can excuse utilities from the RPS if compliance costs exceed standard increases retail electricity rates by more than 1% (DSIRE 2013).

Montana

Montana's RPS requires load serving entities with 50 customers or more to obtain renewable energy equivalent to 15% of retail sales by 2015. Utilities that fail to fulfill their requirements must pay a penalty of $10/MWh. Alternatively, utilities may seek a short-term waiver from compliance. Excess RECs may be carried over for up to two subsequent CYs. Between 2012 and 2014, public utilities must purchase all the RECs and electricity generated by community projects, which are defined as renewable power plants less than 25 MW, majority-owned by local people (DSIRE 2013).

In CY 2011, a total of 691,872 RECs were needed for compliance in Montana. Eligible electricity providers retired 694,986 RECs and $481 was paid in ACPs (the lowest amount paid in ACPs since the inception of the program). Excess RECs will be carried over for subsequent CYs (MT PSC 2012).

Nevada

Nevada's RPS requires utilities to obtain 25% of their total electricity sales from renewable sources by 2025. The solar carve-out is set at 5% through 2015, but increases to 6% of the portfolio requirement starting in 2016. Energy efficiency qualifies as an eligible resource for RPS, but is limited to 25% of the requirement in 2013 and 2014, declining over time and becoming ineligible to meet targets in 2025 and beyond (DSIRE 2013).

In addition, NV Energy (formerly Nevada Power and Sierra Pacific Power) is required to retire 800 MW of coal-fired electric generators by 2020 and acquire 900 MW of power from cleaner facilities, including at least 350 MW from renewable energy facilities (DSIRE 2013). The utility must issue a request for proposals for 100 MW of generating capacity from new renewable energy facilities each year from 2014-2016. The final 50 MW of generating capacity from new renewable energy facilities must be operational by 2022. These requirements are separate from the 25% RPS requirement, but portfolio energy credits (PECs) associated with these projects can apply to meet the RPS requirements (DSIRE 2013).

In 2012, both Nevada Power and Sierra Pacific Power exceeded RPS compliance requirements, supplying a total of 4,225,710 MWh and 2,317,174 MWh respectively, including energy efficiency savings. The estimated total 2013 compliance cost comprised of purchased power, REC procurement, and incentives and rebate programs is $273,230,993 and $139,052,000 for Nevada Power and Sierra Pacific Power, respectively (NV Energy 2013). This resulted in gross RPS costs of $65/MWh for Nevada Power and $60/MWh for Sierra Pacific Power. In Nevada Energy's 2012 integrated resource plan (NV Energy 2012), a long-term avoided cost rate of $30/MWh is calculated. If this avoided cost rate is subtracted from the gross RPS costs, the resulting costs are $35/MWh and $30/MWh, for Nevada Power and Sierra Pacific Power, respectively.

The bulk of expenses for Nevada Power were for purchased power and REC procurement ($195 million). Sierra Pacific Power's spending was more evenly split between purchased power and RECs ($77 million), and rebate programs for solar, hydro, and wind ($56 million).

New Jersey

New Jersey's RPS requires each electricity provider to procure 22.5% of the electricity it sells from qualifying renewables by 2021. There is a solar specific carve-out of 4.1% by 2028 in addition to a 1,100 MW offshore wind resource requirement (DSIRE 2013).

In 2010, public utilities retired a total of 3,627,069 Class I RECs; compliance using RECs was nearly 100%, with only one utility paying three ACPs. Class I REC prices were reported at an all-time low of $2/MWh by the end of 2010. For the solar target, 123,717 MWh of SRECs were retired in 2010 while suppliers paid the solar ACP of $693/MWh for the remaining 47,373 MWh (NJ BPU 2011).

New Jersey's Office of Clean Energy estimates the total cost of compliance with the 2010 RPS was $122 million, with the solar requirement estimated to have cost $109 million. The solar costs included $32.8 million of SACP payments, plus more than $76 million in SRECs. The Class I requirements are estimated to have cost approximately $11 million. In 2010, the cumulative weighted average price of SRECs was $615.50/MWh (The Office of Clean Energy and in New Jersey's Board of Public Utilities 2011).

New Hampshire

New Hampshire's RPS requires electricity providers to procure 24.8% of retail sales in 2025 from renewable resources. Of that total, 15% must come from new renewable facilities and 0.3% from solar generators. In 2013, ACPs for new renewable requirements are $55/ MWh for electric technologies, including solar, and $25/ MWh for thermal (DSIRE 2013).

For the 2012 CY, the electricity providers were required to procure 3% new renewables and 0.15% solar. ACPs totaled $9.3 million, equivalent to 260,957 MWh of RECs, or roughly 44% of the total estimated requirement (NHPUC 2013).

According to the New Hampshire PUC (2011), the total cost of compliance (including RECs and ACPs) was $18,601,556, with the average cost per kWh of $0.0017, meaning that a typical residential ratepayer (using about 500 kWh/month) would pay about 85¢/month (NH PUC 2011).

For regulated utilities, 98% of compliance was met with RECs, and 2% with ACPs. For competitive electricity suppliers, 67% of compliance was met with RECs, and 33% with ACPs (NH PUC 2011).

New Mexico

New Mexico's RPS requires that IOUs have 15% of retail electricity sales from renewable energy by 2015 and 20% by 2020. It also requires that the targets be met with diverse resources, including 30% wind, 20% solar, 5% other technologies, and 3% distributed generation (by 2015). Rural electric cooperatives must maintain renewable energy at 5% of retail sales by 2015 with annual increases at a rate of 1% to 10% in 2020 and beyond. (DSIRE 2013).

Southwestern Public Service Company (SPS) purchases bundled wind energy from two New Mexico wind facilities; the cost of the RECs is estimated at $1.35/MWh, per a settlement agreement in SPS's last base rate case (SPS 2012). SPS calculates the projected cost of RPS compliance as the REC cost multiplied by the MWh requirement. For 2014, they estimate the cost of compliance for wind generation at $499,709. To calculate the costs bundled solar energy, SPS estimates the REC costs at $10/MWh; for other solar facilities, the incremental cost is the above-avoided costs (SPS 2012). The total cost of solar for 2014 is projected to be $11,792,771 (SPS 2012).

In 2013, SPS is complying with the RPS by entering into three 20-year PPAs for nearly 700 MW of wind. If the PPAs are approved, assuming customer use of 800 kWh/month, the retail rate is projected to decrease by 60¢ (NM PRC 2013b).

The New Mexico Public Regulation Commission (PRC) has set a cost cap in order to temporarily exempt utilities from meeting the RPS if they spend more than 3% of their gross annual revenues on renewables (Stanfield 2013). All three of the state's IOUs have either requested waivers from their total RPS obligations and/or have requested modifications to their specific set-aside requirements, in order to remain within the rate impact cap. The Public Service Company of New Mexico (PNM) cap is 2.50% and 2.75% in 2013 and 2014, respectively. PNM's cost cap methodology was based on projected revenues for 2013 and 2014 from electric charges to retail customers and separately calculated revenue contributions attributable to the customers subject to the rate impact cap (PNM 2013).

North Carolina

North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requires IOUs to supply 12.5% of retail electricity sales from eligible energy resources by 2021. Municipal utilities and electric cooperatives must meet a target of 10% eligible energy resources by 2018.The overall target for renewable energy includes technology-specific targets of 0.2% solar by 2018, 0.2% energy recovery from swine waste by 2018, and 900,000 MWh of electricity derived from poultry waste by 2014 (DSIRE 2013).

Progress Energy Carolinas Inc. (PEC) indicated that it will be able to comply with the 2012 solar set-aside (0.07% of 2011 retail sales), but will be unable to meet its 2012 swine waste and poultry waste set-aside requirements. Utilities in North Carolina jointly filed to have the swine and poultry waste set-aside requirements delayed until 2014; the North Carolina PUC staff has agreed with this recommendation (NC PUC 2013).

RTI International and La Capra Associates, Inc. (2013) calculated the rate impact of REPS compared to the conventional portfolio by dividing the difference in total generation costs by projected North Carolina retail sales. The result is an estimate of the ¢/kWh impact customers can expect to see in their bills as a direct result of REPS. For a typical North Carolina residential customer, assuming use of 1,151 kWh of electricity/month, the monthly estimated savings amount to almost 50¢ in 2012 and more than $1.00 by 2024 (RTI International 2013).The data show that over the 20-year period of REPS, electricity rates are expected to be lower than they would have been if North Carolina had continued to use only conventional generation sources, resulting in $173 million in generation cost savings compared to the conventional portfolio by 2026.

New York

New York's RPS requires IOUs to procure 30% of electricity sales from renewables by 2015, of which 20.7% will be from existing renewable energy facilities, and 1% is expected to be met through voluntary green power sales.

The New York State Energy and Research Authority (NYSERDA), which procures renewables for the utilities through its main tier and customer-sited tier programs, requires 10.4 million MWh of renewable energy annually in 2015. By the end of 2012, NYSERDA already achieved the main tier and customer-sited tier 2015 targets at 47% and 33%, respectively (NYSERDA 2013a).

The aggregate MWh weighted average award price (RECs only) from the seven Main Tier solicitations is $19.25/ MWh. The seventh solicitation, completed in 2011, yielded the highest weighted average award price ($28.70/ MWh). The third solicitation, completed in 2008, resulted in the lowest award price ($14.75/MWh) (NYSERDA 2013a). Wind power is the predominant generating technology in the Main Tier, capturing 1,653 MW of new renewable capacity under contract, of which 1,561 MW was in operation at the end of 2012 (NYSERDA 2013a).

NYSERDA conducted a cost-benefit analysis to determine the renewable energy premium (incentive cost) and the retail rate impact from the RPS. The renewable energy premium was calculated by modeling the costs to construct, operate, and maintain a renewable facility over its useful life and comparing those costs to revenue streams from the market and other sources, such as federal incentive programs. If revenues from renewable sources exceed the costs, the investment is cost-effective. Then, the retail rate impact is calculated by dividing the total above-market costs (as determined by the premiums paid) by total annual electricity expenditures in New York (NYSERDA 2013b). The maximum annual net rate impact of the RPS was 0.12% over the study period (2002-2037). Retail rates are expected to decrease by about $23 million over the study period compared to a total retail expenditure level of $256 billion for New York ratepayers (NYSERDA 2013b).

Ohio

Ohio's Alternative Energy Portfolio Standard (AEPS) requires that electricity retailers, excluding municipal utilities and electric cooperatives provide 25% of their electricity from alternative energy by 2025. Half must come from wind, hydropower, geothermal, and biomass resources. Of that 12.5%, 0.5% must come from solar energy. At least half of the renewable energy must be generated in-state and energy efficiency qualifies for fulfilling the requirement (DSIRE 2012).

In 2011, the total statewide AEPS compliance obligation net of the solar carve-out was approximately 1.3 million MWh, which slightly exceeded the required REC compliance obligation. The total solar carve-out obligation, including deficiencies from previous years that were rolled forward to 2011, was 42,089 MWh, with nearly 100% of the requirement having been satisfied (PUCO 2013).

The Ohio Public Utilities Commission (PUCO) calculated the weighted average REC cost for electric distribution and electric service companies based on the information provided in the utilities' 2011 compliance reports (see Table 18).[57]

Table 18. The Weighted Average Cost/REC for Ohio's Electric Distribution Utilities and Electric Service Companies in 2011

Category	Electric Distribution Utilities (average $/REC)	Electric Service Companies (average $/REC)
Ohio Solar	228.7	307.7
Other Solar	157.8	148.1
Ohio Non-Solar	110.5	20.8
Other Non-Solar	19.4	5.97

Source: PUCO 2013

Several utilities recover administrative costs and the cost of REC purchases through an alternative energy resource rider (AER-R) on customer bills, which may not exceed 3% of retail rates. PUCO's cost cap methodology consists of comparing incremental costs (not including ACPs which utilities cannot recover from ratepayers) to "reasonable expected costs of generation," which may not necessarily include the net retail revenue requirement, depreciation, tax gross-up, and a rate of return (Stockmayer et al. 2012, p. 157). Utilities may not count construction or environmental expenditures of generation resources that are passed on to consumers through a surcharge against the 3% cap (Stockmayer et al. 2012). In 2012, the RPS monthly surcharge for residential customers was $5.76 and $0.77 for FirstEnergy (Ohio Edison, Cleveland, Toledo Edison) and Dayton Power & Light, respectively (DP&L 2011; Ohio Edison 2011; Cleveland Electric Illuminating Co. 2011; Toledo Edison Company 2011).

In 2013, PUCO studied the changes in wholesale electricity prices and generator emissions that are likely to occur as a result of the AEPS. In the scenario which only includes operational

[57] Compliance markets continue to evolve, so prices provided in Table 19 should not be interpreted as indicative of current market prices.

projects, wholesale electricity prices are estimated to be reduced by approximately 0.15% in 2014 (PUCO 2013).

Oregon

Oregon's RPS requires the largest utilities to supply 15% of their retail electricity sales from renewable sources by 2015, 20% by 2020, and 25% by 2025. In addition 20 MW-AC of solar PV systems (sized 500 kW to 5 MW) must be installed by 2020. Utilities with less than 1.5% of state load must meet a 5% RPS, while utilities with 1.5% to 3% of state load must meet a 10% RPS by 2025. However, utilities that buy into or sign a contract for new coal power are subject to the "large utility" standards. At least 8% of Oregon's retail electrical load will come from small-scale renewable energy projects with a capacity of 20 MW or less by 2025 (DSIRE 2012).

Oregon's two largest utilities, PacifiCorp and Portland General Electric Company (PGE), have met 100% of the 2011 RPS compliance obligations. In 2011, PacifiCorp reported 650,729 MWh of banked RECs that were used to meet the RPS. At the end of 2011, PacifiCorp owned 1,031 MW of wind-powered generation capacity and had entered into PPAs for the output from 749 MW of wind capacity (Pacific Power 2012).

For CY 2012, PGE reported that it would meet the RPS with 140,800 unbundled RECs.[58] PGE's projected annual revenue requirement is $1,709,111,606 and the total cost of RPS compliance for CY 2012 is $3,859,811. The cost of compliance as a percentage of the revenue requirement is 0.23% (PGE 2013). PacifiCorp calculated the incremental cost of compliance at -.60% for 2011, meaning that the RPS lowered costs (Pacific Power 2012).

The Oregon PUC established the ACP at a rate of $50/MWh for 2011. In addition, there is a rate impact cap. If compliance costs exceed 4% of the utility's annual revenue requirement for a CY, electric utilities are not required to fully comply with the RPS during that year (DSIRE 2012).

Pennsylvania

Pennsylvania's Alternative Energy Portfolio Standard (AEPS) requires electric distribution companies and electric generation suppliers to supply 18% of electricity using alternative energy resources including energy efficiency measures by 2021. A solar requirement of 0.5% is included in the Tier I requirement under the same schedule. For non-solar resources, the ACP is fixed at $45/MWh. Solar ACPs are calculated as 200% of the sum of the average cost for solar Alternative Energy Credits (AECs) plus the levelized value of non-Pennsylvania upfront rebates for solar PV systems (DSIRE 2012; PPUC 2013).

For CY 2012, the AEPS requirement was 0.0325% for solar, 3.4675% for non-solar Tier I resources, and 6.2% for Tier II. The average price of unbundled AECs for solar was $180.39, $5.23 for non-solar Tier I resources, and $0.17 for Tier II. In total, the annual compliance requirement was 13,877,487 MWh, fulfilled by Load Serving Entities (LSEs) at an estimated total cost of $35,867,115.[59] In CY 2012, no ACPs were required. The three main technologies

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[58] The total cost of bundled RECs was redacted due to the proprietary nature of information.

[59] The average AEC price for each tier was used in this estimate, even though average prices were calculated by PPUC using only data from the subset of AECs for which there was a known price.

used to generate Tier I AECs in CY 2012 were wind, wood and solid biomass, and black liquor gasification, which contributed with 50%, 12%, and 11% of the total retired AECs, respectively. Pumped-storage hydropower was used to generate 65% of the retired Tier II AECs in CY 2012, followed by waste coal, with 16.5% (PPUC 2013).

Rhode Island

Rhode Island's RES requires the state's retail electricity providers to supply 16% of their electricity sales from renewable resources by the end of 2019. The requirement began at 3% at the end of 2007, and then increases an additional 0.5%/year through 2010, 1%/year from 2011 through 2014, and 1.5%/year from 2015 through 2019. Aside from the RES, "The Long-Term Contracting Standard for Renewable Energy" requires electric distribution companies enter into long-term contracts for 90 MW in capacity by 2014 from new renewable energy facilities, of which 3 MW must come from in-state solar facilities (DSIRE 2013).

In CY 2011, the statewide RES was met with 27.3% biomass, 12.2% wind, and 5.0% hydro resources. Seventeen entities had Rhode Island RES obligations and a total of 201,129 MWh were retired for RES compliance. A total of 84,402 MWh or 29.6% valued at $5,243,896 of RES compliance was met with ACPs at a rate of $62.13/MWh (PUC 2011).

Narragansett Electric incurred costs of $8.43 million to meet the 2001 new and existing RES obligations. In 2010, the RES charge was .00123¢/kWh representing a rate impact of 62¢/month for an average residential payer. As of April 2011, the RES charge turned into a bill credit of .00031¢/kWh or approximately .15 ¢/month (PUC 2011). In 2012, the average annual RES charge was estimated to be .00182¢/kWh, resulting in a rate impact of $1.08/month.

Texas

Texas's RPS requires all municipally-owned utilities, generation and transmission cooperatives, and distribution cooperatives that offer customers a choice of retail providers; retail electric providers (REPs); and IOUs that have not been unbundled under deregulation to acquire a total of 5,880 MW of renewable energy resources by 2015 (about 5% of the state's electricity demand), including a target of 500 MW of renewable energy capacity from resources other than wind, and 10,000 MW by 2025 (DSIRE 2013).

Renewable energy generation totaled 29.9 million MWh in 2013, with wind accounting for 28.9 million MWh (ERCOT 2014). In CY 2012, the total RPS requirement for all retail entities, after adjustments for previous true-ups as required by the Texas Public Utility Commission (PUCT), was 12,119,614 RECs (PUCT 2012).

As of 2012, Texas penalizes entities $50/MWh if a utility falls short of compliance with the RPS targets (Stockmayer et al. 2012). However, with over 12,000 MW of renewable generation capacity, Texas has exceeded its goal of 10,000 MW by 2025.

Washington

Washington's RES requires all electric utilities that serve more than 25,000 customers to obtain 15% of their electricity from new renewable resources by 2020 and pursue "cost-effective" energy conservation (DSIRE 2013).

In CY 2012, Puget Sound Energy (PSE) met initial 2012 RES requirements of 3% with more than 635,958 RECs and could already potentially reach the 9% 2016 goal if it uses its excess RECs. According to the utility's 2012 compliance report, the incremental costs of eligible renewable resources were $27.83 million (PSE 2012). PacifiCorp plans to pursue compliance in through the purchasing of RECs while PSE and Avista have developed new renewable energy generation resources and are purchasing RECs. All three IOUs have met the 2012 target.

The incremental cost of a renewable resource is defined as the difference between the levelized cost of the renewable resource compared to an equivalent non-renewable resource. PSE's calculation of the cost of non-renewable resources included capacity cost, energy cost, and imputed debt. If the incremental cost is greater than 4% of its revenue requirement, as established by the Washington UTC, then a utility will be considered in compliance with the RES.

The Renewable Northwest Project and NW Energy Coalition found a lack of consistency in the incremental cost calculations employed by the three utilities (Stanfield 2013a). The costs of compliance, as reported by the utilities in 2012, were $15.73/MWh for PacifiCorp, $20.35/MWh for Avista, and $43.76/MWh for PSE. These costs made up the following portions of the revenue requirements for each utility: 0.61% 0.80%, and 1.36% respectively. The Washington UTC is addressing cost standardization as it considers revisions to its RPS rules (Docket UT-131723).

Wisconsin

Wisconsin's RPS has a goal of 10% of all electric energy consumed in the state to be supplied by renewable energy by the end of 2015 (Wis. Stat. § 196.378). Each electric provider in the state has its own RPS requirement, ranging from 6.64% to 22.47%, depending on how much renewable electricity it provided in 2003 (PSCW 2013). Collectively, utilities in Wisconsin had met three-quarters of the 2015 RPS requirement by 2010. Also, all 118 electric providers met their individual 2010 RPS requirement (PSCW 2012).

In 2012, the Public Service Commission of Wisconsin (PSCW) estimated the costs of statewide RPS compliance to be between 1% and 1.1% of the utilities' revenue requirements for calendar years 2008 through 2010. Using two similar methods, the PSCW compared the levelized cost of electricity produced by the renewable energy sources added after the enactment of the state's RPS with the marginal cost of energy in the Midwest regional energy market (PSCW 2012).

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Do state renewable portfolio standards promote in-state renewable generation?

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ABSTRACT

Several US states have passed renewable portfolio standard (RPS) policies in order to encourage investment in renewable energy technologies. Existing research on their effectiveness has either employed a cross-sectional approach or has ignored heterogeneity among RPS policies. In this paper, we introduce a new measure for the stringency of an RPS that explicitly accounts for some RPS design features that may have a significant impact on the strength of an RPS. We also investigate the impacts of renewable portfolio standards on in-state renewable electricity development using panel data and our new measure of RPS stringency, and compare the results with those when alternative measures are used. Using our new measure, the results suggest that RPS policies have had a significant and positive effect on in-state renewable energy development, a finding which is masked when design differences among RPS policies are ignored. We also find that another important design feature – allowing "free trade" of REC's – can significantly weaken the impact of an RPS. These results should prove instructive to policy makers, whether considering the development of a federal-level RPS or the development or redesign of a state-level RPS.

1. Introduction

In the United States, power plants are responsible for approximately 40 percent of the nation's carbon dioxide emissions, leading environmental and other interest groups to target this sector as they seek to reduce emissions in response to concerns of global climate change. The lack of action by the federal government has led some state and local governments to fill this void with a variety of policy approaches (Engel and Orbach, 2008). One of the most common state-level policy instruments, and the object of significant attention, is known as a renewable portfolio standard (hereafter, RPS). An RPS is a policy that ensures that a minimum amount of renewable energy (such as wind, solar, biomass, or geothermal energy) is included in the portfolio of electric-generating resources serving a state. RPS regulations generally impose obligations that increase over time. The stated intent of these policy measures is usually some combination of increasing the diversity, reliability, public health and environmental benefits of the energy mix.[1] As of April 2009, 30 states[2] and the District of Columbia have passed renewable portfolio standards.

While RPS policies all share several key features, they vary dramatically in design across states. These design differences have been carefully detailed by Berry and Jaccard (2001); Wiser et al., (2005); Wiser et al., (2007); and Wiser and Barbose (2008). However, econometric analyses of the effectiveness of RPS policies have largely ignored this heterogeneity in RPS design. For methodological convenience, previous empirical analyses have treated RPS policies as identical or have characterized the differences among them in an overly simplistic manner. A primary argument in the present study is that without properly accounting for the wide heterogeneity we see in RPS policies, empirical studies of their effectiveness may result in very misleading conclusions. Moreover, careful analysis of these differences and their influence on RPS effectiveness can afford policy makers an opportunity to improve the effectiveness of RPS policies through their redesign.

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[1] Some proponents of RPS policies have also claimed that they can provide employment benefits (the often-discussed "green jobs"), or generate learning economies important for the development of renewable technologies, though these questions are not examined in the present paper.

[2] The 30 states are AZ, CA, CO, CT, DE, HI, IA, IL, MA, MD, ME, MI, MN, MO, MT, NC, NH, NJ, NM, NV, NY, OH, OR, PA, RI, TX, VA, VT, WA, and WI. Virginia and Vermont have passed unconventional policies that have been deemed by some to be "optional". However, unlike the voluntary policy, of say, North Dakota, the policies in both Virginia and Vermont contain credible commitments that provide real incentives for renewable development. Nonetheless, we have also performed the empirical analysis presented in this paper with alternative classifications of the Virginia and Vermont policies, and the results are qualitatively identical. These results are available upon request.

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In this paper, we develop a measure for the strength of an RPS. This measure explicitly considers some key design features that could potentially affect the magnitude of the incentives for developing new renewable capacity. This new measure suggests that some seemingly aggressive RPS policies in fact provide only weak incentives, while some seemingly moderate RPS policies are in fact relatively ambitious. It follows that in any analysis addressing the question of whether RPS policies are effective drivers of investment in renewable electricity capacity, imposing uniformity on the policy is inappropriate.

Based on the new measure, we present the most rigorous statistical analysis of RPS policies to date. For the purposes of this paper, we define effectiveness of an RPS policy as the extent to which it increases investment in in-state renewable electricity capacity. We find that RPS policies do in fact lead to a statistically significant increase in in-state renewable electricity development. This result stands in sharp contrast to those when the differences in RPS stringency are ignored or measured in an overly simplistic manner, as has been done in previous studies.

The remainder of the article is organized as follows. In Section 2, we provide a brief overview of the research done on RPS policies to date. In Section 3, we present some background on RPS policies, key dimensions of heterogeneity in these policies, and propose a new measure for the stringency of such policies. In Section 4, we present an empirical framework for estimation of the effectiveness of an RPS in promoting renewable energy development. Section 5 describes the data and compares different measures for RPS stringency. In Section 6, we present the results of our estimations. Finally, in Section 7, we conclude.

2. Literature review

Rigorous study of renewable portfolio standards has been rare. In this section, we outline the existing literature on these relatively new policies. In this paper, our primary concern is not the efficiency of RPS policies, but rather their effectiveness—which is a necessary (though not sufficient) condition for efficiency. Furthermore, while first-best efficiency is obviously ideal, the effectiveness criterion may ultimately be more useful when other more efficient policies being considered (usually cap-and-trade or a carbon tax) are politically infeasible. Nonetheless, we review the literature on both questions in this section.

State-level RPS policies are often seen by economists as a sub-optimal policy for two key reasons. First, since the most significant environmental benefits from RPS legislation come from the internalization of *global* externalities, a regional approach runs the risk of inducing welfare losses in the regulated region without incurring environmental benefits, as the damaging pollutants can continue to be produced elsewhere. For example, Bushnell et al. (2007) argued that the effectiveness of such local initiatives is limited due to a leakage or reshuffling problem and claimed that RPS policies are "largely symbolic unless they facilitate change beyond their local regions". Second, since many states require that the renewable electricity be generated in-state, the principle of allowing the cost of pollutant reduction to be minimized by allowing these reductions to occur where they are least costly is violated.

Two recent papers have developed theoretical models to examine the cost-effectiveness of RPS policies. Palmer and Burtraw (2005) perform numerical simulations to predict the impacts of a *national* RPS, and find that it raises electricity prices, but that it is not as cost-effective as a cap-and-trade policy for reducing carbon emissions. Fischer and Newell (2008) develop and calibrate a model that predicts that an RPS-like policy is a sub-optimal policy whether the goal is reducing carbon emissions or promoting technological progress. A third paper, (Michaels 2007), though lacking a formal model, is also extremely critical of the oft-proposed federal RPS, arguing that it is an inefficient way to achieve any of the policy objectives often attributed to an RPS. Further, the article's author argues that the record of state implementation of RPS policies has, thus far, been largely symbolic.

Nonetheless, and perhaps in part because they are perceived to address several political goals at once, state-level RPS policies have proliferated. Lyon and Yin (2008) examine the political economy behind these policies, and find that renewable energy potentials (measures of the strength of the wind and solar resources in a state), Democratic majorities in the state legislature, and organization of the renewable industry are all significant antecedents of a state-level RPS. Interestingly, they do *not* find that high levels of existing renewable development make a state more likely to adopt an RPS.

Distinct from, though not orthogonal to, the question of efficiency is the question of effectiveness. Namely, do RPS policies achieve their primary stated goal of increasing renewable capacity and generation in the states in which they are passed? The most prominent studies have not included complete statistical analyses and have concluded that the policies are either ineffective (Bushnell et al., 2007) or "largely symbolic" (Michaels, 2007).

As far as we know, only three (Menz and Vachon, 2006; Adelaja and Hailu, 2008; Kneifel, 2008) studies have employed econometric analysis to empirically identify the impacts of RPS on renewable energy development. These studies, however, have taken a rather blunt approach. Using cross-sectional data, Menz and Vachon (2006) and Adelaja and Hailu (2008) both establish a positive correlation between existence of an RPS and renewable development, but the use of cross-sectional data precludes any conclusions regarding causality. Furthermore, these studies treat RPS's as being uniform across states. Menz and Vachon (2006) and Adelaja and Hailu (2008) both use a binary RPS variable, which abstracts away from the very real heterogeneity across RPSs.

Kneifel (2008), on the other hand, uses a panel data approach and finds that RPS policies do not lead to an increase in renewable capacity in a state if the requirement is based on generation, as is common in most states.[3] His study does in fact differentiate among RPSs by using their nominal requirements, which are the RPS goals that are written into the laws, as his measure of the strength of the policies. However, as evidenced in this paper, using nominal requirement as the measure of an RPS fails to capture some important design features that are decisive for RPS effectiveness and therefore may also lead to misleading conclusions.

The current study attempts to further the literature in two ways. First, we construct a measure that incorporates the most important design features of an RPS and therefore more accurately assesses the strength of an RPS; secondly, we perform a panel data analysis and demonstrate how misleading conclusions might result when the heterogeneity of design is ignored or over-simplified as has been done in previous studies.

3. Background

RPS policies, which are the central focus of this paper, differ from other policies designed to incentivize renewable energy installation and generation, in that they are essentially minimum quantity mandates, though with varying degrees of flexibility. All strive to ensure that a minimum amount of renewable energy is included in the portfolio of electric-generating resources serving

[3] Given that most of the relatively few capacity-based policies are enforced on the basis of generation, using capacity conversion factors that are usually publicly known, we argue that Kniefe differentiation between capacity- and generation-based policies is a false dichotomy.

the state. Furthermore, all the RPS policies we examine here clearly specify the path of the requirement over time, and generally build to a final standard at some distant point in the future (for example, Michigan's RPS, passed in October 2008, has an ultimate target of 10 percent by 2015, with intermediate requirements of 2 percent by 2012, 3.3 percent by 2013, and 5 percent by 2014).

The fact that these requirements are written into the laws themselves provides researchers with an obvious measure for the strength of an RPS; we refer to this as the *nominal requirement.*[4] Although straightforward, using nominal requirement as a measure neglects a sizeable amount of policy heterogeneity that could potentially have significant impact on the strength of an RPS. Previous research on RPS design (Berry and Jaccard, 2001; Wiser et al., 2005; Wiser et al., 2007; Wiser and Barbose, 2008) suggests that the heterogeneity in three distinct dimensions have the greatest importance. We examine each in turn, and discuss how we account for them in our analysis.

3.1. Coverage

Wiser et al. (2005) have argued that a well-designed RPS should ideally apply equally and fairly to all load-serving entities in a state. However, in practice, there are vast differences in coverage, as different types of utilities are treated differently by some of the policies. For example, in Maryland and five other states (Iowa, Texas, Hawaii, Minnesota, and Wisconsin), all utilities, including investor-owned utilities, power marketers, rural cooperatives, and municipal cooperatives, are required to comply. However, other states have provided partial exemptions in meeting RPS requirements, either to entire classes of utilities, or in some cases, to individual utilities. In Montana, the RPS applies only to investor-owned utilities, which generate only 45 percent of the electricity that is sold in the state. Five other states (Connecticut, Pennsylvania, Arizona, Illinois, and Colorado) have exemptions of a similar magnitude, such that less than 60 percent of the electricity market in those states is covered by RPSs.

3.2. Existing capacity

Another design feature that could affect the effectiveness of RPS is whether the RPS allows generation from existing renewable resources to fulfill the requirements, or whether the standard must be filled with generation from new investments in renewable resources. These obviously have different effects—requiring new resources creates a stronger incentive for new development. Allowing generation from existing assets to "count" will weaken the incentive, and furthermore may allow windfall profits to accrue to those utilities that own existing renewable generating capacity.

States vary greatly in this aspect. While some states, including Arizona, Massachusetts, Montana, and Vermont, only allow generation from new assets to count towards the policy, most states allow generation from all units that existed at the time the legislation was passed. Many states, including Delaware, Maine, North Caroline, New Hampshire, New Mexico, New York, Oregon, Virginia, and Washington, allow generation from some, but not all, existing units. For example, Washington's RPS states, "New renewable generation resources are defined as having first gone into commercial operation after 12/31/97. Renewable generation units that entered service before that date may not account for more than 1 percent of total retail electricity sales in any compliance year." When eligible existing capacity is large compared to RPS requirements, the strength of an RPS would be significantly overstated if we used the nominal requirement as the main measure, because the policy-induced incentive to install new renewable generating capacity is relatively small.

In order to take into account the heterogeneity in coverage and existing capacity, and thus more accurately capture the size of the new incentive generated by these policies, we propose a new variable, *INCRQMTSHARE*:

$$INCRQMTSHARE_{it} = \frac{NOMINAL_{it} \times COVERAGE_{it} \times SALES_{it} - EXISTING_{iT}}{SALES_{it}} \tag{1}$$

where $NOMINAL_{it}$ is the nominal requirement in state i in year t, $COVERAGE_{it}$ is the proportion of sales of the utility industry in state i covered by the RPS at time t, $SALES_{it}$ is the total retail sales in state i in year t, and $EXISTING_{iT}$ is the renewable generation in year T that, if generated in later years, would be eligible to fulfill the RPS requirement in state i. T is the date the RPS legislation or mandate is enacted.[5] This new variable, *INCRQMTSHARE*, thus represents the "incremental percentage requirement", or the mandated increase in renewable generation in terms of the percentage of all generation. For the remainder of the paper we refer to it as the *incremental requirement.*

One key challenge in deriving *INCRQMTSHARE* is to calculate $EXISTING_{iT}$, the amount of eligible *existing* renewable generation. The difficulty is due to the fact that state policies differ not only in *whether* existing capacity is eligible, but also in *which* technologies are counted as "*renewable*". We calculate this variable state by state based on each state's definition of "renewable".[6] Thus, three cases arise in the calculation of *EXISTING*: (1) when existing capacity/generation is not allowed, *EXISTING*=0, but (2) when all existing capacity/generation is allowed, *EXISTING* is equal to the renewable generation from existing capacity in period T. However, in the third case, when states allow existing generation only in certain cases, we need to take a case-by-case approach. For example, in the state of Washington (mentioned above), we define existing renewable generation as the renewable generation in year 2006 from plants installed between 1998 and 2006 (the year Washington passed its RPS) plus the minimum of either (a) the 2006 renewable generation from plants installed in or before 1997 or (b) 1 percent of electricity sales in 2006.[7]

[4] This, to a certain extent, is the approach taken by Kneifel (2008). Kneifel (2008) takes the target requirement in a number of years after enactment, and linearly interpolates backwards to the enactment date of the policy to obtain the requirement for each year after enactment. For example, a policy enacted in 1996 with a sales requirement of 1.0% beginning in 2000 would be linearly interpolated to be 0.2% in 1996 and increase by 0.2% each year until it reaches 1.0% in 2000. We argue that this is a strong and ultimately unnecessary assumption. First, all states stipulate the requirement to be enforced in every year until the ultimate goal is reached, and these do not generally follow linear patterns. Second, given the large fixed costs associated with renewable energy generation and the learning curves often thought to accompany renewable energy development, ii is not clear why we should expect producers to develop renewable capacity in a linear manner, even in years when the time path of the requirement is not explicitly laid out. In this paper, we start from the actual scheduled requirements in each state.

[5] If a policy was passed during the first 6 months of the year, T is set to the previous year, otherwise T is the year in which the policy was passed. Regardless of how T is set, we always consider the RPS to become active, in the sense that it enters into the decision-making calculus, in year T+1.

[6] Note that this state-by-state calculation that take varying technologies into account is only performed for the variable *EXISTING*. For the dependent variable, we use a uniform definition of renewable technologies that is explained below.

[7] We recognize that there is an implicit assumption that the amount of generation from existing capacity will continue to be the same for every year after T. This could be violated if renewable capacity is decommissioned after year T, or if, for example, renewable capacity was online, but not operating at full capacity in years prior to T. However, given the relative newness of most renewable-generating capacity and the low operating costs associated with most renewable technologies, this assumption should have minimal effects, whether on our proposed measures or our regression results.

3.3. REC trading

Most RPS policies are enforced through a credit-trading mechanism. When electricity is generated from a renewable source in states that have a renewable energy credit program, there are two resulting products - the electrons that are fed into the grid, and the environmental attributes associated with producing reduced-carbon or carbon-free electricity. In most states, these environmental attributes are accounted for in the form of renewable energy credits, or REC's. Each REC represents one MWh of electricity generated from an eligible renewable energy resource. In some cases, the REC's are bundled with the electricity that they are associated with – this is often the case when an independent power producer has contracted, *ex ante*, to sell the electricity to a given utility. But in some cases, the REC's are instead retained by the independent power producer, and presumably are sold at a later point in time. At the end of a compliance year, the administrator of the program calculates each utility's required amount of renewable generation, based both on the legislated percentage and the share of state's sales belonging to that utility. A utility then has a specified amount of time to purchase the REC's necessary to meet its requirement if it is "short". Treatment of REC's varies across states, and the way these REC's are treated should result in variation of the impact of an RPS policy.

- Some states, including California, Iowa, Illinois, and Hawaii, simply do not allow REC trading or out-of-state REC trading. In these states, the obligated utilities are required to meet a certain standard through their own generation or through power purchase agreements.
- Some states allow out-of-state REC's, but heavily incentivize in-state generation. This is usually done either by creating set-asides, where a certain portion of a utility's obligation must be met with in-state REC's, or multipliers, where in-state REC's get extra credit. For example, in Arizona, a MWh of electricity generated from in-state renewable capacity is credited as 1.5 REC's, whereas the same amount of electricity generated out-of-state is credited as normal.
- Some states impose very restrictive conditions on the eligibility of out-of-state renewable generation, which in essence disallows out-of-state generation. For example, in Texas, out-of-state resources are technically eligible to generate Texas REC's, but the output of the facility must be readily capable of being physically metered and verified in Texas by the program administrator.
- Finally, some states allow free trade of REC's and provide no preferential treatment to in-state REC's.

RPS policies that fall into the first three categories listed above are presumably adopting such provisions in an effort to ensure that any economic and environmental benefits (for example, avoided emissions or "green jobs") resulting from RPS passage do not leak across the border to other states. Without these in-state constraints, utilities may purchase either renewable electricity or REC's from out-of-state resources, therefore mitigating the strength of an RPS in promoting in-state renewable development.[8]

[8] Some analysts (see, e.g., Wiser, 2006) have raised the possibility that imposing in-state-requirements may raise the question of violating U.S. Constitutio Interstate Commerce Clause. This is a valid concern but beyond the scope of this paper.

3.4. Penalty or alternative compliance payment

Another design difference among state RPSs is the treatment of non-compliant energy producers. Some RPS policies, including those in Texas, California, Connecticut, Montana, Washington, and Wisconsin, explicitly impose a financial penalty for noncompliance. For example, in Texas, any utility that fails to meet its obligations under the RPS must pay a penalty equal to the lesser of $50 or 200 percent of the average cost of credits traded during the year *for each MWh it falls short*. In some other states,[9] the RPS instead establishes a mechanism called an Alternative Compliance Payment (ACP), which serves a similar function. For example, in Massachusetts, a retail electricity supplier may meet its RPS obligations (in whole or in part) for any compliance year by making an ACP, rather than by investing in renewable capacity or purchasing REC's. The ACP rate was set at $50/MWh for 2003, and in each subsequent compliance year, the state's Department of Energy Resources is required to adjusted the rate up or down according to the previous year's Consumer Price Index.[10] While they are expressed in different terms, explicit penalties and ACP's should, one expects, have similar effects—they both effectively set a cap on the cost of complying with the RPS. In most of the states that have either an explicit penalty or ACP in place, the level of financial incentive for compliance is of a similar magnitude to those of Texas and Massachusetts.[11] However, nearly half of the states[12] with RPS policies have no such financial mechanisms.

The effect of an ACP or penalty on the effectiveness of an RPS in driving investment in in-state renewable capacity is unclear. One might think that the explicit specification of either a penalty or ACP gives the RPS "teeth": it makes explicit the consequences for a utility who fails to meet its RPS obligations, and thus provides strong incentives to comply with the RPS. However, an explicit penalty or ACP also establishes an upper bound to the negative consequences of non-compliance—it renders the regulatory contract more complete, and this in a sense limits the downside risk to the utility who chooses not to comply.

4. Empirical framework

The primary objective of this paper is to determine the effectiveness of state-level RPS policies in incentivizing investment in new renewable energy. Alternatively put, to what extent can the recent growth in renewable capacity in the 50 states be attributed to RPS policies?

In order to accurately answer this question, we exploit a lengthy panel of data that allows us to control for unobserved state and year heterogeneity. This is akin to a change-in-changes approach—with state and year fixed effects we control for existing differences among the states as well as exogenous technological progress, giving us consistent coefficient estimates. We estimate several models of the form

$$RENEWSHARECAP_{it} = \alpha_i + \gamma_t + \xi Z_{it} + \delta W_{it} + \beta X_{it} + e_{it} \tag{2}$$

where *RENEWSHARECAP* is the percentage of generating capacity in a state that is non-hydro renewable, α_i represents a

[9] As of February 2009, these include MA, ME, WI, NJ, RI, PA, MD, DC, DE, and NH.

[10] The adjusted ACP rate for 2008 is $58.58/MWh.

[11] Two states that have this mechanism charge amounts significantly lower than the others, who are generally around $50/MWh. The penalty in Montana is $10/MWh, and in Maryland, the ACP is either $15 or $20, depending on the 'technology tier'. The findings reported in this paper do not depend on whether or not we treat Montana and Maryland as having a penalty/ACP.

[12] These include IA, MN, NV, AZ, NM, CO, NY, HI, VT, IL, VA, NC, MO, and OR.

state-specific intercept, γ_t represents year fixed effects, Z_{it} represent other state policies that are designed to encourage renewable investment, and W_{it} represents various social and economic variables that might have an impact on the development of renewable energy. Finally, X_{it} is a measure for the RPS policy that varies both within and between states. In some specifications, we interact X_{it} with one of three variables thought to impact the effectiveness of an RPS; one is a dummy variable indicating the existence of an in-state requirement, the second is a dummy indicating that the RPS contains a penalty or ACP, and the third is a measure of how dependent a state is on electricity generated in other states. Because the error terms are likely to be correlated across time within a state, and because we expect the variance to differ by state, we estimate standard errors that are clustered at the state level.

We construct our dependent variable, the percentage of generating capacity in a state that is non-hydro renewable (*RENEWSHARECAP*), using data we discuss in Section 5. X_{it} takes different forms in different specifications; in addition to the nominal requirement and incremental requirement measures discussed above, we also use:

- *RPS*—a binary variable that equals 1 if a mandatory RPS law is effective in a given year, and 0 otherwise. [13] If the legality of an RPS was in dispute (as was the case in IA until 1997), we set *RPS*=0. This is similar to the measure used in Menz and Vachon (2006) and Adelaja and Hailu (2008).
- *RPSTREND*—a state-wise cumulative sum of *RPS*, denoting the number of years that the RPS has been effective.[14] Menz and Vachon (2006) use an analogous measure in some specifications.

In addition to RPS policies, states have also developed and implemented many other policy instruments to encourage installation of renewable generation. We include the following alternative policies in Z_{it} as controls:

- One popular alternative policy is known as a mandatory green power option, under which each utility in the state is required by law to offer its customers the choice of opting to "buy" green power. Consumers opt to pay a premium on their electricity bills, and then the utility must procure enough generating assets or RECs to provide an amount of renewable electricity equal to the amount purchased by those consumers who have chosen this option. *MGPOPTION* is a binary variable that equals 1 if such a law exists in that state and year. As of April 2009, eight states have a mandatory green power option law.
- Another type of policy designed to encourage development of renewable electricity is known as a public benefits fund. These are state-level funds established and maintained by the state public utility commissions in order to support energy efficiency and renewable energy projects. The funds are collected either by charging consumers a small amount, or by requiring payments from the utilities themselves. *PUBBENFUND* is a binary variable that equals 1 if, in a given year, a state maintains a public benefits fund that has as part of its mandate the support of renewable energy projects, and 0 otherwise. As of late 2008, 19 states maintain a public benefits fund that supports renewable energy.
- A third type of policy designed to encourage development of renewable electricity is called net metering. Net metering allows for the flow of electricity from consumer-sited installations back to the grid, so that excess generation at such installations can defray the cost of a customer's bill. These laws provide an additional incentive for small, customer-sited generation. *NETMETERING* is a binary variable that equals 1 if, in a given year, a state has a net-metering law on the books. As of late 2008, 42 states have such a law in place.
- The last type of policy we control for in this paper is referred to as interconnection standards. These are standards that facilitate the contracting process, making it easier, at both the technical and procedural level, for customer-sited generation to be installed. *INTERCONSTAND* is a binary variable that equals 1 if a state has codified interconnection standards to facilitate customer-sited renewable energy installation. As of late 2008, 37 states had such laws on their books.

Besides these policy variables, we also include some social and economic variables in the regression analysis, as they might be thought to have either a direct impact on the development of renewable energy, or indirectly by making the adoption of RPS policies more likely.

- *Electricity price*: Electricity price, *ELECPRICE*, could influence demand for renewable energy resources. On one hand, high electricity prices may reflect the need for the state to seek out alternative energy sources and ensure a viable long-term energy supply, implying that such states would be more likely to develop renewable energy. On the other hand, it may be more difficult to pass on the extra costs of shifting to renewable energy to customers when electricity prices are already high. This suggests that renewable energy could face more resistance in states with high electricity prices. The predicted sign of the overall effect is ambiguous. We use lagged prices so that this regressor is predetermined with respect to the dependent variable.
- *State income*: The transition to renewable energy may cause an increase in electricity prices. States with higher incomes will be more capable of affording the increased price, and therefore are presumably more likely to develop renewable resources. To account for this, we include the median income for 4-person families in each state from 1993 to 2006 in the analysis, which is denoted as *STATEINC*.
- *League of conservation voters (hereafter, LCV) scores*: In states where citizens have stronger environmental preferences, there may be higher demand for renewable energy development. Following previous studies (e.g. Maxwell, Lyon and Hackett, 2000), we use the average LCV scores of Senators and Representatives in each state, *LCVSCORE*, as a proxy for the environmental preferences of the citizens in the state. Each year, the LCV selects environmental issues that exemplify the environmental agenda with the help of a panel comprising the main US environmental groups. The organization then creates an index by counting the number of times each representative or senator in Congress votes favorably for the "environmental agenda" (e.g., tropical forest conservation or fighting global climate change). The index ranges from 0 to 100, with 100 representing a record of voting with the environmental agenda in all cases.
- *Net import of electricity*: A state that is heavily dependent on the import of electricity may have stronger incentives to develop renewable energy to increase the diversity of its energy mix and reduce its energy dependence. To take this confounding factor into account, we include *IMPORTRATIO*, a lagged measure of whether states import or export power, in

[13] We set *RPS*=1 if the law became effective on or before 30 June of that year. This is the coding rule we adopted for any policies evaluated in this paper. We also experimented with setting this variable equal to 1 if an RPS had just been passed, rather than in effect, and found qualitatively similar results.

[14] To date, no RPS has been repealed.

all specifications.

$$IMPORTRATIO_{it} = \frac{SALES_{i,t-1} - GENERATION_{i,t-1}}{SALES_{i,t-1}} \quad (3)$$

In some specifications, we include the interaction term between *IMPORTRATIO* and *INCRQMTSHARE* to see whether a state's response to an RPS depends on the relative abundance of its existing electricity supply.

We include *RECFREETRADE* in some regressions. This is a binary variable that equals 1 if two conditions are met: (1) the state allows its RPS obligations to be met with REC's, and (2) it treats out-of-state REC's no differently from in-state REC's. This variable equals 0 either if the RPS does not allow REC trading, or if it allows only or strongly favors in-state REC trading[15]. We include this binary variable and its interaction with *INCRQMTSHARE* in order to evaluate the extent to which imposing an in-state-requirement renders an RPS less effective in promoting in-state renewable energy development.

In some specifications, we also include *NEIGHBOR*, which is meant to capture the size of the new market for renewables resulting from RPS implementation in neighboring states. This will allow us to control for possible spillover effects. The measure is constructed as follows:

$$NEIGHBOR_{it} = \frac{\sum_{a}^{A} INCRQMT_{at} \times RECFREETRADE_{at}}{SALES_{it}} \quad (4)$$

where A denotes the number of states adjacent to state i, and $INCRQMT_{at}$ is the numerator of equation (1) for state a.

Finally, we include *PENALTYACP* in some regressions. This also is a binary variable which is equal to 1 if either penalty or ACP is to be imposed in case of noncompliance and 0 otherwise. We include this binary variable and its interaction with *INCRQMTSHARE* in order to evaluate to what extent providing a financial penalty or ACP may render an RPS more or less effective in promoting in-state renewable energy development.

5. Data

In this section, we describe the data that is used to create the measures laid out in Section 3 and to perform the analysis described in Section 4.

As discussed above, one key contribution of this paper is the development of a new measure for the strength of an RPS. Once this variable is constructed, we can compare our measure with the more commonly used "nominal" measure. For this purpose, the key task is to calculate $INCRQMTSHARE_{it}$ as defined in Eq. (1), which requires information on each state's electricity market and RPS policies.

For variables measuring the relative size of the electricity industry in each state, $SALES_{it}$, we employ publicly available data on electricity sales (EIA-861) from the Energy Information Administration (EIA). EIA data are also critical in the construction of existing eligible renewable generation, $EXISTING_{it}$. We obtain annual generation data at the generating unit level from the EIA-906 data files.

We construct an analogous measure based on generation rather than capacity, and refer to it as *RENEWSHAREGEN*. This is used primarily in our interpretation of the coefficients (see Section 6); it is less suitable as a dependent variable because the EIA altered its definition of renewable energy in 2000.

To code the RPS policies, we use data from a variety of sources. The Union of Concerned Scientists (hereafter, UCS) maintains a database[16] on the design and implementation of existing state standards. Another excellent database that was very helpful in our data collection efforts was DSIRE, the Database of State Incentives for Renewable Energy[17]. We referred to both databases in our coding of the RPS variables, and when necessary, referred to the actual legislation and/or PUC rules to resolve any discrepancies or missing information. The variables *PENALTYACP* and *RECFREETRADE*, described above, are based on information contained in these sources. Other RPS-related variables include:

$NOMINAL_{it}$, the nominal percentage requirement as written into the law. Every RPS law has an explicitly defined requirement path that evolves over the years. For the handful of states for which the law is coded in absolute capacity terms, rather than as a percentage of generation, we multiply by a constant, called a capacity conversion factor[18], that accounts for the intermittent nature of the most popular renewable technologies, then divide by retail sales in a given year, in order to convert this variable to be in the same units across all of our data.

$COVERAGE_{it}$, the proportion of retail sales in a state-year that can be attributed to entities that are required to comply with the RPS. We use EIA-861 data to calculate the proportion of retail sales in each state that are undertaken by each utility or class of utility[19]. These weights are then combined with data from the laws themselves in order to obtain this variable.

$EXISTING_{iT}$, is the amount of renewable generation in the year prior to the enactment of the RPS policy. We decide what types of existing renewable generation are eligible from the UCS and DSIRE database, and then refer to generating unit-level data from EIA-906 in order to aggregate generation from existing eligible plants in year T.

We derive $INCRQMTSHARE_{it}$ based on Eq. (1). We finish with a balanced panel of $50 \times 14 = 700$ observations, one for each state-year from 1993 to 2006.

Table 1 shows nominal requirements and incremental requirements in 2006 for the 16 states that had a binding standard in that year. The differences between nominal requirement and incremental requirement are striking. We also rank the states based on nominal requirement and incremental requirement, and the correlation between either the measures themselves or their respective ranks is not statistically different from zero. The two measures are clearly not synonymous.

This table clearly demonstrates the potential pitfalls if the incorrect measure of policy stringency is applied in empirical analysis surrounding questions of RPS impact, regardless of the dependent variable. We argue that our new measure is more accurate, as it explicitly accounts for several key design features that affect the effectiveness of an RPS. It is not hard to imagine that studies on the effectiveness of RPS policies will be highly dependent on the choice of measure employed.

Fig. 1 illustrates this point more vividly. In two states that have the strictest *nominal* requirements, Maine and California, the passage of an RPS appears to have had little positive impact on the amount of renewable capacity in the state. After Maine's first RPS (with a 30% requirement) was written into law in September

[15] Or, of course, if the state does not have an RPS policy.

[16] http://go.ucsusa.org/cgi-bin/RES/state_standards_search.pl?template=main

[17] http://www.dsireusa.org

[18] These state-specific capacity conversion factors are often either explicitly written into the legislation, as is the case in TX, or implicit from the history of the RPS, as is the case in IA, where part of the afore-mentioned legal dispute centered around the question of whether 105 MW of wind would satisfy the RPS, or whether 260 MW – an amount of renewable generation that would displace 105 MW of conventional capacity – was required under the law. When the capacity conversion factor was not available, we used 0.35.

[19] We find minimal change in these shares over the 7 years for which we have data, so we use 2006 data to construct these weights.

Table 1
Comparison of measures of RPS stringency in 2006.

State	Nominal requirement (%)	Incremental requirement (%)	Rank of nominal requirement	Rank of incremental requirement
ME	30	0	1	14
CA	14.31	0	2	14
HI	8	1.02	3	8
NV	6	0.38	4	12
WI	5.69	1.23	5	7
NM	5	4.33	6	1
NJ	4.58	2.77	7	3
MN	4.36	2.77	8	2
TX	2.04	1.62	9	6
MA	2	1.72	11	5
CT	2	1.8	10	4
PA	1.5	0	12	14
AZ	1.05	0.62	13	10
MD	1	0.05	14	13
IA	0.86	0.67	15	9
NY	0.81	0.49	16	11

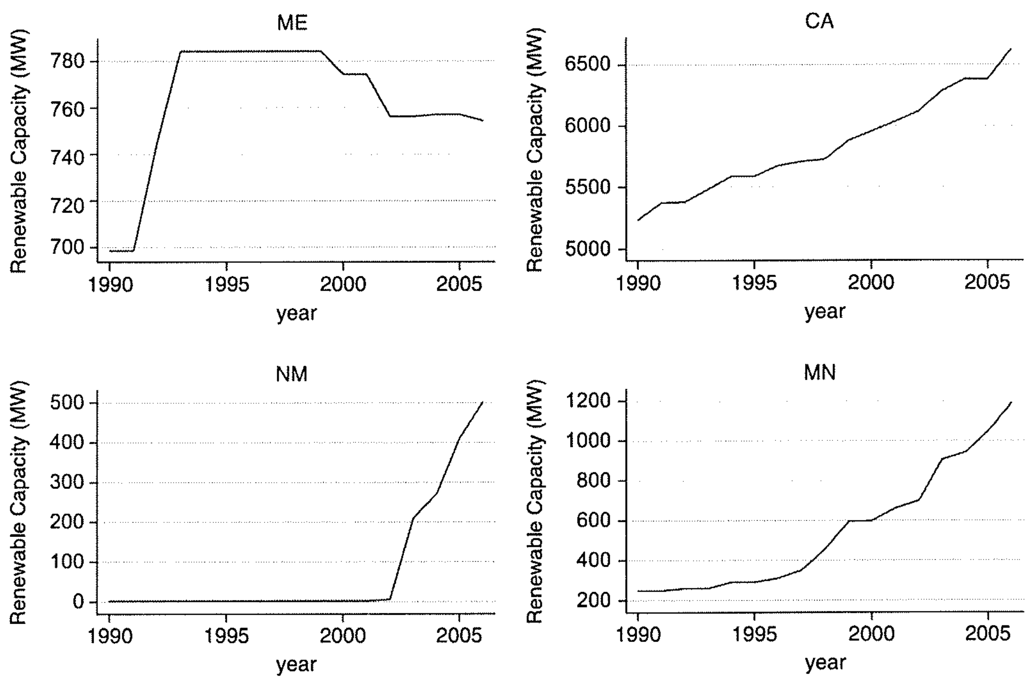

Fig. 1. Growth of renewable capacity in selected states.

1997, the renewable capacity *decreased*. In California, an RPS was passed in September 2002, mandating that 20% of the state's electricity generation be renewables-based by 2010. Yet the growth thereafter appears to be a simple continuation of the pre-existing trend. In contrast, for the two states that rank as No. 1 and No. 2 based on incremental requirement, New Mexico and Minnesota, passage of an RPS appears to have had a strong and positive impact. New Mexico passed an RPS with gradually increasing requirements (starting in 2005) in December 2002, and shortly thereafter we see the first significant installation of renewable capacity in that state. Similarly, in Minnesota, a series of laws mandating installation of renewable capacity was passed starting in 1994. We see jumps in capacity in 1998, 2001, 2002, and 2006, all years in which the binding requirements increased.

In Section 6, we study the effectiveness of RPS policies employing these and other measures of policy stringency. While Fig. 1 is certainly illustrative, the econometric analysis in the following section includes all states and controls for other policy changes and factors that could also have an impact on our outcome variable.

The dependent variable, *RENEWSHARECAP*, is the share of capacity in a state-year that is based on non-hydro renewable technology. Using EIA-906, we build yearly data files that include all plants that were online in a given year, from 1990 to 2006. We count the capacity of all plants whose primary energy source is classified as non-hydro renewable by EIA. This includes wind, geothermal, and solar-generating units, as well as several types of biomass. We then divide by the total capacity in a state for that year to obtain *RENEWSHARECAP*.

Information on policies other than RPS is retrieved from DSIRE. For social and economic control variables, data on electricity prices,[20] generation,[21] and consumption[22] are obtained from the Energy Information Administration, data on state income is obtained from US census,[23] and data on LCV scores is collected

[20] http://www.eia.doe.gov/cneaf/electricity/epa/epat7p4.html
[21] http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html
[22] www.eia.doe.gov/cneaf/electricity/epa/sales_state.xls
[23] http://www.census.gov/hhes/www/income/4person.html

Table 2
Summary statistics.

Variable	Mean	Standard deviation	Minimum	Maximum
RENEWSHARECAP	2.39	3.71	0	27.36
RPS	0.16	0.37	0	1
RPSTREND	0.70	1.97	0	13
NOMINAL	0.57	3.22	0	30
INCRQMTSHARE	0.07	0.32	0	4.33
MGPOPTION	0.03	0.17	0	1
PUBBENFUND	0.16	0.37	0	1
NETMETERING	0.35	0.48	0	1
INTERCONSTAND	0.17	0.38	0	1
ELECPRICE	7.07	2.16	3.43	18.33
LCVSCORE	44.80	27.21	0	100
STATEINC	57.56	11.46	32.59	94.44
POWERIMPORT	−0.26	0.63	−3.04	0.61
RECFREETRADE	0.05	0.21	0	1
PENALTYACP	0.09	0.29	0	1
NEIGHBOR	0.28	1.72	0	19.59

from the League of Conservation Voters[24]. Summary statistics of the data used in the regression analysis are provided in Table 2.

6. Estimation results

Table 3 presents results from several estimations of Eq. (3), and highlights how the estimates of the effectiveness of an RPS are highly dependent on the coding scheme chosen. When the RPS is introduced into the estimation model as a simple binary variable that is turned on when "treatment" is administered, or as a cumulative count of the years a given state has been subject to this treatment, we obtain coefficients on *RPS* that are not significantly different from 0, as shown in the first two columns of Table 3. This result suggests that RPS policies are ineffective in accelerating renewable energy, which is consistent with Michaels (2007)'s claim that RPS policies are largely symbolic.

In column 3 of Table 3, we instead allow the effect of the RPS policy to be a function of the nominal requirement. As discussed above, this method has two shortcomings, in that it ignores exemptions from the RPS and it includes generation expected from existing capacity that may be eligible under the policy. So if a state introduces an RPS that is already being met, and new non-renewable capacity is erected in the state (causing the renewable share of capacity to drop), we could actually see a *negative* impact. This is in fact what we observe—the coefficient on *NOMINAL* is negative and significant.[25]

However, in column 4 of Table 3, we instead specify that the renewable share of capacity is a function of the "incremental requirement" associated with an RPS policy. As discussed above, this measure is a much more accurate indicator of the strength of an RPS. Under this specification, we get a much more intuitively appealing result—the coefficient on *INCPCTRQMT* is positive and significant. We interpret this coefficient as follows—an RPS that mandates that the utilities serving a state increase the renewable share of generation by 1 percentage point will result, on average, in a 0.56 percentage point increase in the share of capacity that is classified as non-hydro renewable. We adopt these results as our preferred baseline specification.

[24] http://www.lcv.org

[25] This negative result (as well as the comparatively high R^2 measure) is driven by Maine, where the situation described above actually occurred. In 1997, Maine passed an RPS whose nominal requirement (which took effect in 2000) was already easily met by its existing eligible resources. In 2000–2001, Maine brought several new natural gas plants online, while two biomass plants were retired. Estimating the regression in column 3 without Maine results in a coefficient on *NOMINAL* that is statistically indistinguishable from 0. The rest of the results presented in the paper are insensitive to the exclusion of Maine.

Table 3
Measures of RPS and the impacts of RPS on renewable electricity investment.

	(1)	(2)	(3)	(4)
RPS	−0.087			
	(0.431)			
RPSTREND		−0.036		
		(0.182)		
NOMINAL			−0.272	
			(0.044)**	
INCRQMTSHARE				0.558
				(0.175)**
MGPOPTION	3.197	3.254	2.959	2.994
	(0.582)**	(0.719)**	(0.706)**	(0.504)**
PUBBENFUND	−0.467	−0.437	0.115	−0.547
	(0.535)	(0.456)	(0.258)	(0.580)
NETMETERING	−0.713	−0.748	−0.557	−0.652
	(0.438)	(0.562)	(0.219)*	(0.430)
INTERCONSTAND	0.47	0.5	0.344	0.404
	(0.503)	(0.609)	(0.250)	(0.505)
ELECPRICE	−0.097	−0.091	0.138	−0.116
	(0.108)	(0.113)	(0.104)	(0.101)
LCVSCORE	−0.003	−0.003	−0.001	−0.003
	(0.005)	(0.005)	(0.004)	(0.005)
STATEINC	0.01	0.012	0.01	−0.001
	(0.030)	(0.036)	(0.026)	(0.025)
IMPORTRATIO	2.185	2.148	1.376	2.215
	(0.965)*	(0.800)**	(0.392)**	(0.928)**
State fixed effects	Yes	Yes	Yes	Yes
Year fixed effects	Yes	Yes	Yes	Yes
Observations	700	700	700	700
R^2	0.95	0.95	0.97	0.95

Robust standard errors in parenthesis
Fixed effects regressions; in all specifications the dependent variable is the percentage of a state's electricity generating capacity that is based on renewable technology.

* significant at 5%.
** significant at 1%.

In assessing this coefficient, a couple of points bear mentioning. First, because of the intermittent nature of some types of renewable capacity, one might expect that a 1 percentage point increase in generation should actually be associated with a *much greater* increase in capacity. However, a non-trivial portion of the renewable generation produced in a given year is undertaken at facilities that are not classified by EIA as "renewable". These include, for example, natural gas plants that occasionally use landfill gas as a fuel, or coal plants that occasionally use biomass. A de-meaned regression of *Percentage of Renewable Generation* on *Percentage of Renewable Capacity* yields a coefficient of about 0.68, suggesting that if an RPS was the sole force in driving renewable development, was perfectly enforced, and was met with only in-state capacity, we would expect a coefficient of about 1.47.

There are a number of possible explanations for why the coefficient we observe is significantly less than 1.47. The most obvious are (1) that the policies are not being fully enforced, (2) that utilities find it in their interest to comply through the payment of penalties rather than by installing new capacity or acquiring RECs, (3) that most states are complying with the RPS by purchasing out-of-state RECs, or (4) that much of the renewable development we see is being driven either by other policies or by changes in technology that are affecting both RPS and non-RPS states. Unfortunately, our analysis does not allow us to address precisely why the coefficient is less than 1.47.

With regards to other policy variables, it is interesting to note that on average, the mandatory green power option has both an

Table 4
Design of RPS and the impact of RPS on renewable investment.

	(1)	(2)	(3)	(4)	(5)
INCRQMTSHARE	0.492	1.011	0.677	0.557	0.931
	(0.219)*	(0.307)**	(0.155)**	(0.188)**	(0.251)**
MGPOPTION	2.983	2.896	2.876	2.994	2.685
	(0.504)**	(0.481)**	(0.531)**	(0.518)**	(0.463)**
PUBBENFUND	−0.525	−0.566	−0.34	−0.547	−0.242
	(0.594)	(0.608)	(0.476)	(0.609)	(0.452)
NETMETERING	−0.664	−0.625	−0.612	−0.651	−0.693
	(0.425)	(0.459)	(0.397)	(0.437)	(0.426)
INTERCONSTAND	0.422	0.36	0.366	0.404	0.447
	(0.499)	(0.554)	(0.467)	(0.504)	(0.511)
ELECPRICE	−0.113	−0.131	−0.085	−0.116	−0.06
	(0.101)	(0.101)	(0.102)	(0.102)	(0.116)
LCVSCORE	−0.003	−0.002	−0.002	−0.003	−0.002
	(0.005)	(0.005)	(0.004)	(0.005)	(0.004)
STATEINC	0.002	−0.003	0.013	−0.001	0.016
	(0.024)	(0.023)	(0.031)	(0.023)	(0.026)
IMPORTRATIO	2.206	2.201	2.238	2.216	2.145
	(0.936)*	(0.901)*	(0.975)*	(0.911)*	(0.888)*
IMPORTRATIO × *INCRQMTSHARE*	−0.318				−1.339
	(0.312)				(0.503)*
RECFREETRADE		0.301			1.678
		(0.442)			(1.111)
RECFREETRADE × *INCRQMTSHARE*		−0.71			−1.529
		(0.357)+			(0.503)**
PENALTYACP			−0.937		−1.744
			(0.729)		(1.177)
PENALTYACP × *INCRQMTSHARE*			−0.026		0.773
			(0.650)		(0.736)
NEIGHBOR				−0.001	−0.331
				(0.038)	(3.828)
Year fixed effects	Yes	Yes	Yes	Yes	Yes
Observations	700	700	700	700	700
R^2	0.95	0.95	0.95	0.95	0.95
Wald test *p*-value		0.11	0.12		0.04

Robust standard errors in parenthesis. Fixed effects regressions; in all specifications the dependent variable is the percentage of a state's electricity generating capacity that is based on renewable technology. The Wald test *p*-value row gives the *p*-values on a test that the coefficients on the variables not included in the baseline specification (Table 3, Column 4) are jointly equal to 0.

+ significant at 10%.
* significant at 5%.
** significant at 1%.

immediate and persistent impact on the renewable share of capacity in a state. The coefficient for *MGPOPTION* is positive and significant regardless of how *RPS* is measured. A more surprising set of results is the negative and occasionally significant coefficients on the variables associated with both the public benefits fund and the net-metering policy alternatives. The only non-policy variable that has a significant coefficient is *IMPORTRATIO*, a finding which suggests that states that experience an increase in the import of electricity have acted more aggressively in developing renewable energy in subsequent years.

In column 1 of Table 4, we add the interaction term between *IMPORTRATIO* and *INCRQMTSHARE* to our baseline specification, and obtain a coefficient that is not statistically different from 0. This suggests that RPS policy success, as defined for the purpose of this paper, does not depend on the size of a state's electricity supply, relative to its demand.

The impact of two RPS design features are examined in columns 2 and 3 of Table 4. In column 2, we investigate the effect of how an RPS policy treats out-of-state RECs. We introduce *RECFREETRADE* and its associated interaction term into our baseline specification. As one might expect, allowing out-of-state REC's mitigates the effectiveness of the RPS significantly. The results suggest that a mandated increase of 1 percentage point of the renewable share of generation will result, on average, in a 1.01 percentage point increase in states that either prohibit or otherwise discourage out-of-state RECs, and in a 0.30 percentage point increase in states that place no restrictions on out-of-state REC's. A Wald test of this latter effect reveals that the resulting impact is no longer significantly different from 0.[26]

In column 3, we investigate whether an RPS policy is rendered more or less effective by the existence of a penalty or ACP. We introduce *PENALTYACP* and its interaction term with *INCRQMTSHARE* into our baseline specification. Both *PENALTYACP* and its associated interaction term have a coefficient that is not statistically different from 0. A Wald test of the joint significance of coefficients for *PENALTYACP* and *PENALTYACP* × *INCRQMTSHARE* yields a *p*-value of 0.12, slightly above conventional thresholds for statistical significance.

Column 4 of Table 4 introduces *NEIGHBOR* into the baseline specification; the estimated coefficient is small and essentially no different from zero. This suggests that the growth of renewable capacity in a state cannot be explained by increases in the relative size of the renewable electricity market resulting from RPS implementation in neighboring states.

Column 5 of Table 4 presents the results from a specification that includes all variables used in the previous specifications of Table 4. The key insights are unchanged, with the exception that the coefficient on the interaction between *IMPORTRATIO* and *INCRQMTSHARE* is now significant. This suggests that compared to states that are more energy self-sufficient, the impact of RPS

[26] This interpretation assumes that a stat RPS is already in place and is not altering its treatment of out-of-state RE.

policies is smaller in states that rely on imported electricity. This finding is consistent with the idea that RPS policy outcomes are dependent on the transmission infrastructure that exists in a state at the time the RPS takes effect—states with a higher *IMPORTRATIO* will, more often than not, also have in-state transmission grids that are constrained, meaning that the addition of new in-state renewable resources will be more difficult.[27] It is also interesting to note that the baseline effect of *INCRQMT* is now 0.93, notably closer to the coefficient of 1.47 that we would expect if the RPS were perfectly enforced, met with only in-state capacity, and perfectly binding.

Our analysis in this article treats all policies as exogenous, which is clearly a very strong assumption that is unlikely to hold in practice. We acknowledge that endogeneity is a valid concern. Accordingly, our analysis has included social and economic variables thought to impact RPS adoption. However, we recognize that this does not fully address endogeneity concerns. Work in progress by the authors more thoroughly addresses issues of endogeneity and also investigates whether RPS policies to date have led to an increase in electricity prices.

7. Conclusion

Existing empirical research on the impact of state-level RPS policies in the United States has often taken a naive approach. This has usually included a cross-sectional approach or the use of very blunt proxies for policies that are in fact very heterogeneous.

In this paper, we have introduced a new way to measure the stringency of renewable portfolio standards (RPS). We argue that it is a much better indicator of the magnitude of the incentive provided by an RPS because it explicitly accounts for some RPS design features that may have a significant impact on the strength of an RPS. The difference between this new measure and other more commonly used measures is striking; some seemingly aggressive RPS policies in fact provide only weak incentives, while some seemingly moderate RPS policies are in fact relatively ambitious.

We also investigate the impacts of renewable portfolio standards on the renewable electricity development in a state using our new measure of RPS stringency, and compare the results with those when alternative measures are used. The difference in the estimates is again striking. Using our new measure, we confirm that, on average, RPS policies have had a significant and positive effect on in-state renewable energy development. These results cast doubt on the argument that the passage of RPS policies has been purely symbolic, or that they have otherwise not been implemented. These findings are masked when differences among RPS policies are ignored. We also find evidence that another important design feature – allowing "free trade" of REC's – can significantly weaken the impact of an RPS, and that the effectiveness of an RPS is in part dependent on a state's existing 'balance of trade' in electricity. It should come as no surprise that the importance of digging into policy design details is crucial when assessing policy effectiveness. These results should prove instructive to policy makers, whether considering the development of a federal-level RPS or the development or redesign of a state-level RPS.

Acknowledgments

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[27] Vajjhala et al. (2008) explores the interdependence between transmission and renewable policy success with a series of simulations.

Vest, Lisa A. (DNREC)

From:	Lisa Locke <lisavlocke@gmail.com>
Sent:	Tuesday, February 10, 2015 10:03 AM
To:	Vest, Lisa A. (DNREC)
Cc:	Noyes, Thomas G. (DNREC); John Sykes
Subject:	Regulation 102 testimony
Attachments:	RPS Rule - DeIPL.docx; ATT00001.htm

Dear Ms. Vest,

Please find attached a letter of testimony in support of proposed Regulation 102 for DNREC's implementation of the Renewable Portfolio Standards (RPS) and cost cap provisions.

Please let me know if you have any questions. We would welcome any opportunity to further offer our support to ensure a robust and continuing RPS for the State of Delaware.

Respectfully,

Lisa Locke

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Delaware Interfaith Power & Light, Inc.
A Religious Response to Climate Change
www.DelPL.org

February 10, 2015

Lisa Vest
Public Hearing Officer
State of Delaware -DNREC
89 Kings Highway
Dover, DE 19901

Dear Ms. Vest,

This testimony is in support of proposed Regulation 102 for DNREC's implementation of the Renewable Portfolio Standards (RPS) and cost cap provisions. We believe that the legislation and the law in this case clearly provide some discretion on the part of the Director in deciding when and whether a freeze **may** be instituted on the implementation of the RPS schedule.

BACKGROUND

Delaware Interfaith Power & Light is one of 40 state affiliates of the national Interfaith Power & Light (IPL), initiated in California in 1998. DeIPL was founded in 2011, currently has 24 member congregations throughout Delaware and is growing steadily. Our mission is to provide a religious response to climate change through promotion of energy conservation, energy efficiency, renewable energy and environmental justice strategies.

We consider our work – whether sharing scriptures, hosting workshops, distributing eco-kits, expanding green space, coordinating solar energy projects, creating partnerships or meeting with legislators - a moral imperative. Our goal, ultimately, is to assure the preservation of a healthy, sustainable planet; but, closer to home, to improve the everyday quality of life of our families, our neighbors and our communities.

RATIONALE

Opponents of the proposed rule would suggest that the decision to suspend the RPS schedule should be based solely on the value of the retail price of electricity. If this were the case and what the legislature had in mind, consultation with the public service commission would not have been included and the word "**shall**" would have purposely been used rather than the word "**may**".

DeIPL also would note that any calculation of price must, by statute, follow the definition of "Compliance Year", as defined in 75 Del. Laws, c. 205, § 1, § 352 Definitions as, "'Compliance Year' means the calendar year beginning with June 1 and ending with May 31 of the following year..."

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Moreover, PSC staff have submitted testimony that the consideration of external benefits should be consistent with the Commission-regulated electric company's IRP. In Delmarva Power & Light's IRP of December of 2012, it is stated that "*Most of the available literature on environmental externality points to global warming and the human health effects of air emissions as dominating energy externalities. This was a primary consideration in shaping the process used by Delmarva to quantify environmental benefits and impacts.*" Indeed, Section 351 of Chapter 1 of Title 26 of Delaware code *specifies improved regional and local air quality* and *improved public health* as the first to two benefits of RPS. In fact, Delaware continues to fail the standards of the American lung association regarding the high ozone days with **a grade of "F"** for all three counties. And, as the burning of fossil fuels is highly contributory to global warming, climate change and sea level rise, the risk to Delawareans continues to increase. Last year had the highest global average temperature in history, and coastal storms and sea level rise are expected to cause increasing damage to Delaware's natural and human resources.

Another benefit called out by Title 26 is *new economic development opportunities.* Delaware now ranks 7th nationwide in new per capita solar installations and could further expand its rate of installations and the jobs that would bring. As with any business, Delaware's solar industry must be able to rely on the continuity of the RFP's schedule and not the impersonal result of a spreadsheet. In view of Delaware's special vulnerability to sea level rise and coastal storms, and the rapid decline in the cost of solar PV, we would like to see the solar schedules for solar PV and other Eligible Energy Resources (especially offshore wind) accelerated rather than slowed.

A growing and consistent RPS schedule is critical for decreasing air pollution, growing a healthy economic blue-collar base, increasing electric supply diversity and realizing electricity price stability. The legislation was written to take these factors into consideration, while enabling the Director to make an informed decision when considering enacting an RPS schedule freeze. DeIPL strongly supports Regulation 102.

Respectfully,

Lisa Locke

Lisa Locke, Executive Director
Delaware Interfaith Power & Light

John D. Sykes

John Sykes, President
Delaware Interfaith Power & Light

Vest, Lisa A. (DNREC)

From:	Michael.Messer@linde.com
Sent:	Tuesday, February 10, 2015 1:51 PM
To:	Vest, Lisa A. (DNREC)
Cc:	Michael.Messer@linde.com
Subject:	Linde LLC Comments Submittal For DNREC 102 NOPR
Attachments:	Linde DNREC 102 Comments Final.doc

Ms. Vest,

Attached are comments submitted by Linde LLC for the DNREC 102 Implementation of Renewable Portfolio Standards Cost Cap Provisions NOPR.

Please accept the comments and incorporate them into the official comment period for this NOPR.

Please confirm that the comments were received.

Thank You.

Respectfully Submitted,

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THE LINDE GROUP

Linde

Linde LLC

Delaware Department of Natural Resources and Environmental Controls (DNREC)

Comments on DNREC 102 Implementation of Renewable Portfolio Standards Cost Cap Provisions NOPR

Delaware Register 12/1/14

February 10, 2015

TABLE OF CONTENTS

SUMMARY

The following statements and comments of Linde LLC ("Linde") are in reference to the Department of Natural Resources and Environmental Control's (DNREC) Proposed Regulations re: 102 Implementation of Renewable Portfolio Standards Cost Cap Provisions NOPR printed in the Delaware Register 12/1/14 ("Proposal").

Linde requests DNREC to implement the following actions:

- Freeze the Delaware Renewable Portfolio Standards (RPS) Program as required by Title 26 Section §354 items (i) & (j) for a 3% cost cap violation effective immediately.
- Implement modifications to the RPS Program such that future compliance costs are reduced and do not exceed the 3% cost cap (1% solar cap) limits of Section §354 (i) and (j).
- Develop and implement an initiative to apply the RPS Program compliance cost overpayments above the 3% cost cap for the 2013 and 2014 compliance years as a credit against future costs effective immediately until a "net" cumulative 3% expenditure level is realized and then continue the RPS Program per Section §354 cost cap limits.
- Modify the proposed rules contained in the NOPR Proposal to reflect:
    - Implementation of absolute RPS Program freeze levels and cost control limits at a 3% level (1% solar) of retail electric supplier total costs.
    - Elimination of discretionary evaluations to modify or soften enforcement of the 3% cost limit (1% solar).
    - Reduction in the proposed 150 – 180 day evaluation time to determine the cost of RPS Program Compliance. Large energy intensive businesses can provide data on compliance costs in real time to facilitate enforcement of cost cap controls.
    - Removal of language to exclude existing contracts from compliance with the 3% (1% solar) cost cap controls of Section §354.

During Senate June 22nd 2010 and House of Representatives June 29th 2010 floor proceedings for Senate Substitute No. 1 for Senate Bill No. 119 (SS1), commitments were made to ensure ratepayers received price protections where none currently existed and to ensure there would be no adverse ratepayer cost impacts from the legislation to expand requirements of the State's RPS Program. Numerous references were made to "Circuit Breaker" or absolute ratepayer protection in both proceedings and were codified as items (i) and (j) in Section §354.

The RPS Program actions requested by Linde above are consistent with the commitment made to the Delaware Legislation.

RPS Program cost control actions per the 3% cost cap should have already been implemented prior to this Proposal. Linde has experienced a cost impact (Qualified Fuel Cell Provider, QFCP surcharge) of almost 6% for the 2013 Compliance Year with these costs increasing to almost 9% in the 2014 Compliance Year. An energy intensive business will have a QFCP cost impact that approaches or exceeds $1 million per year. Extrapolating that cost over the twenty-year QFCP Project life leads to a cost approaching $18 million. These cost figures do <u>not</u> include the RPS rate surcharge component.

The Delmarva Power 2014 Integrated Resource Plan (IRP) illustrates the long-term impact of current RPS Program expenditures. Delaware citizens and businesses are projected to be exposed to Renewable Energy Certificate (REC) costs that are <u>approaching $400 to $500 million above actual market costs over the project life</u> (QFCP surcharge only). Delmarva Power also projects Residential Customer costs of over $8.00/month in the 2015 Compliance Year at a rate that is at least double the Section §354 3% cap limit and substantially higher than statements made to the Delaware Legislation on June 29, 2010.

Linde will also document that the present level of RPS Program cost (QFCP surcharge) is at least four times higher than respective RPS Program costs experienced at other states where Linde operates manufacturing facilities.

The commitments made to the Delaware Senate and House of Representatives in June 2010 for ratepayer price protection have not been enforced and would not be enforced under the DNREC Proposed Rule Making. Linde is fully supportive of the Delaware RPS Program as enacted under Section §354 following the price protections included therein. Our company is an active market participant in and supports various Clean Energy technologies, including the fuel cell industry.

Linde's comments throughout this document will refer to the QFCP surcharge component of the Retail Provider Compliance Rate (RPCR). We will not discuss in great detail the RPS surcharge component of the RPCR rate that pushes RPS Program compliance costs even higher. Present RPS Program costs will have a negative impact on the competitiveness of Linde vs. our competitors in Maryland and Pennsylvania who do not incur these costs and result in near-term shifting of production to Linde's plants in Pennsylvania. The long-term business viability of our Claymont, Delaware facility will be a concern.

Linde seeks immediate action to Freeze the RPS Program, correct RPS Program overpayments down to the 1% and 3% cap limits and application of overpayments in 2013 and 2014 Compliance year toward future commitments as committed to the Delaware Legislation.

LEGISLATIVE BACKGROUND

Floor proceedings for SS1 from 6/22/10 and 6/29/10 in the Senate and House of Representatives respectively contain eleven references[1] to "Circuit Breaker" ratepayer price protections. These references were committed to the Legislature as absolute price protections should RPS Program costs exceed 1% for solar or 3% in total of retail electricity supplier costs. If and when RPS Program cost got to this level, the rate payers could be protected. There was no reference to discretionary evaluations to support costs exceeding the caps. The purpose of "Circuit Breaker" cost caps was to eliminate adverse impacts via a definitive action to Freeze the RPS Program.

DNREC Secretary (in June 2010) O'Mara made the following statement during the 6/29/10 House of Representative proceedings:

> "But most importantly, by having a circuit breaker, if you will, an actual price control, whereby if the, if the ratepayer impacts exceed a certain amount, that the entire program freezes in place, we can ensure ratepayers that there won't be any adverse impacts from this legislation."[2]

Secretary O'Mara continued to state the creation of absolute price protections by highlighting (in reference to a Solar question):

> "You'll never have more than a 1% impact in any given year for the solar."[3]

Finally, Secretary O'Mara stated that California ratepayers saw adverse impacts from their RPS Program but that Delaware would not see the adverse cost impacts experienced in California because:

> "They did not put the consumer protections in place that we're talking about, so there have been adverse impacts there because they did not take that step."[4]

The intent to eliminate adverse impacts is clear throughout the 6/29/10 proceeding by enacting an absolute price cap of 1% for solar and 3% REC cap overall. <u>A California equivalent impact is being experienced currently in Delaware as Section §354 cap limits have not been enforced and will continue to exist unless the DNREC rulemaking follows the commitment made to the Legislature.</u>

In the Senate 6/22/10 floor proceedings, the same commitment to absolute or "Circuit Breaker" ratepayer price protections was made.

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[1] SS1 HD at 5,9,27,33,34 (McDowell) and SS1HD at 6-7 (O'Mara).
[2] SS1 HD at 6 – 7 (O'Mara)
[3] SS1 HD at 13 (O'Mara)
[4] SS1 HD at 18 (O'Mara)

Senator McDowell committed the intent of a serious and firm or absolute cost cap limit as follows:

> "We've also built safety valves into this bill. .... the retail electric would go up by 1 percent in a year in the case of solar, or 3% in the overall, they could push the circuit breaker, ...And so that is very, very serious rate production -- ratepayer protection."[5]

The Delaware Legislation received firm commitments that ratepayer protection from adverse impacts would be implemented under this bill. This protection has not been enforced and energy intensive consumers can experience multi-year exposure to approximately $1 million in RPS Program surcharges for the QFCP surcharge rate alone.

Delaware citizens and businesses are due the immediate freeze of the RPS Program, an action plan to limit future costs to a 3% cap limit of retail supplier electricity costs and a credit of over payments in the 2013 and 2014 Compliance Years against future payments until the credit is exhausted.

LINDE INTRODUCTION

Linde is a member of the Linde Group, the largest global gases and engineering company with world wide revenue of $16.665 billion (EUR) and approximately 63,500 employees.

In Delaware, Linde operates an industrial atmospheric gases manufacturing facility in Claymont that has been in business for over forty years. This facility utilizes a significant amount of electricity to separate air into its main components, oxygen, nitrogen and argon. Claymont operates on Delmarva Power's GS-T rate (transmission voltage service).

The atmospheric gases business is extremely cost sensitive and must take costs into consideration in determining the pricing of its product. The highest cost component of our manufacturing process, at 60% of total cost, is the cost of electricity. Therefore, Linde must pursue initiatives to try and minimize its power costs. However, the value of all such initiatives at the Claymont facility is now essentially offset by the RPS Program costs.

Without a defined cap on the QFCP surcharge cost, Linde faces unpredictability on its production costs at Claymont. A substantial surcharge in any given year

[5] SS1 HD at 9 (McDowell)

can easily put Linde at a competitive disadvantage with its competitors who have facilities in Maryland and Pennsylvania.

LINDE ELECTRIC COST SENSITIVITY

Electric supply related costs are a critical operational issue for Linde's business. Linde undertakes numerous company-wide non-core business initiatives to pursue cost reduction opportunities and improve Linde's competitive position. For example, Linde created a wholly owned subsidiary, Linde Energy Services, Inc. (LESI) to serve as the electric supplier to Linde's facilities, including the Claymont facility.

Linde's efforts at Claymont are being offset by the QFCP surcharge impact of approximately a $1 million per year.

Linde has initiated the following initiatives at the Claymont facility to reduce our electric supply costs:

- Operate the Claymont facility to consume electricity at a consistent level during the day with no substantial load variations between day-time and night time hours. This creates a load factor or energy consumption rate of 90% or higher (also known as a "Flat load curve"). Generation owners prefer this flat load curve to enhance their plant efficiencies during lower night time loads.

- Participate in the PJM Reliability Pricing Model (RPM) Program to improve the reliability of the bulk electric system during system emergency conditions. Claymont has consistently met all of its load reduction requirements to PJM over the past ten-year period and provided load reduction benefits during the most recent 2014 Polar Vortex weather conditions. In exchange for load reductions at Claymont, Linde receives payments that vary but are approximately $500,000 per year. Although Linde suffers lost production with a load reduction, the revenues received sufficiently outweigh the lost production.

- Participate in the PJM Synchronized Reserve (SR) Program (first end-use load to participate in the PJM Market) to improve PJM system reliability. The value to Linde is approximately $100,000 per year.

- Manage electric supply at the PJM market node versus the load zone. Linde reduced supply costs to match the actual cost to serve the location (first load in PJM market to implement nodal supply).

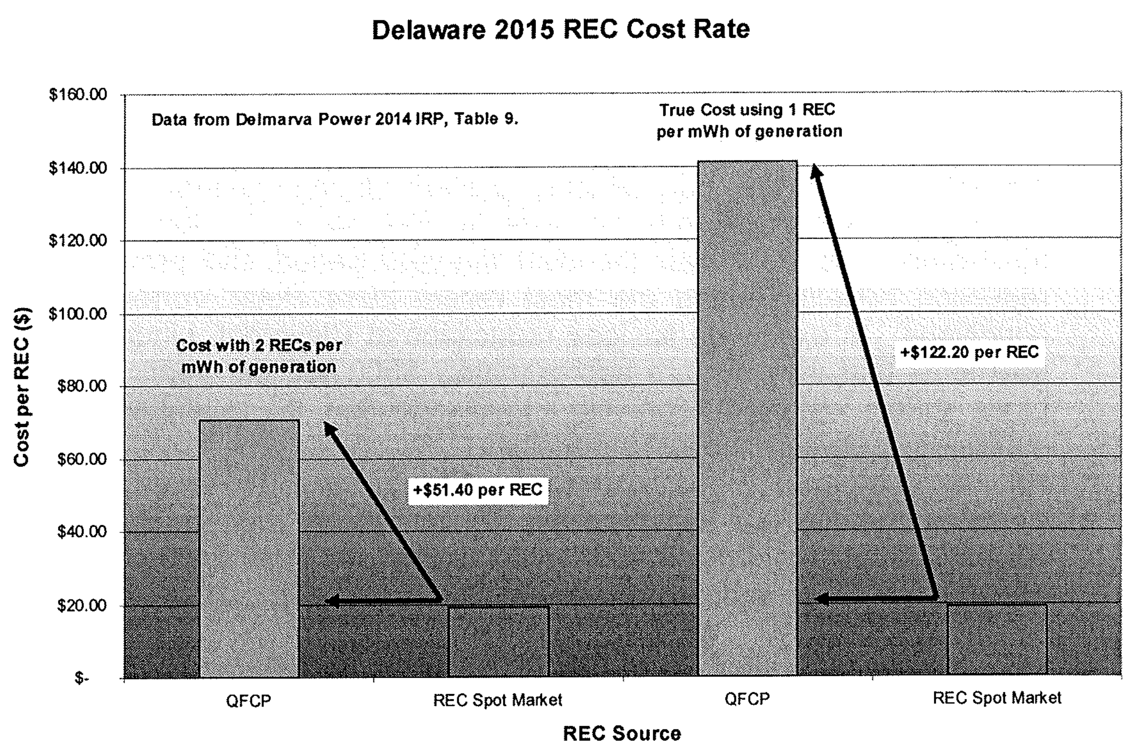
The value of the above initiatives to the Claymont facility is now effectively eliminated by the excessive QFCP surcharge.

QFCP SURCHARGE COST EVALUATION

Linde payments to the RPS Program are reflected by the QFCP rate. As stated earlier, surcharges are ~6% of electric costs for the 2013 Compliance year and approaching 9% for the 2014 Compliance Year.

Chart 1 below highlights why the QFGCP surcharges are above the 3% RPS Program cap limit. The two bars on the left side of the chart compare the current Spot Market costs for RECs (non-Solar and non Wind-Contract) compared to the cost of the QFCP Project for 2015. QFCP costs per REC are $70.70/REC and 3.7 times greater than the spot market price of $19.30 per REC. Stated differently, Delmarva Power could buy the QFCP generated RECs in the Spot Market for $51.40 less per REC. Costs for this analysis come directly from the Delmarva Power 2014 IRP Plan, Table 9. Operation of the QFCP project has a dramatic and adverse cost impact on Delaware citizens and businesses.

CHART 1: COMPARISON OF QFCP REC COST TO SPOT MARKET COST



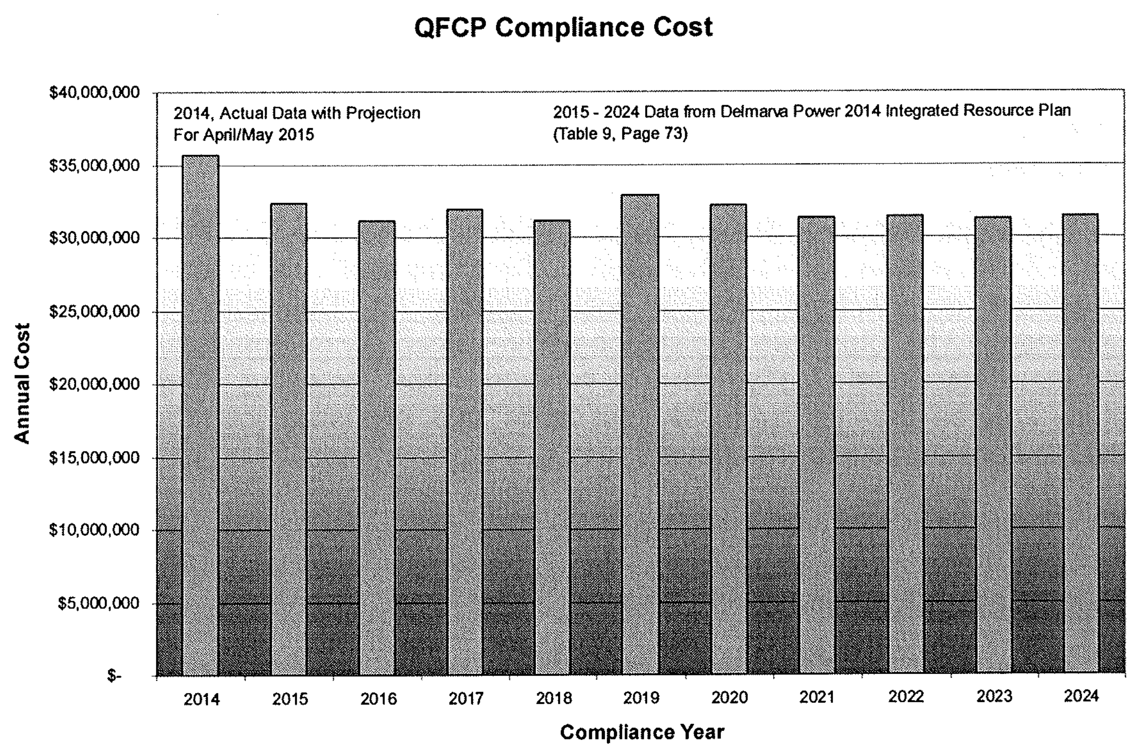
The cost of $70.70 is artificially created by the administrative QFCP project allowance to collect two RECs for every mWh of generation versus other market participants receiving one REC per mWh of generation. Therefore, the true cost of the QFCP RECs is $141.40 per REC if not for the administrative privilege (See Chart 1, bars on the right side of the chart). This would put the QFCP REC cost at $122.20 above the Spot Market.

Delaware is paying an unprecedented premium to acquire RECs to meet the RPS Program requirements. The analysis confirms that the 3% cap limit needs to be enforced on the RPS Program.

LONG-TERM IMPACT OF THE QFCP SURCHARGE

A long-term projection of QFCP surcharges in included in the Delmarva Power 2014 IRP Plan, see Table 9. The information is presented graphically in Chart 2 below.

CHART 2: DELMARVA PROJECTION OF QFCP COSTS



From 2014 through 2024, all eleven years show a cost greater than $30 million per year. The cost comes from the Delmarva monthly calculation of payments due to the QFCP Project via tariff. These amounts represent costs above the market cost for electric power. All eleven years add up to a $352.5 million plus the project has another five years at a rate that is approximately 60% of the above rate ($102/mWh of generation vs. current rate of $166.87/mWh).

Therefore, the project life cost impact as projected by Delmarva Power and its consultants is approaching or over $400 million. Costs that are above the electric supply market projected costs.

Linde submits that the QFCP surcharge rate, both current and future forecasts are far beyond the commitments made to protect ratepayers and represent adverse impacts for the State. Action is required to freeze the RPS Program before adverse cost impacts increase any further and initiate corrective action to return costs to a 3% of electric supply costs. Note: 2014 cost is projected based on current compliance year payments.

LINDE PROJECTION OF LONG-TERM QFCP SURCHARGE COSTS

Linde offers our projection of QFCP surcharge costs over the life of the project in Table 1. Our cost projections are for the QFCP surcharge to accumulate to a level of approximately $500 million over the project life. This projected premium payment for electric supply and RECs is supportive of immediate mitigation actions as described by Linde to meet the commitment made to the Delaware Legislation.

The Linde and Delmarva Power life cost projections for the QFCP Project range from ~$400 million to ~$500 million. Cost impacts are different but both projections demonstrate severe cost impacts for Delaware citizens and businesses. The Delaware Legislation had received commitments and an action plan that these level of adverse cost impacts would not occur. Delaware must act to enforce the 1% and 3% cost limits and eliminate the unprecedented adverse cost impacts for ratepayers.

Table 1 Calculation Inputs:

Two key factors (energy and capacity) determine the cost of electric supply for large consumers.

> First is the DPL North Zone energy price. This price is known at the PJM West Hub location with great certainty via the NYMEX and ICE forward markets. Table 2 includes the forward electric prices from these markets at the 1/16/15 market close (2015 through 2020). These prices represent actual purchases and sales between market participants at the time of the

market close. The prices are not projections. Starting in 2021, the PJM West Hub Price is escalated 3% per year to represent market cost increases during the life of the QFCP Project.

TABLE 2: PJM WEST HUB PRICE (NYMEX & ICE) FORWARD PRICES

2015	$36.86/mWh
2016	$37.52/mWh
2017	$37.29/mWh
2018	$37.25/mWh
2019	$37.36/mWh
2020	$37.66/mWh

The PJM West Hub price must be modified to reflect the transmission system congestion costs that exist between the West Hub and DPL North Zone. Table 3 presents actual congestion costs for 2010 through 2014. The highest cost was $2.27/mWh with some years showing that DPL North prices were less than West Hub. To create a conservative forecast (one that benefits the QFCP project) we used a $4.00/mWh congestion cost to give a higher DPL Zone price.

Table 3: Congestion Between DLP North and PJM West Hub Day-Ahead Price

Year	DPL North Price	PJM West Hub Price	Congestion
2014	$52.60/mWh	$51.02/mWh	$1.58/mWh
2013	$37.80/mWh	$38.42/mWh	-$0.62/mWh
2012	$33.46/mWh	$33.90/mWh	-$0.44/mWh
2011	$46.22/mWh	$43.95/mWh	$2.27/mWh
2010	$48.86/mWh	$46.59/mWh	$2.27/mWh

Second, Capacity costs are the next most significant factor affecting future retail electric supply costs. Table 1 uses actual RPM Market auctions from today through 5/31/18. Starting 6/1/18, prices were assumed to move from the current level upward to the value of Net Cone in the PJM Marketplace or $350/MW-Day. This assumption was made as a conservative one that benefits the QFCP Project and recognizes the potential proposed cost of PJM's Capacity Performance Market redesign.

Finally, REC cost credits for the QFCP surcharge are taken from the Delmarva Power 2014 IRP plan through 2024 and then escalated at 5%.

TABLE 1: LINDE PROJECTION OF QFCP SURCHARES OVER PROJECT LIFE

Project Year	Calendar	Bloom Fuel Cell Output mWh	Bloom Electric Price ($/mWh)	Bloom Gas Price ($/mWh)	Total Bloom Pymt. From Customers ($)	PJM West Hub Price ($/mWh)	Congestion DPLN to West Hub ($/mW)	PJM DPL North Price ($/mWh)	PJM Capacity Price (MW-Day)	Bloom Energy Revenue ($)	Bloom Capacity Revenue ($)	Bloom REC SREC Revenue	Bloom Project Net Customer Cost
1	2014	226008	$ 166.87	$ 32.05	$ 44,957,511			$ 52.60		$ 11,888,021	$ 222,600	$1,356,048	$ 31,490,843
2	2015	226008	$ 166.87	$ 32.69	$ 45,102,382	$ 36.86	$ 4.00	$ 40.86	$ 167.46	$ 9,234,687	$ 1,742,003	$1,744,557	$ 32,381,136
3	2016	226008	$ 166.87	$ 33.34	$ 45,250,151	$ 37.52	$ 4.00	$ 41.52	$ 119.13	$ 9,383,852	$ 1,252,295	$2,190,501	$ 32,423,503
4	2017	226008	$ 166.87	$ 34.01	$ 45,400,875	$ 37.29	$ 4.00	$ 41.29	$ 120.00	$ 9,331,870	$ 1,287,720	$2,629,310	$ 32,151,974
5	2018	226008	$ 166.87	$ 34.69	$ 45,554,613	$ 37.25	$ 4.00	$ 41.25	$ 190.00	$ 9,322,830	$ 2,045,825	$2,929,402	$ 31,256,557
6	2019	226008	$ 166.87	$ 35.39	$ 45,711,427	$ 37.36	$ 4.00	$ 41.36	$ 240.00	$ 9,347,691	$ 2,584,200	$3,140,815	$ 30,638,721
7	2020	226008	$ 166.87	$ 36.09	$ 45,871,376	$ 37.66	$ 4.00	$ 41.66	$ 350.00	$ 9,415,493	$ 3,768,625	$3,298,865	$ 29,388,393
8	2021	226008	$ 166.87	$ 36.82	$ 46,034,524	$ 38.79	$ 4.12	$ 42.91	$ 350.00	$ 9,697,958	$ 3,768,625	$3,464,269	$ 29,103,672
9	2022	226008	$ 166.87	$ 37.55	$ 46,200,936	$ 39.95	$ 4.24	$ 44.20	$ 350.00	$ 9,988,897	$ 3,768,625	$3,351,141	$ 29,092,273
10	2023	226008	$ 166.87	$ 38.30	$ 46,370,675	$ 41.15	$ 4.37	$ 45.52	$ 350.00	$ 10,288,564	$ 3,768,625	$3,178,400	$ 29,135,087
11	2024	226008	$ 166.87	$ 39.07	$ 46,543,810	$ 42.39	$ 4.50	$ 46.89	$ 350.00	$ 10,597,221	$ 3,768,625	$2,715,511	$ 29,462,453
12	2025	226008	$ 166.87	$ 39.85	$ 46,720,407	$ 43.66	$ 4.64	$ 48.30	$ 350.00	$ 10,915,137	$ 3,768,625	$2,851,287	$ 29,185,358
13	2026	226008	$ 166.87	$ 40.65	$ 46,900,536	$ 44.97	$ 4.78	$ 49.74	$ 350.00	$ 11,242,591	$ 3,768,625	$2,993,851	$ 28,895,468
14	2027	226008	$ 166.87	$ 41.46	$ 47,084,268	$ 46.32	$ 4.92	$ 51.24	$ 350.00	$ 11,579,869	$ 3,768,625	$3,143,544	$ 28,592,230
15	2028	226008	$ 166.87	$ 42.29	$ 47,271,674	$ 47.71	$ 5.07	$ 52.77	$ 350.00	$ 11,927,265	$ 3,768,625	$3,300,721	$ 28,275,063
16	2029	226008	$ 102.00	$ 43.14	$ 32,801,689	$ 49.14	$ 5.22	$ 54.36	$ 350.00	$ 12,285,083	$ 3,768,625	$3,465,757	$ 13,282,224
17	2030	226008	$ 102.00	$ 44.00	$ 32,996,667	$ 50.61	$ 5.38	$ 55.99	$ 350.00	$ 12,653,636	$ 3,768,625	$3,639,045	$ 12,935,361
18	2031	226008	$ 102.00	$ 44.88	$ 33,195,544	$ 52.13	$ 5.54	$ 57.67	$ 350.00	$ 13,033,245	$ 3,768,625	$3,820,997	$ 12,572,677
19	2032	226008	$ 102.00	$ 45.78	$ 33,398,398	$ 53.69	$ 5.70	$ 59.40	$ 350.00	$ 13,424,242	$ 3,768,625	$4,012,047	$ 12,193,484
20	2033	226008	$ 102.00	$ 46.69	$ 33,605,310	$ 55.30	$ 5.87	$ 61.18	$ 350.00	$ 13,826,969	$ 3,768,625	$4,212,649	$ 11,797,066
					$856,972,773					$ 219,385,121	$61,895,392		$514,253,541

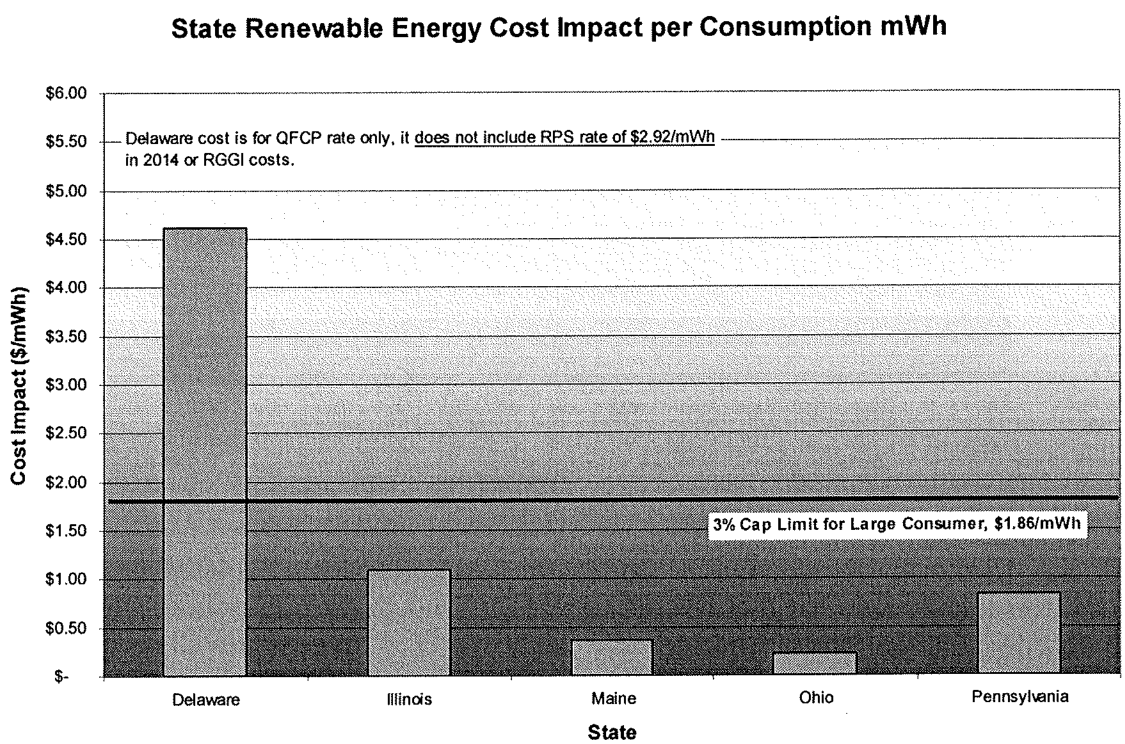
DELAWARE RPS PROGRAM COST VS. OTHER STATES

Linde conducts manufacturing operations in four additional states across the Northeast and Midwest U.S. with RPS Programs. Those states include Illinois, Maine, Ohio and Maine.

Chart 3 presents the RPS Program cost per mWh of Linde plant consumption in each State for 2014. The chart clearly shows that Delaware RPS Program costs are four times greater than the next highest cost State of Illinois.

The comparison again highlights that there are severe adverse cost impacts for an energy intensive customer who has to compete against other companies in these states or who could shift manufacturing to these alternate sites.

CHART 3: DELAWARE RPS COST COMAPRISON TO OTHER STATES

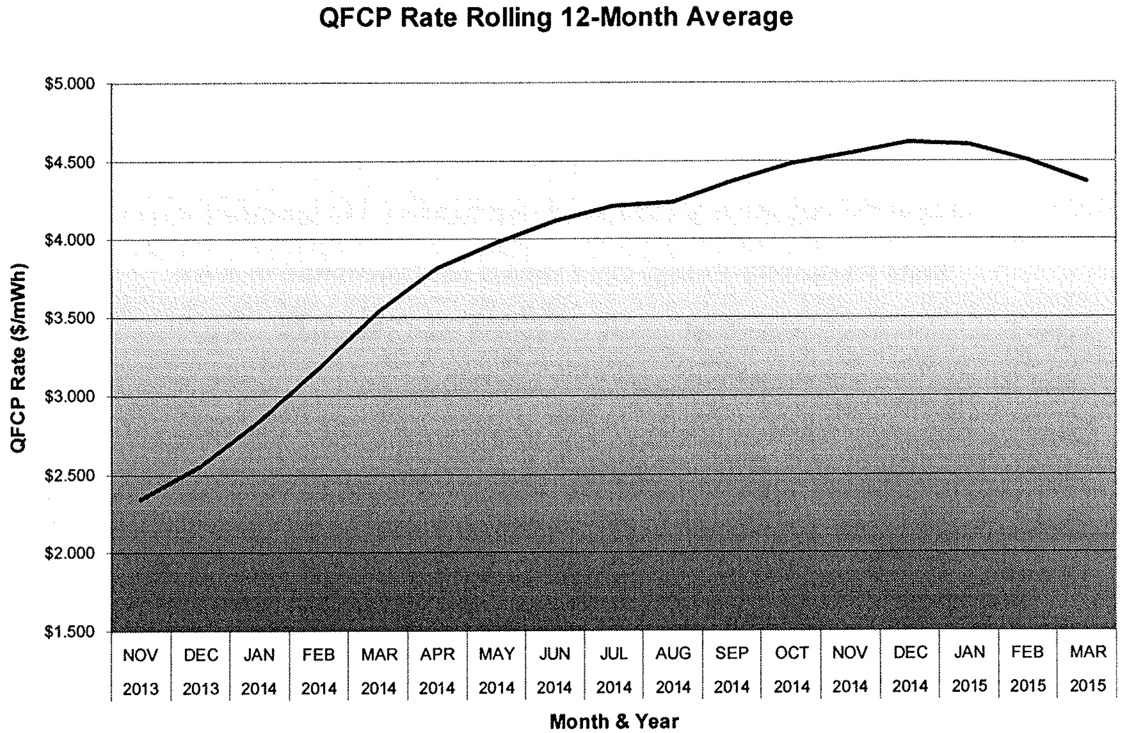


We updated the Chart 3 cost comparison to present Delaware RPS charges at the 3% cap limit level. The red line on Chart 3 represents the 3% cap limit. At this level, the chart shows that Delaware RPS Program costs are still two times higher than the next highest state. <u>A 3% cap limit could still be argued as an adverse cost impact but Linde believes that competitive operations can be performed at the 3% cap limit level.</u>

QFCP SURCHARGE CHANGE OVER TIME

Chart 4 presents the change in QFCP surcharges over time using a rolling 12-month average figure to smooth out month-to-month changes. Charges started at about $2.40/mWh in Nov 2013 and increased to $4.50/mWh in February 2015.

CHART 4: QFCP ROLLING 12-MONTH AVERAGE



For the 15-month period, QFCP surcharges increased by $2.10/mWh or 88%. Note that this cost is for the QFCP rate alone and does not include the current $3.45/mWh RPS surcharge rate (QFCP + RPS = overall RPCR rate). This extensive cost increase over a short period of time is difficult to mitigate under normal business operations.

DELMARVA POWER RESIDENTIAL COST IMPACT

Delmarva provided a projection of the RPS Program cost impact on Residential customers in their 2014 IRP Plan, See Table 10.

The 2015 compliance year cost per month for an Average Residential customer is shown at $8.27/month and moves upward to $13.38/month in 2024. Delmarva projects that Residential customers are seeing and will continue to experience a similar adverse cost impact from the RPS Program.

These costs are far above any earlier cost projections and dramatically higher than the House of Representatives floor proceedings on 6/29/10. Secretary O'Mara stated that

> "... on the high end estimate that the ratepayer impact will be no more than about 50 cents a month per, per residence. And that's the high-end estimate, ..."[6]

<u>Actual impacts are over 16 times higher and increasing. Even extreme cost projections for Residential consumers never exceeded a level of $1.00 to $1.40 per month. The impact fits the definition of an adverse impact.</u>

Table 10
Impact of RPS compliance on Average Residential Customer Bill (1000 kWh/Month)
(Confidential Material Omitted)

Compliance Year	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025
<u>Avg. Residential Customer Bill (1000 kWh/Month)</u>										
Supply				$83.99	$91.24	$96.86	$98.22	$104.10	$104.11	$102.39
Transmission	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10
Distribution	$42.80	$42.80	$42.80	$42.80	$42.80	$42.80	$42.80	$42.80	$42.80	$42.80
RPS (Includes QFCP)	$8.27	$8.53	$9.43	$10.23	$11.31	$11.72	$12.16	$12.91	$13.33	$13.38
Total				**$149.12**	**$157.45**	**$163.48**	**$165.28**	**$171.90**	**$172.34**	**$170.67**
<u>Solar Compliance Impact on Typical Customer Bill</u>										
SREC Cost	$1.13	$1.42	$1.78	$2.30	$2.84	$3.51	$4.15	$4.73	$5.06	$4.97
SREC % Impact				1.54%	1.80%	2.15%	2.51%	2.75%	2.94%	2.91%
<u>RPS Compliance Impact on Typical Customer Bill</u>										
Total RPS Cost	$8.27	$8.53	$9.43	$10.23	$11.31	$11.72	$12.16	$12.91	$13.33	$13.38
RPS % Impact				6.86%	7.18%	7.17%	7.36%	7.51%	7.74%	7.84%

Note: In Table 10 Transmission and Distribution costs are held constant.

Linde questions the RPS % impact calculations performed by Delmarva in Table 10 above. The process would not be an accurate one for large energy intensive businesses.

To measure the RPS impact, the impact cost should be compared directly against the remaining electric supply costs. This calculation measures exactly how the RPS Program changes electric supply costs.

[6] SS1 HD 6 (O'Mara)

Delmarva adds the RPS cost into the total electric cost and then calculates the % impact. This is not a true measure of how the RPS Program impacts electric supply costs and presents a lower than actual cost impact.

Retail electric suppliers do not provide supply quotes that include Delmarva Power distribution tariff costs for large consumers. Retail suppliers provide quotes based entirely on energy and PJM Ancillary service costs plus their profit margin. Other costs such as Transmission and Capacity are passed through to the consumer at the actual costs. A retail supplier would not assume the risk of price volatility for Transmission, Capacity or RPS Program surcharges embedded in the utility bill.

Further, Delmarva Power by the definition of its Tariff is not a Retail Electricity Supplier for Linde. We do not take Hourly Priced Service from Delmarva Power and by definition take supply from a retail electricity supplier.

<u>Therefore, the correct compliance calculation is to compare the QFCP Surcharge against all the total electricity less the monthly utility invoice.</u>

NOPR 102 SECTION 4 DISCUSSION

<u>CALCULATION CRITERIA FOR ENERGY INTENSIVE CONSUMERS</u>

DNREC should not wait until the end of a compliance year to verify compliance with a 1% or 3% cap cost limit when data to make that determination is readily available every month.

Energy intensive consumers continually monitor and manage electric costs on a daily basis. We are aware of our retail electric cost relationship to the RPS Program surcharge cost. Immediate feedback can be provided to DNREC to assess if surcharge costs exceed the 1% and 3% cost cap limits.

For those companies willing to volunteer to provide monthly compliance cost data to DNREC (assume using a rolling three-month average to soften any month-to-month volatility), DNREC could use this real time feedback on compliance costs to determine when the 3% cap has been reached. Decisions to "Freeze" and "Unfreeze" the RPS Program could be made in real time as well using the actual data.

Linde would volunteer to provide this Compliance cost verification with DNREC in real time effective immediately on a monthly basis. The process would eliminate the requirement for a 150-day evaluation period during which excessive payments with adverse impacts could continue to accumulate.

Linde requests that Section 4 Proposed rulemaking be modified to include a section governing energy intensive customers. For these customers, the compliance evaluations will be performed in real time using actual cost data within the process described above.

GENERIC COST COMPLIANCE CALCULATION, 6/1/13 – 5/31/14 QFCP CHARGE VS. ELECTRIC SUPPLIER COST

Electric supply costs for large commercial and industrial customers can be readily calculated using actual market data. A generic analysis can be performed to identify if RPS Program costs exceed a 3% cap limit of retail electric costs. We will use wholesale electric supply information to conduct our analysis as these are the retail supply offers given to large customers.

Table 4 below illustrates the generic process to calculate the supply costs for a large consumer in the DPL North Zone region.

Energy costs are based on consumption at the DPL Zone North PJM day-ahead prices. Capacity prices are from the PJM Reliability Pricing Model (RPM) market. Transmission costs are charged by PJM using a NITS rate for the individual Transmission Owner (Delmarva Power). PJM Ancillary Services traditionally run at $2/mWh and a Retail Supplier Fee of $1.00 is added to manage load for an end-use customer.

TABLE 4: ELECTRIC COST FOR LARGE DPL NORTH CUSTOMER, 6/1/13 THROUGH 5/31/14

Energy	DPL North Day-Ahead	$55.11/mWh
Capacity [1]	EMAAC	$11.34/mWh
Transmission [2]	DPL NITS Rate	$3.04/mWh
PJM Anc. Services	Historical	$2.00/mWh
Retail Supplier Mgmt. Fee	Historical	$1.00/mWh
TOTAL		**$72.49/mWh**

Using the $72.49/mWh energy cost, a **3% RPS Program cap would limit the fee to $2.18/mWh).**

However, the RPS Program Cost rate for this compliance year was well above the $2.18/mWh figure. Table 5 below shows the QFCP charge by month for the Compliance year. The rate was weighted to reflect the operating hours in a month to show an annual QFCP rate of $3.971/mWh.

[1] Transmission:
$23,938/MW-Year DPL NITS Rate, 90% load factor customer uses 7,884 mWhs per MW of load. Rate per mWh = $23,938/7,884 = $3.04/mWh.

[2] Capacity:
EMAAC value of $245/MW-day, 90% load factor customer uses 21.6 mWhs per MW of load. Rate per mWh = $245/21.6 = $11.34/mWh.

TABLE 5: QFCP ANNUAL RATE FOR 6/1/13 – 5/31/14

Year	Month	Hours	Weighting	QFCP Rate	Eff. Rate
2013	JUN	720	.082	$1.993	$0.158
2013	JUL	744	.085	$2.365	$0.201
2013	AUG	744	.085	$3.680	$0.313
2013	SEP	720	.082	$3.824	$0.314
2013	OCT	744	.085	$4.200	$0.357
2013	NOV	720	.082	$3.886	$0.319
2013	DEC	744	.085	$3.735	$0.318
2014	JAN	744	.085	$4.584	$0.390
2014	FEB	672	.077	$5.262	$0.405
2014	MAR	744	.085	$5.747	$0.489
2014	APR	720	.082	$4.960	$0.407
2014	MAY	744	.085	$3.530	$0.300
TOTAL					$3.971

The compliance year QFCP rate of $3.971/mWh is nearly two times higher than the $2.18/mWh cap limit and would be 5.5% of the electric cost. Note that this generic analysis supports very closely the actual Linde cost experience during the 6/1/13 – 5/31/14 compliance period.

Note: the 2013 Compliance Year was a productive year for evaluating the QFCP project due to the Polar Vortex event in the Winter 2014 and elevated market prices. Typical years will not have such an event and lower energy prices will lead to higher QFCP surcharge rates.

Reviewing the QFCP impact is just one part of the overall Renewable Portfolio Compliance Rate (RPCR). The analysis must include the Renewable Portfolio Standard (RPS) charge as well. That rate was $1.747/mWh for most of the compliance year and then climbed to $3.448/mWh at the end of the year. Adding $1.747/mWh onto $3.971/mWh pushes the total compliance rate up to $5.718/mWh. Compliance costs would now be 7.9% of electric supply cost, an additional 2.4% above the allowable cost cap.

GENERIC COST COMPLIANCE CALCULATION, 6/1/14 – 5/31/15
QFCP CHARGE VS. ELECTRIC SUPPLIER COST

RPS Program costs for the 6/1/14 – 5/31/15 period will increase and exceed the 3% cost cap even further creating more justification for an immediate RPS Program freeze.

The energy rate for 6/1/14 – 12/31/14 has been $33.82/mWh at DPL North, a full $21.29/mWh less than the previous compliance year. There is little chance that the energy rate will come close to the $55.11/mWh level of the previous year. Potential for another Polar Vortex event is extremely limited and the Summer higher cost season has already passed. The 3% cap limit based on Table 6 would be $1.425/mWh.

Therefore, the QFCP cost percentage of 6.1% will be far higher in this current compliance year. Total RPCR costs will soar as the new RPS rate has increased to $3.448/mWh and Capacity Prices dropped substantially. Looking at Table 6 below, the electric cost rate will be around $47.49/mWh. QFCP costs have averaged **$4.438/mWh** so far in the compliance period ($3.646 Jun14, $3.492 Jul14, $3.994 Aug14, $5.355 Sep14, $5.595 Oct14, $4.654 Nov14, $4.329 Dec14). **Therefore, the QFCP rate will be around 9.3%, 6.3% above the cost limit..**

Now add on the RPS portion of the RPCR rate which has been a consistent $3.448/mWh in the compliance period. **Total RPS Program rate reaches 12.8%, over four times the cap limit.**

TABLE 6: ELECTRIC COST FOR LARGE DPL NORTH CUSTOMER, 6/1/13 THROUGH 5/31/14

Energy	DPL North Day-Ahead	$33.82/mWh
Capacity [1]	EMAAC	$6.76/mWh
Transmission [2]	DPL NITS Rate	$3.91/mWh
PJM Anc. Services	Historical	$2.00/mWh
Retail Supplier Mgmt. Fee	Historical	$1.00/mWh
TOTAL		**$47.49/mWh**

Both QFCP and RPCR figures demonstrate severe violations of the 3% cost cap and support the immediate action to freeze the RPS Program and limit further unjustified cost expenditures for Delaware citizens and businesses.

[1] Transmission:
$30,793/MW-Year DPL NITS Rate, 90% load factor customer uses 7,884 mWhs per MW of load. Rate per mwh = $30,793/7,884 = $3.91/mWh.

[2] Capacity:
EMAAC value of $146/MW-day, 90% load factor customer uses 21.6 mWhs per MW of load. Rate per mWh = $146/21.6 = $6.76/mWh.

NOPR 102 SECTION 5 DISCUSSION

Linde requests that Section 5 Proposal will be revised to incorporate the following:

- Director to review the calculations supplied by energy intensive consumers as the compliance cost measure to determine if a 1% or 3% cost cap limit violation is occurring.
- Director to apply an absolute measurement of the cost impact for an energy intensive customer based on total retail supply costs as offered to this customer class (wholesale market determinants with no utility distribution cost). Actual impact to be measured is the Retail Supplier offer made to the customer (no inclusion of utility costs). The % impact calculation is therefore the compliance cost measured against all other supplier costs excluding the compliance cost. Year-on-year changes are not to be considered for this customer class. The Delaware Legislation focused on mitigating adverse rate impacts at a fixed level and did not offer to allow impacts to increase on a year-to-year basis. Otherwise costs could increase by 75% over a 20-year period and the Legislature did not support that type of ratepayer impact.
- Director to apply the 1% and 3% cost cap explicitly as committed to by the Delaware Legislature in June 2010. Proceedings to the House and Senate confirmed that firm "Circuit Breaker" protections would be enforced to limit adverse impacts. There was a direct statement that cost controls were being put in-place to avoid a negative California type cost impact. The rules need to implement the simple and absolute compliance cost cap check per the Code and statements to the Legislature. Delaware did not hear or agree to discretionary evaluations of market conditions or economic development reviews to alter the cost caps.

NOPR 102 SECTION 7 DISCUSSION

Linde recommends that the same actions employed by the Director to implement a "Freeze" for energy intensive customers should be utilized to "Unfreeze" the Program. The measures or process would be identical to Linde's comments under Section 5.

This process ensures equitable treatment to "Freeze" or "Unfreeze" the Program and would utilize real time information for the energy intensive customer class.

Linde volunteers to provide monthly compliance cost data for Section 7 purposes as well.

NOPR 102 SECTION 8 DISCUSSION

Linde requests that Section 8 Proposal will be revised to incorporate the following:

- Revise the 150 day evaluation period to a continuous real time evaluation for energy intensive consumers. The 150 day period is too long a period to potentially expose ratepayers making large monthly payments to excessive costs above cap limits.
- Linde and other energy intensive consumers can provide monthly data to support real time market evaluations.
- The submittal of real time data will eliminate the need to calculate average compliance costs, etc. Energy intensive customers should utilize compliance costs that reflect actual data and not averaged data.
- The comment periods should become an automated process for energy intensive consumers. Implementing the hard cap limits of 1% solar and 3% overall enables a direct comparison of actual cost versus the limit. Comment periods would reflect the actual action taken for energy intensive consumer. The action is an automated one, either Freezing or Unfreezing the Program and there would not be a need to receive or evaluate public comment. The action for this customer class is an absolute one as defined by the "Circuit Breaker" analogy, if the costs exceed or drop below the cap limits, the respective action is implemented, period.

NOPR 102 SECTION 9 DISCUSSION

Linde requests that Section 9 Proposal will be revised to incorporate the following:

- Eliminate the proposed rule making in Section 9 in its entirety.
- Existing contracts must abide by Section §354 cap limits the same as all other RPS Program options. The code requirement is known and has been in-place for over four years and must be followed.
- Commitments made to the Delaware Legislature in June 2010 did not indicate that certain conditions would be allowed to bypass the "Circuit Breaker" type ratepayer cost protections. "Circuit Breakers" do not operate for some conditions and then not operate for other similar conditions. The action is a protective one and it is an absolute action. The cost control limit is applied equally for all applications. Preferential treatment can not be afforded to certain applications. The June 2010 proceedings make no reference to treating certain contracts or applications differently and allowing them to exceed cost caps. Otherwise, the whole intent to eliminate adverse impacts is jeopardized.

CONCLUSION

Linde has provided documentation that the Delaware Legislature received commitments that the expansion of the RPS Program would be performed under very absolute or "Circuit Breaker" ratepayer price protections. Those commitments must be followed. Delaware is experiencing severe adverse price impacts from the RPS Program that were never to occur. Businesses can see impacts approaching or exceeding $1 million a year. <u>Enforcement action was needed some time ago to mitigate the costs</u> imposed by the Program.

There is no doubt that the 1% solar and 3% overall program cost caps have been violated. Linde has provided generic documentation showing the violations and Delmarva Power has published data showing cost impacts two to three times the allowable caps for Residential consumers. Long-term forecasts <u>project a $400 million to $500 million cost for Delaware above market costs</u>.

Immediate action is needed to "Freeze" the RPS Program, reduce Program compliance costs down to the 3% cap level and to credit consumers for overpayments against future costs until the credit has been exhausted.

Vest, Lisa A. (DNREC)

From:	Knotts, Pamela (DOS)
Sent:	Thursday, February 12, 2015 5:47 PM
To:	Vest, Lisa A. (DNREC)
Cc:	Noyes, Thomas G. (DNREC); Loper, Toni (DOS); Marshall, Clishona (DOS); Howatt, Robert (DOS); Dillard, Janis L (DOS)
Subject:	PSC Staff Comment on Cost Cap Rules
Attachments:	PSC Staff's Comments to RPS Cost Cap Rules -2-12-2015.docx

Dear Hearing Officer Vest,
Please see the written comments/suggested revisions of the Public Service Commission Staff on the proposed regulation for Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions.
Thank you for this opportunity to comment.
Pam

Pamela Knotts
Delaware Public Service Commission
Regulatory Policy Administrator
DE Public Service Commission
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Delaware Public Service Commission's Comments on DNREC's Division of Energy and Climate's *Implementation of Renewable Energy Portfolio Standards Act Cost Cap Provisions* as Proposed in the December 1, 2014 Register of Regulations page 432

The Delaware Code permits the State Energy Coordinator, in coordination with the Commission, to freeze the minimum cumulative solar photovoltaics or minimum cumulative eligible energy resources requirement for regulated utilities if the Delaware Energy Office determines that the total cost of complying with this requirement during a compliance year exceeds 1% (minimum cumulative solar photovoltaic requirement) or 3% (minimum cumulative eligible energy resource requirement) of the total retail cost of electricity for retail electricity suppliers during the same compliance year. See 26 **Del. C.** §§354(i) and (j).

The Commission, via its Staff, thanks the Division of Energy and Climate for this opportunity to submit comments/suggested edits to these proposed regulations regarding the implementation of the Renewable Energy Portfolio Standards cost caps. The **Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions** will provide a valuable directive for the calculations to balance the impact of the renewable energy portfolio standards on the ratepayer with the benefits derived from renewable attributes and generation. This rule should define the method of calculating the cost caps that are intended to limit the cost impact of renewables to the ratepayer. The Commission staff is committed to working with the Division of Energy and Climate and all stakeholders to ensure the applicable rules are balanced between the benefits that the Delaware General Assembly finds in renewables and the costs that are paid by the ratepayers.

2.0 Definitions

"**REC cost~~s~~ of compliance**" means the total revenues recovered from customers ~~total costs expended by~~ of the Commission-Regulated Electric Company to achieve the applicable RPS percentage standards for RECs during a respective compliance year.

REC offset cost" and "SREC offset cost" ~~**Surcharge payments**~~" means the total revenues recovered ~~dollar amounts~~ (whether positive or negative) ~~paid~~ under the QFCP-RC tariff, during the respective Compliance year, ~~paid to, or received by~~ from the customers of a Commission-Regulated Electric Company ~~from a QFCPP and a Commission-Regulated Electric Company~~ pursuant to ~~under~~ 26 **Del.C.** §364(d)(1) ~~and an implementing tariff approved by the PSC.~~

"**Renewable Energy Cost of Compliance**" means the total revenues recovered from customers ~~costs expended by~~ of the Commission-Regulated Electric Company to achieve the applicable RPS percentage standards for all renewable energy during a respective compliance year.

"~~**Solar Renewable Energy**~~ **SREC Cost of Compliance**" means the revenues recovered from customers ~~total costs expended by~~ of a Commission-Regulated Electric Company to achieve the applicable RPS percentage standards for solar photovoltaic renewable energy during a respective compliance year.

"**Total Retail Costs of Electricity**" means the total ~~costs paid~~ revenues recovered from ~~by~~ customers of the Commission-Regulated Electric Company for the supply, transmission, distribution and delivery of retail electricity to serve non-exempt customers, including those served by third party suppliers, during a respective compliance year.

4.0 Calculation of the Cost of Compliance

4.1 The Division shall calculate the Renewable Energy Cost of Compliance, the Solar Renewable Energy Cost of Compliance and the Total Retail Cost of Electricity.

4.2 The Division shall calculate the Renewable Energy Cost of Compliance for a particular compliance year to be:

4.2.1 the total of contributions to that portion of the Green Energy Fund used to support the development of renewable resources, plus

4.2.2 the REC Cost of Compliance ~~cost of RECs~~ and the SREC Cost of Compliance ~~SRECs retired~~ used to satisfy the RPS requirement, plus

4.2.3 all Alternative Compliance Payments, plus

4.2.4 the REC Offset Cost and SREC Offset Cost ~~cost of QFCPP offsets~~ to the RPS.

4.3 The Division shall calculate the Solar Renewable Energy Cost of Compliance for a particular compliance year to be:

4.3.1 the total of contributions to that portion of the Green Energy Fund used to support the development of photovoltaic renewable resources, plus

4.3.2 the SREC Cost of Compliance ~~cost of SRECs retired~~ used to satisfy the RPS requirement, plus

4.3.3 all Solar Alternative Compliance Payments for the solar photovoltaic requirement, plus

4.3.4 the SREC offset cost ~~cost of QFCPP offsets~~ used to comply with the solar photovoltaic carve-out.

4.4 The Division will determine the Total Retail Costs of Electricity ~~as all customer costs non-exempt load customers~~ for a particular compliance year.

Vest, Lisa A. (DNREC)

From: Dana Sleeper <director@mdvseia.org>
Sent: Friday, February 13, 2015 11:49 AM
To: Vest, Lisa A. (DNREC)
Subject: Comments: Renewable Energy Portfolio Standards Act established by 26 Del. C. § 354(i) & (j)
Attachments: Proposed DNREC Rules to Implement 26 Del. C. § 354(i) & (j).pdf

Lisa,

Please see the attached letter submitted by MDV-SEIA.

Best,
Dana

Dana Sleeper
Executive Director
(571) 766-8638
dana@mdvseia.org
www.mdvseia.org

BECOME A MEMBER TODAY!

MDV-SEIA

Lisa Vest
Hearing Officer
DNREC
89 Kings Highway
Dover, DE 19901

February 13, 2015

RE: Proposed DNREC Rules to Implement 26 Del. C. § 354(i) & (j)

Officer Vest,

I am writing on behalf of the Maryland, DC, Delaware (DSEC), and Virginia Solar Energy Industries Association (MDV-SEIA). Our organization represents the interests of the solar community – from installers to manufacturers and everyone in between. We are proud to have more than 150 member companies who employ 6,000 workers across the region. We appreciate the opportunity to comment upon the proposed rules to implement 26 Del. C. § 354(i) & (j).

The solar industry currently provides more than 500 jobs[1] in Delaware. Solar jobs increased in the state by more than 40% between 2012 and 2013, driven, in part, by the Renewable Energy Portfolio Standard (RPS). Freezing the RPS would significantly hinder industry growth, result in job losses, and decrease taxable revenue. An RPS freeze would also result in the collapse of the Solar Renewable Energy Credit market and financially harm Delawareans who have already invested in solar power systems.

The General Assembly Recently Rejected Freezing the RPS

A bill, HB 247,[2] that would have frozen the RPS at 8.7 percent was overwhelmingly voted down in a committee hearing in March 2012. Representative Kowalko pointed out that the RPS was intended to create economies of scale that would instead lower prices over time. "You are proposing a repeal of a goal that will cause a shutdown" of those industries, he told Rep. Lavelle. "We're not going to have huge savings by stopping this, but quite to the contrary, new costs imposed on ratepayers and industry."[3]

Those sentiments were echoed by Dr. Tom Earnest, global venture manager at DuPont, which employs 9,500 individuals in the state and has made support of renewables a top company priority. Earnest said that more than $100 million has been invested in clean-energy industries

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[1] The Solar Foundation 2013 Jobs Census. http://pre.thesolarfoundation.org/solarstates/delaware-0

[2] HB 247. http://legis.delaware.gov/LIS/lis146.nsf/vwLegislation/HB+247/$file/legis.html?open

[3] Amid Rising Challenges to State Clean-Energy Mandates, Delaware Lawmakers Reject Effort to Freeze RPS. http://greenmatters.csgeast.org/2012/04/05/amid-rising-challenges-to-state-clean-energy-mandates-delaware-lawmakers-reject-effort-to-freeze-rps/

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MDV-SEIA

in Delaware. "Having an inconsistent policy undermines that drive and deepens our reliance on fossil fuels," he said.

Cost Recovery Year-to-Year

The law allows electricity suppliers to recover dollar for dollar costs incurred in complying with the State of Delaware's RPS' through a surcharge on the supply portion of the ratepayer's electricity bill. This follows the discussions held and language agreed to during the drafting, proposal, and passing of the bill in 2010. Altering this language or any subset of it would significantly diverge from the intention of the original bill. We support the comment letter written on January 24th, 2014 by the Delaware Solar Energy Coalition (DSEC), which has been attached for your convenience.

Recommendation

As the voice of the solar industry and solar community across the Mid-Atlantic region, MDV-SEIA recommends that the language of the proposed rules is appropriate as the statute does not impede the authority of the Director of the Division of Energy & Climate and/or the Division of Energy & Climate to evaluate all pertinent factors when determining the need to institute a freeze on the implementation of the Renewable Energy Portfolio Standard.

Again, thank you for the opportunity to comment upon the proposed rules. We appreciate the work that you and the Division do on behalf of the residents and businesses of Delaware.

Sincerely,

Dana Sleeper
Executive Director, MDV-SEIA

CC: Lisa Vest, Hearing Officer

MDV-SEIA
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DSEC
Delaware Solar Energy Coalition

Lisa Vest
Hearing Officer
DNREC
89 Kings Highway
Dover, DE 19901
Lisa.Vest@state.de.us
(302) 739-9042 fax

January 24, 2014

Re: Delaware Solar Energy Coalition (DSEC) comments on Register Notice SAN #2012-03
102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions

The Delaware Solar Energy Coalition (DSEC) is comprised of solar system owners, companies that install solar systems, manufacturers of solar equipment, and those with an interest in clean renewable energy. Delaware has built a roust industry around solar electrical, employing several hundred Delawareans, and creating over $400M in economic development in the past 5 years.

This boon to Delaware's economy is made possible by the Renewable Energy Portfolio Standard and DNRECs careful custodianship of the rules, regulations and programs controlling the adoption of solar power. DNRECs rulemaking on the Implementation of the Cost Cap provisions will control the future of solar power in Delaware, and determine if the economic and environmental benefits the people of Delaware enjoy due to renewable energy continue, or are sacrificed in the interests of protecting fossil fuel revenues. DSEC offers the following comments in support of ensuring a viable future for solar and other renewable sources of power.

1. The cost of QFCP should not be included in the cost calculations
    a. QFCPs have their own cost caps specifically addressed and calculated in title 26.
    b. While enabled under legislation, natural gas fired fuel cells are not qualified to produce either RECs or SRECs accumulated on PJM-Gats for retirement to satisfy REPS requirements.
    c. QFCP provisions and implementation do not include the actual purchase and retirement of RECs or SRECs. Therefore they do not meet the criteria established for inclusion in cost cap calculations

2. Inclusion of externality calculations
    a. The IRP process has established substantial precedence to suggest that externalities should be considered in the calculation of the retail cost of energy and avoided cost rates.
    b. The IRP also clearly establishes the cost of said externalities.
    c. Such externalities that directly offset RPS costs to ratepayers should be included in cost calculations

3. Avoided Capacity costs
    a. Net metered Renewable Energy Systems provided a capacity value to the grid that is not realized by the system owner.
    b. Wind and Solar projects interconnected to the PJM grid are typically assigned a capacity value ranging from .3-.4 .
    c. The value of this capacity should be calculated as follows:

        (Name plate capacity of net metered systems by technology) X (Average PJM capacity factor by technology) X (average utility demand charge to end use customers)

        The resultant capacity savings should be and subtracted from the RPS compliance cost.

4. Long term Renewable energy costs
    a. Solar Renewable energy system costs do not escalate. Once the systems are paid for thorough initial savings, they continue to generate power throughout the life of equipment, typically measured in decades.
    b. Energy savings to renewable energy system owners should be considered as a reduction in compliance costs.

5. Reducing Volumetric Usage with Distributed Renewable Energy
    a. The installation of distributed renewable energy reduces the amount of power required to be supplied by the utility. This reduction lowers the requirement for SRECs and RECs for the life of the system. The cost savings represented by these volumetric reductions to REPS requirements should be included in the cost calculations.

6. Definitions of May vs. Shall
    a. The statue specifically uses the word "May" to give the Director discretion in determining that if the cost of REPS should exceed the cap, if the ongoing benefits outweigh those costs.
    b. The Director is further instructed to consult with the PSC prior to implementing a freeze, an action that would service no purpose if there was no discretion available to the Director.
    c. The stature then purposefully uses the word 'Shall" to indicate that once a freeze has been implemented, it "Shall" be lifted when the cost cap is no longer exceeded. The Director is specifically not given any discretion, and must lift a freeze once the costs have declined below the cap.
    d. The word "May" directly indicates the use of discretion, while "Shall" indicates a compulsory mandate. It is unreasonable to interpret these words as having an identical definition, particularly as they are used to indicate disparate levels of discretion in the statute.

Thank you for considering our comments.

Dale Davis
President
Delaware Solar Energy Coalition
ddavis@cmielectric.com
(302) 379-6572 cell

DSEC
Delaware Solar Energy Coalition

Rule Making Workgroup: 26 Del. C. § 354(i) & (j) (Renewable Portfolio Standard)

DSEC Initial Comments

Cost Calculation

The items to be included in the cost calculation vary among utility classification.

Under 354 (i) for commission regulated utilities: *"The total cost of compliance shall include the costs associated with any ratepayer funded state solar rebate program, SREC purchases, and solar alternative compliance payments".*

Under 363 (e) for rural electrical cooperatives and municipal electrical companies: *"The total cost of compliance with this section shall include the costs associated with any ratepayer funded renewable energy rebate programs, REC and SREC purchases, or other costs incurred in meeting renewable energy programs."*

The costs associated with administration, vendor fees, legal, accounting and regulatory reviews, or any other cost not directly used to pay grants, purchase SRECs or pay ACP should not be included in the cost calculation for commission regulated utilities. Furthermore, the cost of designing, constructing or operating a Photovoltaic generation facility should not be considered a cost of compliance for any utility classification.

Bloom Energy does not count towards Solar Carve out calculations

Under 352 (25) the RPS definitions a *"Solar Renewable Energy Credit (SREC) means a tradable instrument that is equal to 1 megawatt-hour of retail electricity sales in the State that is derived from solar photovoltaic energy resources and that is used to track and verify compliance with the provisions of this subchapter."*

Natural gas fueled Bloom Energy Fuel Cells do not meet this definition, and the costs associated with them cannot be used in cost cap calculations.

Bloom Energy does not count towards general RPS cost calculations

Under 352 (18) the RPS definitions *"Renewable energy credit" ("REC") means a tradable instrument that is equal to 1 megawatt-hour of retail electricity sales in the State that is derived from eligible energy resources and that is used to track and verify compliance with the provisions of this subchapter."*

Under 352 (6) (e) the RPS defines eligible energy resources to include *"Electricity generated by a fuel cell powered by renewable fuels"*

DSEC ■ P.O. Box 7025, Newark, DE 19714 ■ www.delsec.org ■ PH (877) 229-4555

Until such time as Natural gas has been re-defined as a renewable fuel, or the Bloom Fuel Cells are running on a qualified renewable fuel, the costs associated with those fuel cells cannot be used in cost cap calculations.

Bloom Energy SRECs cannot be used to meet RPS obligations at the current time

Under 352 (16) (a): *"Qualified fuel cell provider" means an entity that*

a. By no later than the commencement date of commercial operation of the full nameplate capacity of a fuel cell project, manufactures fuel cells in Delaware that are capable of being powered by renewable fuels

Under 364 (e): *For purposes of this subchapter, all fuel cell units of a qualified fuel cell provider project under tariff with a commission-regulated electric company shall be considered to have been manufactured in Delaware as long as:*

(1) By no later than the second anniversary of commercial operation of the full nameplate capacity of a fuel cell project, or December 31, 2016, whichever is earlier, either:

a. At least 80% of the installed nameplate capacity shall have been sourced from fuel cell units manufactured in a permanent manufacturing facility located in the State; or

b. No more than 10 megawatts of nameplate capacity from a fuel cell project shall be manufactured outside of the State; and

Until such time as Bloom actually manufactures fuel cells in Delaware, any Bloom Energy installations are not qualified to offset SREC or REC requirements. Bloom has two years from the commencement of operations to begin manufacturing fuel cells in Delaware, at which time units manufactured elsewhere are administratively converted to Delaware manufactured. But until that time, Bloom Energy does not meet the definition of "Qualified fuel cell provider", and therefore Bloom fuel cells do not produce RECs or SRECs that can be used to satisfy the RPS, meaning Bloom costs cannot be used in cost cap calculations.

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The role of the division director in imposing a freeze

From the Oxford Dictionary:

Shall: expressing an instruction or command: *you shall not steal*

May: expressing possibility: *that may be true*

From Dictionary.com:

Shall: (in laws, directives, etc.) must; is or are obligated to: *The meetings of the council shall be public*

May: (used to express possibility): *It may rain.*

Under 354(i): *"The State Energy Coordinator in consultation with the Commission may freeze……"*

And

"The freeze shall be lifted upon a finding by the Coordinator,…"

As both "may" and "shall" were used in the same paragraph, it is reasonable to assume that our legislators know the difference in the definitions. The legislative intent was clearly to provide for the individual most likely to understand all the goals of the RPS to make an informed decision if a cap should be implemented. If the intent was for the cap to be automatic, then there would be no need for the State Energy Coordinator to consult, simple math would suffice. Furthermore, the legislators saw sufficient benefit to the goals of the RPS to absolutely require any such freeze, if imposed, to be lifted once the cap was no longer exceeded. The lifting of the cap was specifically mandated by the word shall, prohibiting any alternate decision.

The cost cap calculation was intended to be incremental, covering increases to cost year over year.

Under 354(1): *"determines that the total cost of complying with this requirement during a compliance year exceeds 1% of the total retail cost of electricity for retail electricity suppliers during the same compliance year."*

The RPS has a goal an intended goal of 3.5% solar. A cumulative calculation would require that solar power cost no more then 1/3 of one percent more than fossil fueled electricity. Such a calculation method would shut down the RPS in the second year. It is reasonable to assume our legislators did not intend for that to occur, and that the incremental year to year calculation would apply.

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Vest, Lisa A. (DNREC)

From:	Gary Myers <garyamyers@yahoo.com>
Sent:	Sunday, February 15, 2015 12:07 AM
To:	Vest, Lisa A. (DNREC)
Cc:	Noyes, Thomas G. (DNREC)
Subject:	REPSA Cost Cap Rule-making, Dec. 1, 2014 NOPR - Supplemental Comments of Gary Myers with Attachments
Attachments:	REPSA 2014 Cost Cap supp. comments cover letter.pdf; RESPA Cost Cap 2014 G. Myers' Supplemental Comments.pdf; REPSA Cost Cap 2014 G. Myers' Supp. Comments - Attachments.pdf

Dear Hearing Officer Vest:

I am attaching to this e-mail, three .pdf files that constitute my Supplemental Comments in the above matter. The files are: (1) a cover letter; (2) the Supplemental Comments; and (3) the Supplemental Comments Attachments. As I indicate in the cover letter, the three electronic files should be linked or connected in order to identify me as the author. .

I ask that the cover letter and the Supplemental Comments with their attachment be made a part of the record in this proceeding. As their title suggests the Supplemental Comments respond to the Legal advice memo that the Division submitted on January 7 and also briefly expand on my comments of Jan. 10 related to whether the Director has the authority to decline to enter a freeze.

I am sending paper copies by US mail on Monday. I am sending electronic copies to Mr. Noyes but I am not sending him paper copies.

Please confirm receipt of the documents and files. If you have any questions, please let me know.

Gary Myers
217 New Castle Street
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<garyamyers@yahoo.com>
(302) 227-2775

217 New Castle Street
Rehoboth Beach, DE 19971
February 15, 2015

Lisa Vest
Hearing Officer
Delaware Department of Natural Resources
and Environmental Control
89 Kings Highway
Dover, DE 19901

By electronic mail and US mail

Re: *DNREC, NOPR 18 DE Reg. 432 (Dec. 1, 2014)*
"102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions"
Supplemental Comments of Gary Myer with attachments

Dear Hearing Officer Vest:

I am submitting the attached supplemental, post-hearing comments for consideration in the above-captioned DNREC rule-making proceeding. I ask that they may be made part of the record in the proceeding.

1. Two filing cautions. The comments and attachments have been constructed separately and contain only a header reference to my name or other identifying information. Consequently, this cover letter should accompany them into the record. Similarly, I have also submitted (as e-mail attachments) electronic copies of the supplemental comments, the supplemental attachments, and this letter. These three electronic files should also be kept linked or connected in order to identify the electronic version of the supplemental comments as mine.

2. Part 1 of these supplemental comments responds to the DNREC "Summary of the legal review on whether the 3 percent and 1 percent costs caps in 26 Del. C. § 354(i), (j) refer to a cumulative increase or year-over-year increase." Although that document was placed in the record at the public hearing on January 7, 2015, I did not receive a copy until January 22. Part 2 of the supplemental comments speaks to the issue of whether the implementation of a freeze is subject to the Director's discretion.

If you have any questions, please contact me. I have only sent electronic copies of this submission to Mr. Noyes.

Respectfully submitted,

Gary Myers
(302) 227-2775
<garyamyers@yahoo.com>

Enclosure
G. Myers' supplemental comments with attachments
on Dec. 1, 2014 NOPR proposed cost cap rules

cc: Thomas Noyes,
Div. of Climate & Energy (w. electronic copies only) (by e-mail only)

Single Year, "Total" Cost RPS Cost Cap Provisions in Other Jurisdictions

Oregon

Ore. Rev. Statutes § 469A.100

(1) Electric utilities are not required to comply with a renewable portfolio standard during a compliance year to the extent that the incremental cost of compliance, the cost of unbundled renewable energy certificates and the cost of alternative compliance payments under ORS 469A.180 exceeds four percent of the utility's annual revenue requirement for the compliance year.

(2) For each electric company, the Public Utility Commission shall establish the annual revenue requirement for a compliance year no later than January 1 of the compliance year. The governing body of a consumer-owned utility shall establish the annual revenue requirement for the consumer-owned utility.

(3) The annual revenue requirement for an electric utility shall be calculated based only on the operations of the utility relating to electricity. The annual revenue requirement does not include any amount expended by the utility for energy efficiency programs for customers of the utility or for low income energy assistance, the incremental cost of compliance with a renewable portfolio standard, the cost of unbundled renewable energy certificates or the cost of alternative compliance payments under ORS 469A.180. The annual revenue requirement does include:

(a) All operating expenses of the utility during the compliance year, including depreciation and taxes; and

(b) For electric companies, an amount equal to the total rate base of the company for the compliance year multiplied by the rate of return established by the commission for debt and equity of the company.

(4) For the purposes of this section, the incremental cost of compliance with a renewable portfolio standard is the difference between the levelized annual delivered cost of the qualifying electricity and the levelized annual delivered cost of an equivalent amount of reasonably available electricity that is not qualifying electricity. For the purpose of this subsection, the commission or governing body of a consumer-owned utility shall use the net present value of delivered cost, including:

(a) Capital, operating and maintenance costs of generating facilities;

(b) Financing costs attributable to capital, operating and maintenance expenditures for generating facilities;

(c) Transmission and substation costs;

(d) Load following and ancillary services costs; and

(e) Costs associated with using other assets, physical or financial, to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs.

(5) For the purposes of this section, the governing body of a consumer-owned utility may include in the incremental cost of compliance with a renewable portfolio standard all expenses associated with research, development and demonstration projects related to the generation of qualifying electricity by the consumer-owned utility.

(6) The commission shall establish limits on the incremental cost of compliance with the renewable portfolio standard for electricity service suppliers under ORS 469A.065 that are the equivalent of the cost limits applicable to the electric companies that serve the territories in which the electricity service supplier sells electricity to retail electricity consumers. If an electricity service supplier sells electricity in territories served by more than one electric company, the commission may provide for an aggregate cost limit based on the amount of electricity sold by the electricity service supplier in each territory. Pursuant to ORS 757.676, a consumer-owned utility may establish limits on the cost of compliance with the renewable portfolio standard for electricity service suppliers that sell electricity in the territory served by the consumer-owned utility.

Ohio

Ohio Revised Code § 4928.64(C)(3)

(3) An electric distribution utility or an electric services company need not comply with a benchmark under division (B) (2) of this section to the extent that its reasonably expected cost of that compliance exceeds its reasonably expected cost of otherwise producing or acquiring the requisite electricity by three per cent or more. The cost of compliance shall be calculated as though any exemption from taxes and assessments had not been granted under section 5727.75 of the Revised Code.

Ohio Administrative Code § 4901:1-40-07 Cost Cap

(A) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with an advanced energy resource benchmark would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(B) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with a renewable energy resource benchmark, including a solar energy resource benchmark, would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric

utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(C) Calculations involving a three per cent cost cap shall consist of comparing the total expected cost of generation to customers of an electric utility or electric services company, while satisfying an alternative energy portfolio standard requirement, to the total expected cost of generation to customers of the electric utility or electric services company without satisfying that alternative energy portfolio standard requirement.

(D) Any costs included in a commission-approved unavoidable surcharge for construction or environmental expenditures of generation resources shall be excluded from consideration as a cost of compliance under the terms of the alternative energy portfolio standard and therefore, would not count against the applicable cost cap. Such costs should, however, be included in the calculation of the total expected cost of generation to customers described in paragraph (C) of this rule.

Maryland

Maryland Code, Public Utilities Companies § 7-705(e), (f)

(e) (1) Notwithstanding the requirements of § 7–703(b) of this subtitle, if the actual or projected dollar–for–dollar cost incurred or to be incurred by an electricity supplier solely for the purchase of Tier 1 renewable energy credits derived from solar energy in any 1 year is greater than or equal to, or is anticipated to be greater than or equal to, 1% of the electricity supplier's total annual electricity sales revenues in Maryland, the electricity supplier may request that the Commission:
(i) delay by 1 year each of the scheduled percentages for solar energy under § 7–703(b) of this subtitle that would apply to the electricity supplier; and
(ii) allow the renewable energy portfolio standard for solar energy for that year to continue to apply to the electricity supplier for the following year.
(2) In making its determination under paragraph (1) of this subsection, the Commission shall consider the actual or projected dollar–for–dollar compliance costs of other electricity suppliers.
(3) If an electricity supplier makes a request under paragraph (1) of this subsection based on projected costs, the electricity supplier shall provide verifiable evidence of the projections to the Commission at the time of the request.
(4) If the Commission allows a delay under paragraph (1) of this subsection:
(i) the renewable energy portfolio standard for solar energy applicable to the electricity supplier under the delay continues for each subsequent consecutive year that the actual or projected dollar–for–dollar costs incurred, or to be incurred, by the electricity supplier solely for the purchase of solar renewable energy credits is greater than or equal to, or is anticipated to be greater than or equal to, 1% of the electricity supplier's total annual retail electricity sales revenues in Maryland; and
(ii) the renewable energy portfolio standard for solar energy applicable to the electricity supplier under the delay is increased to the next scheduled percentage increase under § 7–703(b) of this subtitle for each year in which the actual or projected dollar–for–dollar costs incurred, or to be incurred, by the electricity supplier solely for the purchase of solar renewable energy credits is less than, or is anticipated to be less than, 1% of the electricity supplier's total annual retail electricity sales revenues in Maryland.
(f) (1) Except as provided in subsection (e) of this section, and notwithstanding the requirements of § 7–703(b) of this subtitle, if the actual or projected dollar–for–dollar cost incurred or to be incurred by an electricity supplier solely for the purchase of Tier 1 renewable energy credits other than solar credits or ORECs in any 1 year is greater than or equal to, or is anticipated to be greater than or equal to, the greater of the

applicable Tier 1 percentage or 10% of the electricity supplier's total annual electricity sales revenues in Maryland, the electricity supplier may request that the Commission:
(i) delay by 1 year each of the scheduled percentages for Tier 1 credits under § 7–703(b) of this subtitle that would apply to the electricity supplier; and
(ii) allow the renewable energy portfolio standard for Tier 1 for that year to continue to apply to the electricity supplier for the following year.
(2) In making its determination under paragraph (1) of this subsection, the Commission shall consider the actual or projected dollar–for–dollar compliance costs of other electricity suppliers.
(3) If an electricity supplier makes a request under paragraph (1) of this subsection based on projected costs, the electricity supplier shall provide verifiable evidence of the projections to the Commission at the time of the request.
(4) If the Commission allows a delay under paragraph (1) of this subsection:
(i) the renewable energy portfolio standard for Tier 1 applicable to the electricity supplier under the delay continues for each subsequent consecutive year that the actual or projected dollar–for–dollar costs incurred, or to be incurred, by the electricity supplier solely for the purchase of Tier 1 credits other than solar credits or ORECs is greater than or equal to, or is anticipated to be greater than or equal to, the greater of the applicable Tier 1 percentage or 10% of the electricity supplier's total annual retail electricity sales revenues in Maryland; and
(ii) the renewable energy portfolio standard for Tier 1 applicable to the electricity supplier under the delay is increased to the next scheduled percentage increase under § 7–703(b) of this subtitle for each year in which the actual or projected dollar–for–dollar costs incurred, or to be incurred, by the electricity supplier solely for the purchase of Tier 1 credits other than solar credits or ORECs is less than, or is anticipated to be less than, the greater of the applicable Tier 1 percentage or 10% of the electricity supplier's total annual retail electricity sales revenues in Maryland.

Supplemental Comments of Gary Myers February 15, 2015
DNREC, NOPR, 18 DE Reg. 432 (Dec. 1, 2014)
102 Implementation of Renewable Energy Portfolio Standards
Cost Cap Provisions

1. **The DAG's Advice is Wrong and Proposed Rule §§ 5.2 and 5.3 Fail to Adhere to the "Total Cost," "Single Year" Formula Prescribed in the Plain Text of Subsections 354(i) and (j)**

Based on advice it received from a Deputy Attorney General, the Division has rewritten proposed rule §§ 5.2 and 5.3 to now utilize what it calls a "year-over-year" formula for calculating the cost caps imposed by subsections 354(i) and (j). I earlier offered my views on why the statutory language in those subsections explicitly calls for a formula keyed to comparing "total" compliance costs and "total" retail costs of electricity incurred in a single "compliance year."[1] These supplemental comments will speak to the summary of the DAG's legal advice that the Division has now offered to justify its "year-over-year" formula.

a. Statutory Interpretation and the Division's Role

Delaware is not a *Chevron* jurisdiction for purposes of statutory interpretation and administrative law.[2] Thus, Delaware does not recognize one of the implicit premises of *Chevron*: that the legislature implicitly delegates to administrative agencies the authority to resolve the meaning of ambiguous statutory terms. In this State, statutory interpretation remains ultimately a judicial function. As such, a Delaware agency's job is to faithfully apply the "plain terms" of a statute and, when faced with real textual ambiguity in words or phrases, to "interpret" the text consistent with judicial precedents. Within such a framework, an administrative agency should be extremely reluctant to rely on "absurd results" as any foundation for how the text should be interpreted. Even in the courts, this interpretive tool is not favored. As then-Vice Chancellor Strine has said: the absurd results interpretive maxim "has to be used with great caution and delicacy, lest the judiciary's own sense of appropriate public policy outcomes usurp the powers entrusted to the elected legislative branch."[3] But even more circumspection is called for when an agency - - and particularly one who has sponsored the relevant legislation - attempts to rework statutory terms based on its view that the plain text will lead to results that could not be reasonably attributed to the legislature. For, in that scenario, there lurks the overriding inference that the agency is not interpreting text but commandeering the absurd results canon simply to make an end run around the "the core administrative-law

1 DNREC, NOPR, Comments of Gary Myers at Part 3 (Jan. 10, 2015).

2 *Public Water Supply Co. v. DiPasquale*, 735 A.2d 378, 382-83 (Del. 1999) (*en banc*).

3 *In Re Last Will of Palecki v. Gornik*, 920 A.2d 413, 415 (Del. Ch. 2007) (Strine, V.C.).

principle that an agency may not rewrite clear statutory terms to suit its own sense of how the statute should operate."[4]

b. DNREC is a Bad Champion to Advocate Ambiguity and Absurd Results

DNREC is hardly a good candidate to now belatedly invoke "ambiguity" and "absurd results" to reconfigure the formula for how to calculate the two cost caps. After all, back in 2010, its then-Secretary, Colin O'Mara, was a highly visible and vigorous proponent of SS 1 and its cost cap/freeze provisions. He testified on the floor of the General Assembly in its favor, and repeatedly cited the new "circuit breaker" provisions as "actual price control[s]" that would protect electric consumers from any adverse rate "impacts" arising from the renewable procurement mandates.

Now the Division says the textual language that its then-Secretary so highly touted is either so poorly worded to be a mishmash of ambiguity or, conversely, clearly written but so structured to bring about absurd results. Apparently, Secretary O'Mara missed seeing these rampant ambiguities in the bill that he was endorsing. And it was apparently not just him. A whole host of other stakeholders had worked "pretty feverishly" for six months and "quite intensively" for two weeks on the Substitute Bill before it was finally introduced.[5] Yet, all those participants must also have had a blind eye to the textual ambivalence that the Division now says lurks in the two cost cap provisions.

Then too, since 2010, DNREC has made no effort to go back and have the General Assembly clarify the text and cure the interpretive problem. The PSC's Staff Consultant's Report in the 2011 Bloom Energy proceeding flagged that at least one of the REPSA cost cap provision had the potential to be in play going forward. The PSC Consultant even suggested that DNREC provide an explanation for how DNREC was going about interpreting the cost cap formulas in light of the statutory language. DNREC chose to do nothing in response. For four years, DNREC has had plenty of opportunities to ask the General Assembly to make its intent clear. But DNREC never pursued that course. Now DNREC says it has to be able to rewrite the cost caps formulas in order to avoid "absurd results."

Relying on its DAG's "absurd results" legal advice, the Division has now

4 *Utility Air Regulatory Group v. EPA*, 134 S.Ct. 2427, 2446 (2014).

5 SS 1 SD at 9 (McDowell) (summarizing pre-introduction meetings concerning SS 1).

constructed a "year-over-year" comparative formula for the cost cap subsections. But every one agrees that in the case of the Delaware Electric Cooperative and municipal electric companies the applicable cost cap formulas work on a "within a single year" basis: one that measures and compares the "total" cost of complying with renewable requirements against the "total" cost of purchased power for the calendar year.[6] But DNREC now says, that to avoid absurd results, the cost cap formulas to be applied to Delmarva customers is not one looking to a single "compliance year" but rather a "year-over-year" comparison. That is a different formula than the one that applies to the Co-op and municipal electrics. Thus, the Division's proposed rules create a cost cap formula for Delmarva Power customers that diverges significantly from the formula applicable to the Co-op and municipals. That is a result at odds with what both Secretary O'Mara and Senator McDowell told members of the General Assembly: they said that the same cost cap scheme would apply "across the board" to all the utilities.[7] Consequently, the Division's present stance not only attempts to rewrite clear statutory text but also seeks to reinterpret the legislative history surrounding its enactment.

c. The "Plain Meaning" Text of Subsections 354(i) and (j)

Proposed rule §§ 5.2 and 5.3 now say that the cost of complying is to be measured by comparing the increase in the cost of compliance during this year over last year's compliance cost and then seeing whether that difference exceeds the percentage limit as applied to *this year's* total retail costs of electricity. This scheme is not your typical year-to-year comparison. It does not ask whether (in the case of subsection 354(j)) the cost of compliance this year has gone up 3 per cent over last year's cost of compliance. Nor does it adopt a rule that this year's cost of compliance cannot raise last year's costs of electricity (i.e., last year's rates) by more than 3 per cent. Instead, it measures the difference in compliance costs against 3 percent of *this year's* electric charges. While that might be, in the abstract, a limit of some sort, it does not easily jive with what one would usually call a cap on the year-to-year increase in charges.

But laying this illogic aside, the jumping off point for the new proposed formula is the DAG's initial premise that "the language of this section of the statute *could be* construed as ambiguous." (emphasis added). Unfortunately, the DAG advice summary does not point to the exact word, phrase, or text within either subsection 354(i) or (j) that

6 26 Del. C. § 363(e), (f). These subsections are set forth at page 15 of my comments of January 10, 2015.

7 SS 1 SD at 26-27, 33 (McDowell); SS 1 HD at 12 (O'Mara).

lack clarity and renders the basic structure of the cost cap formula ambiguous. And it is important that the ambiguity go to the structure of the formula, and not simply uncertainty about some of the elements to be plugged in. For example, the phrase "total retail cost of electricity for electric suppliers" is one whose meaning might need careful exploration.[8] Yet that phrase does not speak to the structure of the cost cap formula as between a "single compliance year" comparison or a year-over-year construct. Instead, it describes only one element of the formula. Any ambiguity in that phrase cannot be translated into ambiguity about the structure of the formula. Again, the problem is that the DAG summary does not identify the equivocal words which make the formula structure obscure.

In fact, when one turns to the actual text of the subsections, the wording is pretty precise, and the formula clear. Under both subsections a freeze will be forthcoming if "the total cost of complying with this requirement during a compliance year" exceeds the specified percentage applied to "the total retail cost of electricity for suppliers during the same compliance year." The key words in the text are: (a) "*total*" - for both the cost of compliance and the total retail cost of electricity; (b)"*during* the compliance year" for the total compliance cost; and (c) "*during* the same compliance year" for the total retail electricity cost. What are the commonly understood meanings of those words?[9] The adjective "total" is commonly understood to mean "entire" or "relating to, or constituting, the whole.""[10] "During," as a preposition, is commonly defined as "throughout the course or duration of."[11] Thus, the statutory formula can be recast as one calculating the "entire" cost of complying with the relevant minimum cumulative requirement "throughout the course or duration of" the compliance year and seeing if that number exceeds 3 or 1 percent of the "entire" cost of retail electricity "throughout" the same compliance year.

It's a pretty simple formula. The statutory text suggests a single compliance year for applying the formula: the "total" cost of complying in the particular compliance year

8 Of course, I think that once one puts some effort into thinking about this particular phrase, it does have a clear meaning. *See* DNREC, NOPR, Comments of Gary Myers at Part 5 (Jan. 10, 2015).

9 *New Castle Co. Dept. of Land Use v. Univ. of Delaware*, 842 A.2d 1201, 1207 (Del. 2004) (*en banc*) ("undefined words in a statute must be given their ordinary, common meaning").

10 *The American Heritage dictionary of the English Language* at 1892 "total" (3d ed. 1992).

11 *The American Heritage dictionary of the English Language* at 572 "during" (3d ed. 1992).

and the "total" cost of retail electricity to suppliers "during the same compliance year." There is no mention in the text of measuring year-to-year increases or calculating the difference between last year's and this year's compliance costs (which difference would represent less than the "whole" or "entire" costs of complying during a compliance year).

Instead, "total" costs within a single year are to be compared. Pointedly, that has how the Public Service Commission has read the statutory language. In its RPS rules, the PSC has said:

> 3.2.21 The minimum percentages from Eligible Energy Resources and Solar Photovoltaic Energy Resources as shown in Section 3.2.1 and Schedule 1 may be frozen for CRECs as authorized by, and pursuant to, 26 Del.C. § 354(i)-(j). For a freeze to occur, the Delaware Energy Office must determines [sic] *that the cost of complying with the requirements of this Regulation* exceeds 1% for Solar Photovoltaic Energy Resources and 3% for Eligible Energy Resources of the *total* retail cost of electricity for Retail Electricity Suppliers *during the same Compliance Year.*[12]

Again, in the PSC's rules, there is no mention of any year-over-year comparisons or determining the increase in compliance costs this year over last year's compliance levels. As with the statutory text, the rule calls for comparing the cost of complying with the RPS regulation to the specified percentage of the "total retail cost of electricity for Retail Electricity Suppliers during the same Compliance Year."

Other jurisdictions also use just such a single-year formula in the cost cap limits they have built into their own Renewable Portfolio Standard laws. These other cost cap laws read very much like subsections 354(i) and (j) and impose very similar percentage limitations. *See* Ore. Rev. Stat. § 469A.100 (electric utility not required to comply with a renewable portfolio standard "during a compliance year" to the extent the incremental cost of compliance, the cost of unbundled RECs, and the cost of ACPs "exceeds four percent of the utility's annual revenue requirement for the compliance year"); Ohio Rev. Code § 4928.64(C)(3) (electric distribution utility or electric services company need not comply with renewable benchmark to the extent that its reasonably expected cost of that compliance exceeds its reasonably expected cost of otherwise procuring or acquiring the required electricity by three percent or more); Maryland Code, Public Utility Companies §§ 7-705(e) (electric supplier can request freeze and delay of RPS requirements if actual

12 26 DE Admin. Code 3008 § 3.2.21.

or projected dollar-for-dollar cost incurred by supplier solely for purchase of Tier 1 solar credits in any one year is greater, or equal to, one percent of the supplier's total annual sales revenues), 7-705(f) (same remedy and formula for capping costs expended for non-solar Tier 1 renewable credits; cap set at the greater of either the applicable renewable percentage for that year or ten percent as applied to the supplier's annual sales revenues).[13] Most importantly, no one has ever suggested that these cost cap provisions in other States - either in their description of a single year comparison formula or in their adoption of a 3-4% cap limit - are ambiguous or lead to absurd results.[14]

d. Holes in the DAG's Advice

There are some gaps in the DAG's advice. First, the summary provided says the DAG concluded that the language of the subsections *could* be construed as ambiguous. But as mentioned before, the summary does not identify what language suffers from multiple or unclear meanings. More importantly, the summary never mentions the important textual terms of "*total* cost of complying . . . *during a compliance year*" and "the total retail cost of electricity . . . *during the same compliance year.*" To ignore those terms is to violate the "no surplusage" maxim of statutory interpretation.[15]

Second, the Division justifies its year-over-year cost cap formula based on the DAG's ultimate conclusion that the "percentage caps refer to the statutory compliance schedule, which provides for year-over-year increases." Yet if one looks at the statutory minimum cumulative percentage chart in subsection 354(a) each compliance year's percentage requirement is *not* expressed in a number reflecting the increase above the prior's year's obligation. Instead, the schedule sets forth a "full" compliance number. For

13 The Oregon, Ohio, and Maryland cost cap provisions are reproduced in the attachment to these supplemental comments. The Maryland cap sections have freeze and delay provisions that work very much like the freeze procedures outlined in subsections 354(i) and (j).

14 Maryland imposes a 2 per cent solar requirement by year 2020 and has a 1 per cent of revenues cap on solar compliance costs. Delaware's solar cost cap is the same with a 2.25 per cent solar requirement by 2020. Similarly, Oregon has a 20 percent overall renewable requirement by 2020 subject to a 4 per cent of yearly revenues cap. Delaware has the same 2020 overall renewable goal with a 3 per cent cap on yearly compliance costs.

15 *Sussex County Dept. of Elections v. Sussex County Republican Committee*, 58 A.3d 418, 422 (Del. 2013) ("We presume that the General Assembly purposefully chose particular language and therefore construe statutes to avoid surplusage if reasonably possible.").

example, for the compliance year beginning June 1, 2015, the relevant minimum cumulative percentages are 13 % and 1%. They are not expressed as 2.5 % over the prior year's percentage for overall renewables, or .2 % over the last compliance's year solar mandate. Moreover, the compliance schedule requires Delmarva Power *in each compliance year* to fulfill the *total* percentage figure, not just the difference between this year's compliance percentage and last year's compliance number. The text of the cost cap provisions speak in just such a manner: they ask what was the *total* cost of complying with this t*otal* minimum cumulative percentage in the specific compliance year. And does that amount exceed three percent of the total retail cost of electricity during the same year.

e. Absurd Results?

Subsections 354(i) and (j) assign to the Division the authority to determine whether the cost caps have been breached and to impose a freeze. In so executing such provisions, the Division must necessarily deal with interpreting the language used by the General Assembly. But that task does not accord the Division any power to "tailor legislation to bureaucratic policy goals by rewriting unambiguous statutory terms."[16] So too it "does not include a power to revise clear statutory terms that turn out not to work in practice."[17]

But those two things are exactly what the Division is trying to do when it now relies upon its "absurd results" rationale as the basis for rejecting the textual, single year cost cap formula set forth in subsections 354(I) and (j).

The Division reads the DAG's advice to say that the textual "total" cost, single compliance year formula can be rewritten because "at that rate the statutory compliance schedule could not be achieved." That result, the DAG says, would be an unreasonable or absurd one, which "a court would not find the General Assembly intended." In summary, the DAG seemingly says that any "cost cap" that threatens to become binding, and hence stall the upward march of the RPS requirements, is by definition "absurd" because it would frustrate the "overall" RPS policy. That can't be. If that was the rule, then any cost cap statute would be susceptible to administrative reworking - and non-applicability - at the moment it might become binding.

16 *Utility Air Regulatory Group.,* 124 S.Ct. at 2445.

17 *Utility Air Regulatory Group,* 124 S.Ct. at 2446.

The DAG's advise takes a pretty broad view of the "absurd results" maxim. Under Delaware case law, courts - and administrative agencies - must respect the plain text chosen by the legislature (and Governor) "unless the result is so absurd that it cannot be reasonably attributed to the legislature."[18] That's a "rational basis" test: it asks is there a conceivable rational basis for the result ordained by the text or will that text lead to a totally irrational result? Clearly, the single year, total cost formula set forth in the text subsections 354(i) and (j) passes that inquiry. As noted above, other State legislatures have also adopted just such a formula for cabining excessive costs under those jurisdictions' renewable energy mandates. Commentators have also recognized the existence of such type of formula in many States as a means chosen by the legislative branches to protect consumers against run-away renewable costs brought about by escalating yearly renewable energy purchase requirements.[19]

If anything, the DAG's opinion highlights the opportunity for abuse lurking in the "absurd results" interpretive maxim. Again, as then Vice-Chancellor Strine once said:

> Rather obviously, a judicial decision to refuse to give effect to the only textually-reasonable reading of a statute's words on the grounds that enforcement would work absurd results requires the judiciary to surface and give effect to its own perspective on public policy in a way that risks

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18 *Progressive Northern Ins. Co. v. Mohr*, 47 A.3d 492, 495-96 (Del. 2012) (*en banc*). *See also Kelty v. State Farm Mutual Auto. Ins. Co.*, 73 A.2d 926, 929 (Del. 2013) (*en banc*) ("We give unambiguous statutory language its plain meaning "unless the result is so absurd that it cannot be reasonably attributed to the legislature.") (internal quotation and footnote citation omitted). *Accord Wyatt v. Rescare Home Care*, 81 A.2d 1253, 1260-61 (Del. 2013) ("When the statute is clear on its face and is fairly susceptible to only one reading, the unambiguous text will be construed accordingly, unless the result is an absurdity *that cannot be attributed* to the legislature.") (emphasis added and internal quotation and footnote citation omitted).

19 G. Stockmayer, *et al.*, *Limiting the costs of renewable portfolio standards: A review and critique of current methods*, 42 Energy Policy 155 at § 3. "Annual Cost Caps" (2012) (surveying various State laws using single year, total costs vs. percentage of total revenues cost formulas); J. Heeter, *et al.*, *Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards* at 47-49 (Nat'l Renewable Energy Lab. & Lawrence Berkely Nat'l Lab. May, 2014) (describing Delaware as a "rate impact/revenue requirement" cost cap jurisdiction and noting that Delaware and several other States with similar types of cost caps face binding limitations from such caps).

intrusion on the legislative function.[20]

This risk of abuse is particularly dangerous when the absurd results canon is hauled out in the context of enactments that represent legislative compromise. Here, the 2010 REPSA amendments were the result of many compromises hammered out as Senate Substitute 1 evolved over the months.[21] One such compromise was the cost cap provisions themselves. The 2010 Amendments would increase the yearly percentage numbers for renewables. But the threat of increased consumer costs from such higher percentages loomed over the legislative debates.[22] To dampen those concerns, the new cost cap provisions were touted. With them, proponents said, consumers would be protected against runaway costs that might arise from the higher numbers. That is how the legislation was sold on the legislative floor.[23]

The DAG's absurd results analysis would break the legislative deal. Under the guise of statutory interpretation, the DAG says that the Division can value one goal - achieving the yearly renewable resource percentages - over another, protecting consumers against run-away renewable costs. The DAG says the single year formula set forth in the statute leads to absurd results because it would frustrate achievement of the escalating renewable energy portfolio purchase benchmarks. But, on the other hand, the "year-over-year" comparison formula now offered by the Division works at the other extreme. It ensures that no cost constraint on renewable energy costs could ever become binding. The DAG's analysis impermissibly allows the Division to value the former goal over the cost cap restraint.

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20 *Palecki,* 920 A.2d at 425. The danger is not eliminated simply because one might be able to tease some ambiguity out of the statutory text. Again, in Vice-Chancellor Strine's words:

> But, even then, that interpretative exercise is a very sensitive one that can be subject to (conscious or unconscious) abuse, as it provides room for the judiciary to give license to its own sense of appropriate public policy outcomes, by labeling outcomes it finds disquieting as "absurd" or "unreasonable."

Id., 920 A.2d at 423-24.

21 SS 1 SD at 9 (McDowell (describing SS 1 as "compromise').

22 SS 1 HD at 5-6, 7, 13 (questions of Rep. Kovach); SS 1 SD at 11-12 (questions of Sen. Bonini), 13 (questions of Sen. Venables).

23 SS 1 HD at 6-8, 13-14, 18 (O'Mara); SS 1 SD at 5-6, 26-27 (McDowell).

The Supreme Court has recognized the mischief in this type of absurd results analysis. It has said:

> The "plain purpose" of legislation, however, is determined in the first instance with reference to the plain language of the statute itself. Application of "broad purposes" of legislation at the expense of specific provisions ignores the complexity of the problems Congress is called upon to address and the dynamics of legislative action. Congress may be unanimous in its intent to stamp out some vague social or economic evil; however, because its Members may differ sharply on the means for effectuating that intent, the final language of the legislation may reflect hard-fought compromises. Invocation of the "plain purpose" of legislation at the expense of the terms of the statute itself takes no account of the processes of compromise and, in the end, prevents the effectuation of congressional intent.

Board of Gov. of Fed. Reserve Bd. v. Dimension Financial Corp., 474 U.S. 361, 373-74 (1986). *See Palecki*, 920 A.2d at 427 n. 47 (citing *Barnhart v. Sigmon Coal Co.*, Inc., 534 U.S. 438, 441 (2002) with description of that case as "noting that statutes are often delicately crafted in process of legislative compromise and rejecting application of an absurd results test to alter an unambiguous statute in order to satisfy policy preferences better fought out in other arenas"). *Compare Rodriguez v. United States*, 480 U.S. 522, 525-26 (1987) (*per curiam*) ("Deciding what competing values will or will not be sacrificed to the achievement of a particular objective is the very essence of legislative choice - and it frustrates rather than effectuates legislative intent simplistically to assume that whatever furthers the statute's primary objective must be the law."); *Ragsdale v. Wolverine World Wide Inc.*, 535 U.S. 81, 93-94 (2002) ("Like any key term in an important piece of legislation the [] figure was the result of compromise between groups with marked but divergent interests in the contested provision. . . . Courts and agencies must respect and give effect to those sorts of compromises.").

The two cost cap subsections, fairly read, describe a single year, "total" cost formula to constrain excessive expenditures under the renewable energy mandates. Nothing in the "absurd results" canon allows the Division to rewrite the formula to satisfy the agency's own view that more renewable energy - even with high costs and high rate impacts - is the better policy. The Division must follow the plain text, strike its new §§ 5.2 and 5.3, and revert to the statutory formula correctly embraced in its December, 2013 proposed rules.

2. The Word "May" Does Not Authorize the Discretionary Freeze Superstructure Set Forth In Proposed Rules §§ 5.4-5.8

The Division supports its discretionary freeze superstructure by relying on the use of the "may freeze" phrase in both subsections 354(i) and (j). The word "may," the Division suggests, awards not just permission, but also discretion. As set forth in part 4 of my January 10, 2015 comments, the historical case law surrounding the meaning of the word "may" - as it applies in this context - suggests that the term imposes an obligation on the public officer, not just a discretionary power.

In fact, most dictionaries acknowledge such notion of obligation or duty in the word "may" when it is used in legal texts to describe an official's duty to enforce a right granted by statute. In that scenario, the presumptive definition is to equate "may" to a required duty, rather than the power to exercise some discretion. *See The American Heritage dictionary of the English Language* at 1112 "may" (3d ed. 1992) ("5. To be obliged; must. Used in statutes, deeds, and other legal documents."); *Webster's New World College Dictionary* at 889 "may" (4th ed. 1999) ("6. *Law* shall; must"); *Black's Law Dictionary* at 1127 "may" (10th ed. B. Garner editor 2014) ("3. Loosely, is required to; shall; must . .... In dozens of cases, courts have held *may* to be synonymous with *shall* or *must*, usu. in an effort to effectuate what is said to be legislative intent.").

In fact, the Delaware Supreme Court has said that while "may" can be generally viewed as a grant of permission, the question of whether the exercise of such permission is discretionary or obligatory turns on context. *Miller v. Spicer*, 602 A.2d 65, 67 (Del. 1991). There the State statutory anti-discrimination scheme said that a victim of discrimination "may file" a complaint before the supervising administrative agency. The victim argued that the use of the term "may" made the administrative remedy not just permissible, but discretionary. As he saw it, the word "may" meant he was free to pursue an independent, judicial private cause of action for the discriminatory injury prescribed by the statute. If the administrative remedy was to be exclusive, he said, the statutory text would have read "shall." The Court said that while the term "may" normally is seen as a grant of permission "the test is a contextual one and the mere use of a term does not control the question of legislative intent if the statute suggests a different construction." 602 A.2d at 67. To the Court, the use of the term "may file" was consistent with a notion - not of discretion - but of obligation: if the injured victim was going to pursue remedies, he had to use the exclusive administrative remedy set forth in the statute.

In context, subsections 354(i) and (j) make the declaration of a freeze obligatory if the Division makes the relevant cost cap determination. The text of the two subsections do not speak in terms of discretion: neither has any listing of the factors to be used in the exercise of any such purported discretion. In fact, as outlined in part 4 of my earlier January 15 comments, the legislative history of the subsections - rife with descriptions of the cost caps as automatic "circuit breakers" - paints a far different picture than a scheme where the Director can forego a freeze and continue to force customers to pay "above cap" renewable charges. Then-Secretary O'Mara captured the cost cap scheme most precisely when he told the House members:

> But most importantly, by having a circuit breaker, if you will, an actual price control, whereby if the, *if the ratepayer impacts exceed a certain amount, that the entire program freezes in place,* we can ensure ratepayers that there won't be any adverse impacts from this legislation.[24]

The subsections do not allow for the Division's discretionary freeze superstructure.

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24 SS 1 HD at 6-7 (O'Mara) (emphasis added). *See also* SS 1 HD at 7-8 (O'Mara) ("This does add, as I mentioned, *the circuit breaker that does freeze the program* if there are adverse rate impacts.") (emphasis added).

From:	Firestone, Jeremy Mark <jf@udel.edu>
Sent:	Monday, February 16, 2015 10:06 AM
To:	Vest, Lisa A. (DNREC)
Cc:	Noyes, Thomas G. (DNREC)
Subject:	Public comment on Renewable Energy Portfolio Standards Cost Cap regulation
Attachments:	Comments of Jeremy Firestone on DNREC revised proposed RPS caps rules 16 Feb 2015.pdf

Dear Ms. Vest,

Please find attached comments on the proposed regulation.

Sincerely,

Jeremy Firestone

Jeremy Firestone
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CCPI

Comments of Jeremy Firestone[1] on Revised Proposed Rules for RPS Cost Caps

February 16, 2015

I have reviewed the revised proposed rules. A number of changes[2] were made that improve substantially the revision of the 2013 proposed rules, one of which I will comment on. In addition, there are several additional changes that should be made to bring the rules into compliance with the statute.

First, those instances where changes in the proposed rule are required to bring the rules into conformance with the statute:

1. The proposed rules (section 4.2.1) include the costs related to the Green Energy Fund in compliance cost, but section 354 (j) refers to the cost of complying with "this" requirement. This requirement is the RPS, referred into in earlier subsections of section 354. The Green Energy Fund is an entirely different part of the code, in Title 29 rather than Title 26. In addition, the Green Energy Fund was adopted in 2003 as part of the Delaware Energy Act, while the RPS was adopted in 2005. As such, the Green Energy Fund is unquestionably outside of scope of "this" requirement,

2. The statute is clear: any such freeze (or lifting of the freeze) is tied to an "exceedance" of the 3% and 1% thresholds. The proposed rules (5.2; 5.3) however provide she may do so if the costs are "equal to" or are greater than the applicable threshold and shall lift the freeze if the cost of compliance falls below that threshold. When the General Assembly is clear, DNREC does not have discretion. "Exceeds" means "greater than" not "equal to or greater than."

3. The proposed rules (7.3) provide that the Director " "shall lift" if the total cost of compliance falls below the threshold; as noted above, it should be if it "equals or falls below" the applicable thresholds. Moreover, under the statute the Director is required to lift the freeze if it can be "reasonably be expected" to be under an applicable

[1] Professor, University of Delaware, School of Marine Science and Policy, and Director, Center for Carbon-free Power Integration (CCPI), www.carbonfree.udel.edu.
[2] When DNREC issues a modified proposed rules it should provide a redline version of the earlier proposal in addition to a clean copy of the modified proposal. That citizen-friendly approach would greatly assist citizens and provide only minimal burden on the Department.

threshold. Thus, the statute does not require certainty ("if"), but rather, "if the Director reasonably expects."

Second, the statute provides, for example, that a freeze may be instituted if the "total cost of complying with this requirement during a compliance year exceeds 3% of the total retail cost of electricity for retail electricity suppliers during the same compliance year. DNREC has modified the prior draft in Sections 5.2 and 5.3, so that the 1% and 3% price thresholds are now linked to a year-to-year increase in the cost to ratepayers. This raises the issue of whether that interpretation is consistent with legislative intent. While apparently, Delaware courts have not as of yet afforded so-called Chevron deference to administrative interpretations, as would be applied to a federal agency, administrative conclusions of law are reviewed "with a deferential bent, which recognizes the expertise of the agency in adjudicating disputes in that field." Camtech School of Nursing and Technological Sciences v. Delaware Board of Nursing, C.A. No. 13A-05-004 RRC, (Superior Court, January 31, 2014)

I examined the debates in the General Assembly, although one needs to exercise caution in attributing the statements of individuals as being representative of the General Assembly as a whole. Senate Sponsor, Senator Harris McDowell, stated that a "circuit breaker" would suspend the participation for "one year" in the event that prices "go up by 1% in a year"(with a parallel circuit breaker for the 3% threshold). Senate Debate on Senate Substitute No. 1 for Senate Bill No. 119 (June 22, 2010), 145th General Assembly, p. 9, lines 12-20. See also p. 27 ("their rates go up in one year by 1 percent"). In the House, DNREC Secretary Collin O'Mara likewise stated that: "You'll never have more than a 1 percent impact for a given year for solar." House Debate on Senate Substitute No. 1 for Senate Bill No. 119 (June 29, 2010), 145th General Assembly, p. 13, lines 22-24.

Thus, DRNEC's interpretation does find support in the debates of the General Assembly from prominent parties. As well, such an interpretation makes sense from a policy standpoint. If it were otherwise, it could lead to the anomalous result that a freeze becomes more likely the greater the fraction of renewable energy certificates held, when from a cost-benefit perspective, there is a vast difference between consumers paying 3% of retail costs for RECs for renewable energy resources equal to 5% of load and that same percentage (3%) for renewable energy resources equal to 25% of load. DNREC's construction avoids that anomalous result, by tying circuit breakers to year-to-year increases. Given that year-to-year rate increases are likely at least of the same magnitude, if not more, of a concern to ratepayers (and hence the General Assembly) than are total costs, DNREC's construction also makes sense.

In sum, given the court's deferential bent and DNREC's expertise, DNREC's construction of the statute is reasonable and indeed, has policy support, and thus is justified.

Vest, Lisa A. (DNREC)

From:	Coralie Pryde <prydeca@verizon.net>
Sent:	Sunday, February 15, 2015 8:46 PM
To:	Vest, Lisa A. (DNREC)
Subject:	Comment on proposed RPS Cost Cap Regulations
Attachments:	RPS Cost Cap comment Pryde.doc

Dear Ms. Vest:

I've attached my comments below. Thank you for extending the comment period.

Coralie Pryde

Lisa A. Vest
Public Hearing Officer
DNREC
Office of the Secretary
89 Kings Highway
Dover, DE 19901

Dear Ms. Vest:

I strongly support proposed *Regulation 102 Implementation of Renewable Energy Portfolio Standards Cost Cap.* I believe that the step-by-step directions for calculating the cost of compliance (**4.1- 4.4**) should be very helpful in preventing future misinterpretations of or confusion about the law.

The detailed description under **5.0 (Determination by the Director)** of the specific factors to be used in determining whether or not to order a freeze is of real value. The language currently used in the Renewable Energy Portfoliio (RPS) Act in Section 354(i) & (j) makes it clear that the decision to order a freeze is made at the discretion of the Director of the Division of Energy and Climate for DNREC, rather than mandating that a freeze must be instated whenever the Cost Cap is exceeded. However, this existing wording does not define what aspects of the extant energy situation should be considered in arriving at a decision. The listing of these factors in proposed Regulation 102 provides useful information for all who are interested in the RPS and can serve as a guide for future Directors.

I am also pleased that the issues of the externalities involved in extraction and use of fossil fuels and the economic benefits of creating new jobs in renewable energy are clearly listed under **5.0**. These are extremely important factors that are too often ignored in economic discussions focusing on the immediate cost or price to the consumer.

I thank Tom Noyes for explicating the rules and conditions under which the Director of the Division of Energy and Climate may implement a freeze of Delaware's Renewable Energy Portfolio Standards. He has taken a subject that might well be considered impossibly arcane and broken it down into clear directions.

Sincerely,

Coralie A. Pryde

Vest, Lisa A. (DNREC)

From:	Maucher, Andrea (DOS)
Sent:	Monday, February 16, 2015 12:25 PM
To:	Vest, Lisa A. (DNREC)
Cc:	Bonar, David L (DOS); Price, Ruth A (DOS); Iorii, Regina (DOJ)
Subject:	Comments on DNREC Proposed Cost Cap Rules
Attachments:	DPA formal comments on proposed Section 354 regulations_final.pdf

Dear Ms. Vest –

The Delaware Division of the Public Advocate hereby submits the attached comments regarding the Department of Natural Resources and Environmental Control's proposed rules Implementing 26 Del. C. §§354(i) and (j), as published in the December 1, 2014 Delaware Registrar of Regulations.

Regards,

Andrea B. Maucher
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COMMENTS OF THE DELAWARE DIVISION OF THE PUBLIC ADVOCATE ON THE PROPOSED RULES TO IMPLEMENT 26 *DEL. C.* §§354(i) AND (j) PROMULGATED BY THE DELAWARE DEPARTMENT OF NATURAL RESOURCES AND ENVIRONMENTAL CONTROL

The Delaware Division of the Public Advocate ("DPA") hereby submits the following comments ("Comments") regarding the Department of Natural Resources and Environmental Control's ("DNREC") proposed rules (the "Proposed Rules") Implementing 26 *Del. C.* §§354(i) and (j).

I. The Proposed Rules Are Void *Ab Initio* Because The Commission, Not DNREC, Has the Authority to Promulgate the Rules That Will Determine the Procedures for Freezing the RPS Requirements.

DNREC says that the authority supporting these regulations is 26 *Del. C.* §§354(i) and (j). And those sections do say that the Director, in consultation with the Commission, will determine whether a freeze should be imposed. But those sections do not give DNREC the authority to promulgate regulations to specify the procedures for freezing the RPS requirements, as DNREC apparently believes. Rather, in 26 *Del. C.* 362(b) (also part of the REPSA), the General Assembly expressly gave that authority to the *Public Service Commission:*

> For regulated utilities, the Commission shall further adopt rules and regulations *to specify the procedures for freezing the minimum cumulative solar photovoltaic requirement as authorized under § 354(i) and (j) of this title,* and for adjusting the alternative compliance payment and solar alternative compliance payment as authorized under § 358(d)(4) and (e)(3) of this title.

(Emphasis added). And Section 352(2) of the REPSA defines "Commission" as the Delaware Public Service Commission, not DNREC.

It could not be clearer that the *Commission*, not DNREC, is responsible for promulgating rules and regulations to specify the *procedures for the freeze* discussed in Sections 354(i) and (j).[1],[2] The statute does not give the Commission authority to delegate its responsibility for specifying the procedures for freezing the RPS requirements to DNREC, and the Commission cannot delegate its authority *sua sponte*. Since DNREC does not have the authority to specify the procedures for implementing a freeze, any regulations issued by it are void *ab initio* and unenforceable.

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[1] The DPA notes that Section 362(b) does not specifically identify "eligible energy resources" as subject to the Commission's regulation, but it *does* explicitly refer to both sections 354(i) and (j). And Section 354(j) addresses eligible energy resources. Therefore, the DPA concludes that the General Assembly did in fact include both types of renewable energy resources as subject to regulation by the Commission with respect to establishing procedures for freezing the RPS requirements.

[2] The Commission did issue regulations. *See* 26 *Del. Admin. C.* Part 3008 – Rules and Procedures to Implement the Renewable Energy Portfolio Standard. In Section 3.2.21 thereof, however, the Commission appears to delegate the responsibility for issuing procedures to implement 26 *Del. C.* §§354(i) and (j) to DNREC. This is impermissible.

II. Sections 2.0, 4.2, 4.3 and 4.4: Assuming *Arguendo* That DNREC Has the Authority to Promulgate Regulations to Implement 26 *Del. C.* §§354(i) and (j), The Proposed Rules' Definition of "Total Retail Costs of Electricity" Should Not Include the Costs of Transmission, Distribution or Delivery of Electricity – But If Those Functions Remain In the Definition, They Should Be Added to the Definition of "Renewable Energy Costs of Compliance" to Enable a Fair Comparison.

DNREC's proposed definition of "Total Retail Costs of Electricity" includes costs associated with the transmission, distribution and delivery of electricity. This is improper. Section 354 is concerned solely with *supply* of electricity, not with transmission, distribution or delivery of electricity. As a result of deregulation, those functions were unbundled. The "Total Retail Costs of Electricity" should include only those costs related to the supply function. The DPA prefers removing the transmission, distribution and delivery costs from the definition of "Total Retail Costs of Electricity." That definition could instead be called "Total Retail Costs of Electricity Supply." We submit that this change more accurately reflects the statutory language (which is limited to renewable energy mandates) and certainly is more consistent with the intent of the sponsors of the amendments to Section 354, who emphasized over and over again that the sections provided a "circuit breaker" to protest ratepayers in the event the renewable energy mandates became too expensive (defined by the General Assembly as the 1% increase for solar and 3% for eligible energy resources).

If DNREC is determined to include transmission, distribution and delivery costs in the "Total Retail Costs of Electricity," then transmission, distribution and delivery costs should also be included in the definition of "Renewable Energy Costs of Compliance" and in Sections 4.2 and 4.3 of the Proposed Rules. Since renewable energy also has to be transmitted, distributed and delivered, these costs are appropriately included in the definition *if* they are also included in the "Total Retail Costs of Electricity." Their inclusion would enable a true "apples to apples" comparison of "Renewable Energy Costs of Compliance" with "Total Retail Costs of Electricity" such that the only difference between the two would be the costs associated with the renewable energy mandates. Excluding transmission, distribution and delivery costs from the definition of "Renewable Energy Costs of Compliance" but including them in the definition of "Total Retail Costs of Electricity" will almost guarantee that the 1%/3% thresholds for implementing a freeze pursuant to the provisions of 26 *Del. C.* §§354(i) and (j) will never be reached.

III. Sections 5.2 and 5.3: Assuming *Arguendo* That DNREC Has the Authority to Promulgate Regulations to Implement 26 *Del. C.* §§354(i) and (j), DNREC Has Exceeded Such Authority Under 26 *Del. C.* §§354(i) and (j) By Adding the Language "Over the Previous Compliance Year" and By Writing the Commission Completely Out of the Determination of Whether to Implement a Freeze.

A. The Statutes Are Clear That the Appropriate Comparison Is the "Same Compliance Year," Not a Comparison of the Current Compliance Year to Some Earlier Compliance Year.

The rules of statutory construction are well settled. First, we must decide if the statute is ambiguous. A statute is ambiguous if it is susceptible of two reasonable

> interpretations or if a literal reading of its terms "would lead to an unreasonable or absurd result not contemplated by the legislature." If it is unambiguous, *then there is no room for judicial interpretation and "the plain meaning of the statute controls."* If, on the other hand, the statute is ambiguous, then we consider it as a whole and we read each section in light of the others to produce a harmonious whole. *Only when a statute is ambiguous do we look for guidance to its apparent purpose and place it as part of a broader statutory scheme.* ...

PHL Variable Insurance Co. v. Price Dawe 2006 Insurance Trust, 28 A.3d 1059, 1070 (Del. 2011) (internal quotation marks and sources omitted); *see also Taylor v. Diamond State Port Corp.*, 14 A.3d 536, 538 (Del. 2011); *Dewey Beach Enterprises, Inc. v. Board of Adjustment of the Town of Dewey Beach*, 1 A.3d 305, 307 (Del. 2010).

26 *Del. C.* §354(i) provides:

> The State Energy Coordinator in consultation with the Commission, may freeze the minimum cumulative solar photovoltaics requirement for regulated utilities if the Delaware Energy Office determines that the total cost of complying with this requirement *during a compliance year* exceeds 1% of the total retail cost of electricity for retail electricity suppliers *during the same compliance year*. In the event of a freeze, the minimum cumulative percentage from solar photovoltaics shall remain at the percentage for the year in which the freeze is instituted. The freeze shall be lifted upon a finding by the Coordinator, in consultation with the Commission, that the total cost of compliance can reasonably be expected to be under the 1% threshold. The total cost of compliance shall include the costs associated with any ratepayer funded state solar rebate program, SREC purchases, and solar alternative compliance payments.

(Emphasis added). 26 *Del C.* §354(j) similarly provides:

> The State Energy Coordinator in consultation with the Commission, may freeze the minimum cumulative eligible energy resources requirement for regulated utilities if the Delaware Energy Office determines that the total cost of complying with this requirement *during a compliance year* exceeds 3% of the total retail cost of electricity for retail electricity suppliers *during the same compliance year*. In the event of a freeze, the minimum cumulative percentage from eligible energy resources shall remain at the percentage for the year in which the freeze is instituted. The freeze shall be lifted upon a finding by the Coordinator, in consultation with the Commission, that the total cost of compliance can reasonably be expected to be under the 3% threshold. The total cost of compliance shall include the costs associated with any ratepayer funded state renewable energy rebate program, REC purchases, and alternative compliance payments.

(Emphasis added).

It could not be clearer that the General Assembly meant for the comparison to be between these items for *the same compliance year*. Apparently DNREC originally thought so too: in its first iteration of the Proposed Rules, Sections 5.2 and 5.3 stated that "If the Division calculations show that the (Solar)/Renewable Cost of Compliance is equal to or greater than 1%/3% of the Total Retail Cost, the Director shall determine whether a freeze should be implemented."

But somewhere between its first iteration of the Proposed Rules and the current one, DNREC apparently realized that interpreting the statutes exactly as they were written meant that it would have to consider implementing a freeze just about every year. The following table comes from Delmarva Power & Light Company's 2012 Integrated Resource Plan (which has been unsealed and is publicly available). The table shows that starting with Compliance Year 2013/14, the cost of complying with the requirements for renewable energy resources on an average customer's bill would exceed the 3% threshold of 26 *Del. C.* §354(j), and starting with compliance year 2017/18, the cost of complying with the requirements for solar renewable energy resources on a customer's bill would exceed the 1% threshold of 26 *Del. C.* §354(i).

Table 10

Impact of RPS Compliance on Typical Residential Customer Bills

Compliance Year	2013/14	2014/15	2015/16	2016/17	2017/18
Avg. Residential Customer Bill (1000 kW/Month)					
Supply Component	$89.32	$107.30	$120.30	$136.68	$151.65
Transmission Component	$6.72	$6.85	$6.99	$7.13	$7.34
Distribution Component	$30.30	$30.91	$31.53	$32.16	$33.14
Total	$125.97	$145.06	$158.82	$175.98	$192.13
Solar Compliance Impact on Typical Customer Bill					
Total SREC Compliance Cost per Avg Bill (1000 KW)	$0.91	$1.32	$2.19	$3.35	$5.27
SREC % Impact on Avg. Customer Bill	0.72%	0.91%	1.38%	1.90%	2.74%
RPS Compliance Impact on Typical Customer Bill					
Total RPS Compliance Cost per Avg Bill (1000 KW)	$6.60	$8.10	$9.18	$11.24	$15.15
	5.24%	5.58%	5.78%	6.39%	7.88%

(2012 Integrated Resource Plan at 102).

To avoid having to consider a freeze as soon as these rules become effective, the current iteration of the Proposed Rules now provides that the comparison will be made from one compliance year to the next, rather than within the same compliance year. The revised Sections 5.2 and 5.3 provide:

> If the Division calculations show that the increase in the (Solar) Renewable Energy Cost of Compliance *over the previous compliance year* is equal to or greater than 3% of the Total Retail Cost of Electricity, the Director shall determine whether a freeze should be implemented.

According to DNREC, its change of position is based on legal analysis it received from a Deputy Attorney General assigned to this matter. DNREC will not share the actual opinion from the deputy because it claims that it is protected by the attorney-client privilege, but it provided a "summary" of that advice at the January 7, 2015 public comment session. Here is what that summary said:

> The DAG reviewed the record in this proceeding and noted that commenters to the proposed rule questioned whether the cost cap provision refers to the total cost of compliance or the incremental or annual change in the cost of compliance. The DAG also noted that the language of this section of the statute could be construed as ambiguous, and as such, a reviewing court would look at the statute as a whole to understand the General Assembly's intent. A court would refer to Section 354(a), which sets forth the compliance schedule on a year-by-year basis through 2025. Interpreting the statute so that the minimum cumulative requirement refers to the cumulative increase from the beginning of the program would lead to an unreasonable or absurd result because at that rate the statutory compliance schedule could not be achieved, and that a court would not find that the General Assembly intended that result,. Therefore, the percentage caps refer to the statutory compliance schedule, which provides for year-over-year increases.

(Exhibit A).

This compares the wrong things. It is not whether the starting point should be the beginning of the program and the ending point should be the current compliance year. Rather, the statutory language clearly contemplates that the comparison is between the Total Retail Cost of Electricity and the total cost of complying with the RPS requirement *for the same compliance year.* There is nothing ambiguous about this, and the canons of statutory interpretation upon which DNREC relies to justify its reference to a different section of the statute do not come in play when a statute is clear on its face: "If [the statute] is unambiguous, *then there is no room for judicial interpretation and "the plain meaning of the statute controls." PHL, supra; Taylor, supra; Dewey Beach Enterprises, supra.* (Emphasis added).

DNREC has not shared with anyone what language in the statutes leads it to conclude that the statutes are ambiguous. But they are not ambiguous. Had the General Assembly wanted to make the comparison between current costs and last year's costs, it certainly knew how to do so. But the General Assembly did not want that to be the comparison. It wanted the comparison to be between the total electricity costs and the RPS/solar compliance costs for the *same compliance year*.

In imposing a comparison of current compliance year costs to last year's compliance year's costs, DNREC has rewritten the statute. This is inappropriate. DNREC is bound by the language of the statutes; it cannot simply rewrite Sections 354(i) and (j) to suit itself or to reach a conclusion that is more palatable to it:

> Legislation … may not be enacted under the guise of its exercise by adopting a rule or regulation which is out of harmony with, or which alters, extends or limits the Act, or which is inconsistent with clear legislative intent as therein expressed.

Wilmington Country Club v. Delaware Liquor Commission, 91 A.2d 250, 255 (Del. Super. 1952).

Therefore, Sections 5.2 and 5.3 of the Proposed Rules must be amended to remove the reference to "the previous compliance year."

B. The Proposed Regulations Ignore the Role of the Delaware Public Service Commission in Determining Whether a Freeze Should Be Implemented.

Both Sections 354(i) and (j) provide that the State Energy Coordinator (now the Director of the Division of Energy & Climate) "in *consultation with the Commission*" (that is, the Delaware Public Service Commission) may freeze the minimum cumulative solar photovoltaics/eligible energy resource requirements. (Emphasis added). These provisions clearly envision that the Commission *will* be involved in determining whether there should be a freeze in the first place.

Sections 5.2 and 5.3 of the Proposed Rules, under the caption "Determination by the Director," set forth DNREC's proposed procedure for determining whether there should be a freeze. *Nowhere in either section is the Commission even mentioned.* As shown in proposed Section 6.1 and 7.1, titled "Implementation" and "Lifting of a Freeze" respectively, the Proposed Rules relegate the Commission to helping DNREC get the word out if the Director – and s/he alone - decides that a freeze should be implemented, and when the freeze should be lifted. Only if the Director decides that a freeze should be implemented or lifted do the Proposed Rules allow the Commission any involvement.

This evisceration of the Commission's participation in the determination is completely contrary to the clear language of Sections 354(i) and (j). DNREC is bound by the language of the statutes; it cannot simply rewrite Sections 354(i) and (j) to suit itself:

> Legislation … may not be enacted under the guise of its exercise by adopting a rule or regulation which is out of harmony with, or which alters, extends or limits the Act, or which is inconsistent with clear legislative intent as therein expressed. Thus, as in the present case, where a right is granted to a class by statute, the agency administering such statute may not by the adoption and promulgation of a rule or regulation add to the condition of that right a condition not stated in the statute, nor may it exclude from that right a class of persons included within the terms of the statute.

Wilmington Country Club v. Delaware Liquor Commission, 91 A.2d 250, 255 (Del. Super. 1952).

The Commission is a "class of persons included within the terms of the statute." DNREC may not want to consult with the Commission regarding the determination of whether a freeze should be declared, but it is required to do so: DNREC cannot write that obligation out of the statute through its Proposed Rules. Therefore, Sections 5.2 and 5.3 must be rewritten to provide that the Commission is a necessary party to the determination of the declaration (or not) of the freeze provided for in Sections 354(i) and (j).

IV. Sections 5.4-5.8: Assuming *Arguendo* That DNREC Has the Authority to Promulgate Regulations to Implement 26 *Del. C.* §§354(i) and (j), Sections 5.4 – 5.8 Must Be Deleted.

A. DNREC Has No Authority to Amend the Statutes to Include the Factors That The Director Will Consider in Determining Whether to Declare a Freeze.

As discussed above, Sections 5.2 and 5.3 purport to give the Director sole authority to determine whether a freeze should be implemented. Even assuming *arguendo* that Sections 354(i) and (j) did give the Director this unfettered authority (which as we have shown above, they do *not*), Sections 5.4 through 5.8 of the Proposed Rules then go far beyond any authority those statutes give the Director regarding a freeze.

Under proposed Section 5.4, even if the Division of Energy & Climate's calculations show that the increase in the Solar/Renewable Energy Cost of Compliance hit their thresholds for implementation of a freeze, the Director is not bound by those calculations to implement a freeze. Instead, the Proposed Rules *then* state that in determining whether the Director should implement a freeze, s/he can consider four factors that appear *nowhere* in Sections 354(i) and (j). Those factors are: (1) the overall energy market conditions (whatever *that* means); (2) the avoided cost benefits from the RPS (whatever *those* are); (3) the externality benefits of changes in energy markets (whatever *that* means); and (4) the economic impacts of the deployment of renewable energy in Delaware (whatever those may be). As should be obvious, none of these factors is included in Sections 354(i) or (j). And DNREC cannot amend the statute by including them in the Proposed Rules.

In *Cartanza v. Delaware Department of Natural Resources and Environmental Control*, 2008 WL 4682653 (Del. Super Ct. Oct. 10, 2008), the Chancery Court found that DNREC was not permitted to set its own criteria by which SRA designations were to be made when the enabling statute specifically provided that authority to another body, and in so doing DNREC exceeded the authority delegated to it.

In *In the Matter of an Appeal of the Department of Natural Resources and Environmental* Control, 401 A.2d 93 (Del. Super Ct. 1978), the Superior Court found that the Secretary of DNREC could not:

> under the guise of his regulatory authority, foreclose the permit securing process and the application of the statutory criteria set forth in §6604. To hold otherwise would be to give the Secretary the power to prevent, permanently, any activity in a wetlands area simply through the designation process as opposed to the permit

process. An administrative agency may not adopt regulations which are inconsistent with the provisions of the enabling statute or out of harmony with, or extend the limits of, the Act which created it.

Id. at 96.

Similarly, in *Wilmington Country Club*, *supra* at 255, the Superior Court found that an agency administering a statute may not, by adoption of a rule or regulation, add to the condition of a statutorily-granted right a condition that was not expressly stated in the statute.

If the calculation of "Renewable Energy Cost of Compliance" (calculated according to the changed definitions identified in the first section of these Comments) hits the statutory 1%/3% thresholds, then the Director, in consultation with the Commission (as discussed in the second section of these Comments) must determine whether to implement a freeze or not. Neither the Director nor the Commission has been provided with the statutory authority to consider any *other* factors. We also note that neither Sen. McDowell, Rep. Williams, nor Secretary O'Mara identified or discussed even one of these factors during the Senate and House debates on the REPSA amendments; rather, all emphasized that the *statutory* provisions would act as a "circuit breaker" in the event that the costs of complying with the increased solar/eligible energy resources in Section 354(a) exceeded the statutory 1%/3% thresholds. In light of this, the DPA submits that proposed Sections 5.4 through 5.8 exceed the authority that the General Assembly provided to it in 26 *Del. C.* §§354(i) and (j).

B. Even if the Statutes Gave DNREC the Authority to Promulgate These Factors, The Proposed Rules Are Opaque as to What Will Inform the Director's Judgment With Respect to Them and Have a Serious Potential To Be Applied Arbitrarily and Capriciously.

Assuming that Sections 354(i) and (j) *did* give DNREC the authority to include conditions not found in the statute (which they do *not*), it is interesting to compare these factors with the three items that the General Assembly specifically required to be included in the total costs of compliance: the costs associated with any ratepayer funded state (solar) rebate program, REC/SREC purchases, and alternative compliance payments. What do these three things have in common? *They can all be easily ascertained.* We can ascertain the total amount associated with ratepayer-funded rebate programs (such as the Green Energy Fund). We can ascertain the cost to Delmarva of the REC/SREC purchases that it must make in a compliance year to meet the REPSA obligations. And we can ascertain how much was paid in alternative compliance payments. *These numbers are "objective benchmark[s]." See Gibson v. Sussex County Council*, 877 A.2d 54, 76 (Del. Ch. 2005).

But we *cannot* ascertain the amount of the factors set forth in proposed Rule 5.4. There are *no* "objective benchmarks." There is *no* source to which we can look to easily determine the exact cost of the overall market conditions. There is *no* source from which we can easily determine the exact cost of the avoided cost benefits from the RPS. There is *no* source to which we can look to easily determine the externality benefits of changes in energy markets. And there is *no* source from which we can easily determine the economic impacts of the deployment of renewable energy in Delaware. These costs will be whatever the Director, *in his sole discretion,* determines them to be.

Furthermore, the Proposed Rules are opaque with respect to what the Director *will* consider in determining any of the factors. By their very language, the Director is not limited to considering these factors. Proposed Sections 5.5 through 5.8 say only that the Director *may* consider them. S/he may also consider other unidentified factors. And we will not know which factors the Director considered because the Proposed Rules do not require the Director to publish the bases for her/his conclusion.

Finally, nothing in the Proposed Rules provides transparency as to what weight the Director will assign to each factor. Is it 25% per factor? Will one factor have more weight than another, and if so, which one? Will the application/weighting of the factors change depending on what compliance year is being considered? We have no idea, because the Proposed Rules don't tell us, and again, they don't require the Director to publish the bases for her/his conclusion.

The prior discussion demonstrates that the factors in proposed Sections 5.4 through 5.8 could be applied differently from year to year. Such different application would be arbitrary and capricious. *See, e.g., Gibson*, 877 A.2d at 76 n.78 (noting that restrictive covenants in a housing development are only upheld when they are "clear, precise and capable of even-handed application, and that such covenants are "suspect" due to their tendency "'to be arbitrary, capricious and therefore unreasonable'" (citing *Seabrook Homeowners Association, Inc. v. Gresser*, 517 A.2d 263, 268 (Del. Ch. 1968). The factors identified in the Proposed Rules are not clear, they are not precise, and they are capable of *uneven*-handed application.

In summary, in identifying factors that its Director will consider after finding that the 1%/3% thresholds have been met, DNREC has exceeded the authority that the General Assembly gave it. The statutes contain no such factors. Even if the General Assembly did give it the authority to consider these factors, there is no source from which anyone can independently verify the costs that DNREC will assign to them. Moreover, DNREC has provided no explanation of how it will apply the factors, the weight it will assign to each factor, or whether the application and/or weight of the factors will change from year to year. These sections must be removed from the Final Rules.

V. <u>CONCLUSION</u>

Based on the foregoing reasoning and authorities, the DPA submits that DNREC lacks the authority to promulgate the Proposed Rules. Assuming only for the sake of argument that DNREC does have such authority, then the following changes to the Proposed Rules are required:

(1) The definition of "Total Retail Costs of Electricity" must be changed to remove the reference to "transmission, distribution and delivery costs" in the calculation of that total cost. Alternatively, if transmission, distribution and delivery costs remain in the definition of

"Total Retail Costs of Electricity," then the "Renewable Energy Cost of Compliance" must be amended to include "transmission, distribution and delivery costs" to enable a fair comparison.

(2) Sections 5.2 and 5.3 must be amended to: (a) remove the reference to "the previous compliance year;" and (2) provide that the Commission will participate in the determination of whether a freeze should be implemented.

(3) Sections 5.4 through 5.8 must be removed because the legislation does not identify these criteria as a basis for either supporting or rejecting a freeze. In including them as considerations whether to implement a freeze or not when the statutory percentages would warrant a freeze, DNREC has exceeded the authority provided to it. Even if DNREC did have the authority to assess whether a freeze should be implemented after consideration of these factors, the Proposed Rules do not identify how it will apply the factors, the weight it will assign to each factor, or whether the application and/or weight of the factors will change from year to year, and therefore are not capable of clear, precise and even-handed application from year to year.

Respectfully submitted

/s/ Regina A. Iorii

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Counsel for the Delaware Division of the Public Advocate

Dated: February 16, 2015

Vest, Lisa A. (DNREC)

From:	Christie Pleger <cpleger85@gmail.com>
Sent:	Monday, February 16, 2015 3:25 PM
To:	Vest, Lisa A. (DNREC)
Subject:	Notes from Dale
Attachments:	Additional DSEC comments RPS Cost Cap Provisisons.pdf

Lisa,

Attached are the notes that Dale emailed this morning, we just realized that our server and email accounts are not working properly so this didn't make it to you when he sent it.

If you have any questions please send them to this email address and I will make sure he gets them.

Thank you!

Christie Pleger
CMI Solar& Electric, Inc.
Ph 302-731-5556
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DSEC

Delaware Solar Energy Coalition

Lisa Vest
Hearing Officer
DNREC
89 Kings Highway
Dover, DE 19901
Lisa.Vest@state.de.us
(302) 739-9042 fax

February 16, 2015

Re: Delaware Solar Energy Coalition (DSEC) additional comments on Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions

The Delaware Solar Energy Coalition (DSEC) is comprised of solar system owners, companies that install solar systems, manufacturers of solar equipment, and those with an interest in clean renewable energy. Delaware has built a roust industry around solar electrical, employing 500 hundred Delawareans, and creating over $400M in economic development in the past 5 years.

This boon to Delaware's economy is made possible by the Renewable Energy Portfolio Standard and DNRECs careful custodianship of the rules, regulations and programs controlling the adoption of solar power. DNRECs rulemaking on the Implementation of the Cost Cap provisions will control the future of solar power in Delaware, and determine if the economic and environmental benefits the people of Delaware enjoy due to renewable energy continue, or are sacrificed in the interests of protecting fossil fuel revenues.

DSEC submitted comments in January of 2014, and now offers the following additional comments in support of ensuring a viable future for solar and other renewable sources of power.

1. The cost cap should be calculated on a year to year basis.
    a. Delaware's RPS calls for 3.5% of the electricity statewide to be provided by solar power. If the cost cap was calculated on a cumulative basis, solar power would have to cost less than 1/3 of non renewable power. If that was indeed achievable, there would have been no need for an RPS.
    b. Standard power rates have been increasing on an average of 3% per year, even in light of declining fuel cost. The cost of solar power has been steadily and dramatically declining. To freeze that progress now would do a grave disservice to the ratepayers of Delaware who will see long term savings in electrical cost through meeting the RPS goals.

2. Data from the US Energy Information Agency (EIA) shows a direct correlation in consumer energy cost versus level of in-state power production.
    a. Delaware is an importer of electrify. It is a drain on the local economy to ship our power dollars to other states.
    b. Delaware has no reserves of Natural Gas, Coal or Petroleum. Any in-state power generated from those resources still contributes to a weakening of Delaware's economy.
    c. Between out of state electricity and fuel purchases, nearly a billion dollars a year are stripped from Delaware's economy.
    d. Under the RPS, solar power must be sited in Delaware. The revue and savings from renewable solar power stay in the local economy.

3. The cost of QFCP should not be included in the cost calculations
    a. QFCPs have their own cost caps specifically addressed and calculated in title 26.
    b. While QFCP's are enabled under legislation to provide an alternate method of meeting REC and SREC requirements, natural gas fired fuel cells are not qualified to produce either RECs or SRECs accumulated on PJM-Gats for retirement to satisfy REPS requirements.

c. QFCP provisions and implementation do not include the actual purchase and retirement of RECs or SRECs. Therefore they do not meet the criteria established for inclusion in cost cap calculations

4. Inclusion of externality calculations
   a. The IRP process has established substantial precedence to suggest that externalities should be considered in the calculation of the retail cost of energy and avoided cost rates.
   b. The IRP also clearly establishes the cost of said externalities.
   c. Such externalities that directly offset RPS costs to ratepayers should be included in cost calculations

5. Avoided Capacity costs
   a. Net metered Renewable Energy Systems provided a capacity value to the grid that is not realized by the system owner.
   b. Wind and Solar projects interconnected to the PJM grid are typically assigned a capacity value ranging from .3-.4 .
   c. The value of this capacity should be calculated as follows:

      (Name plate capacity of net metered systems by technology) X (Average PJM capacity factor by technology) X (average utility demand charge to end use customers)

      The resultant capacity savings should be and subtracted from the RPS compliance cost.

6. Long term Renewable energy costs
   a. Solar Renewable energy system costs do not escalate. Once the systems are paid for thorough initial savings, they continue to generate power throughout the life of equipment, typically measured in decades.
   b. Energy savings to renewable energy system owners should be considered as a reduction in compliance costs.

7. Reducing Volumetric Usage with Distributed Renewable Energy
   a. The installation of distributed renewable energy reduces the amount of power required to be supplied by the utility. This reduction lowers the requirement for SRECs and RECs for the life of the system. The cost savings represented by these volumetric reductions to REPS requirements should be included in the cost calculations.

8. Definitions of May vs. Shall
   a. The statue specifically uses the word "May" to give the Director discretion in determining that if the cost of REPS should exceed the cap, if the ongoing benefits outweigh those costs.
   b. The Director is further instructed to consult with the PSC prior to implementing a freeze, an action that would service no purpose if there was no discretion available to the Director.
   c. The stature then purposefully uses the word 'Shall" to indicate that once a freeze has been implemented, it "Shall" be lifted when the cost cap is no longer exceeded. The Director is specifically not given any discretion, and must lift a freeze once the costs have declined below the cap.
   d. The word "May" directly indicates the use of discretion, while "Shall" indicates a compulsory mandate. It is unreasonable to interpret these words as having an identical definition, particularly as they are used to indicate disparate levels of discretion in the statute.

Thank you for considering our comments.

Dale Davis
President
Delaware Solar Energy Coalition
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(302) 379-6572 cell

Vest, Lisa A. (DNREC)

From:	Maucher, Andrea (DOS)
Sent:	Monday, February 16, 2015 4:12 PM
To:	Vest, Lisa A. (DNREC)
Cc:	Bonar, David L (DOS); Price, Ruth A (DOS); Iorii, Regina (DOJ)
Subject:	RE: Comments on DNREC Proposed Cost Cap Rules
Attachments:	DPA formal comments on proposed Section 354 regulations_revised.pdf

Ms. Vest – Please replaced the prior version of the DPA's Comments with the attached which corrects minor typographical errors and includes the exhibit discussed in the comments. My apologies for any inconvenience.

Regards, Andrea

Andrea Maucher
Delaware Division of the Public Advocate
(302) 241-2545

From: Maucher, Andrea (DOS)
Sent: Monday, February 16, 2015 12:25 PM
To: Vest, Lisa A. (DNREC)
Cc: Bonar, David L (DOS); Price, Ruth A (DOS); Iorii, Regina (DOJ)
Subject: Comments on DNREC Proposed Cost Cap Rules

Dear Ms. Vest –

The Delaware Division of the Public Advocate hereby submits the attached comments regarding the Department of Natural Resources and Environmental Control's proposed rules Implementing 26 Del. C. §§354(i) and (j), as published in the December 1, 2014 Delaware Registrar of Regulations.

Regards,

Andrea B. Maucher
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COMMENTS OF THE DELAWARE DIVISION OF THE PUBLIC ADVOCATE ON THE PROPOSED RULES TO IMPLEMENT 26 *DEL. C.* §§354(i) AND (j) PROMULGATED BY THE DELAWARE DEPARTMENT OF NATURAL RESOURCES AND ENVIRONMENTAL CONTROL

The Delaware Division of the Public Advocate ("DPA") hereby submits the following comments ("Comments") regarding the Department of Natural Resources and Environmental Control's ("DNREC") proposed rules (the "Proposed Rules") Implementing 26 *Del. C.* §§354(i) and (j).

I. The Proposed Rules Are Void *Ab Initio* Because The Commission, Not DNREC, Has the Authority to Promulgate the Rules That Will Determine the Procedures for Freezing the RPS Requirements.

DNREC says that the authority supporting these regulations is 26 *Del. C.* §§354(i) and (j). And those sections do say that the Director, in consultation with the Commission, will determine whether a freeze should be imposed. But those sections do not give DNREC the authority to promulgate regulations to specify the procedures for freezing the RPS requirements, as DNREC apparently believes. Rather, in 26 *Del. C.* §362(b) (also part of the REPSA), the General Assembly expressly gave that authority to the *Public Service Commission:*

> For regulated utilities, the Commission shall further adopt rules and regulations *to specify the procedures for freezing the minimum cumulative solar photovoltaic requirement as authorized under § 354(i) and (j) of this title,* and for adjusting the alternative compliance payment and solar alternative compliance payment as authorized under § 358(d)(4) and (e)(3) of this title.

(Emphasis added). And Section 352(2) of the REPSA defines "Commission" as the Delaware Public Service Commission, not DNREC.

It could not be clearer that the *Commission*, not DNREC, is responsible for promulgating rules and regulations to specify the *procedures for the freeze* discussed in Sections 354(i) and (j).[1],[2] The statute does not give the Commission authority to delegate its responsibility for specifying the procedures for freezing the RPS requirements to DNREC, and the Commission cannot delegate its authority *sua sponte*. Since DNREC does not have the authority to specify the procedures for implementing a freeze, any regulations issued by it are void *ab initio* and unenforceable.

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[1]The DPA notes that Section 362(b) does not specifically identify "eligible energy resources" as subject to the Commission's regulation, but it *does* explicitly refer to both sections 354(i) and (j). And Section 354(j) addresses eligible energy resources. Therefore, the DPA concludes that the General Assembly did in fact include both types of renewable energy resources as subject to regulation by the Commission with respect to establishing procedures for freezing the RPS requirements.

[2] The Commission did issue regulations. *See* 26 *Del. Admin. C.* Part 3008 – Rules and Procedures to Implement the Renewable Energy Portfolio Standard. In Section 3.2.21 thereof, however, the Commission appears to delegate the responsibility for issuing procedures to implement 26 *Del. C.* §§354(i) and (j) to DNREC. This is impermissible.

II. Sections 2.0, 4.2, 4.3 and 4.4: Assuming *Arguendo* That DNREC Has the Authority to Promulgate Regulations to Implement 26 *Del. C.* §§354(i) and (j), The Proposed Rules' Definition of "Total Retail Costs of Electricity" Should Not Include the Costs of Transmission, Distribution or Delivery of Electricity – But If Those Functions Remain In the Definition, They Should Be Added to the Definition of "Renewable Energy Costs of Compliance" to Enable a Fair Comparison.

DNREC's proposed definition of "Total Retail Costs of Electricity" includes costs associated with the transmission, distribution and delivery of electricity. This is improper. Section 354 is concerned solely with *supply* of electricity, not with transmission, distribution or delivery of electricity. As a result of deregulation, those functions were unbundled. The "Total Retail Costs of Electricity" should include only those costs related to the supply function. The DPA prefers removing the transmission, distribution and delivery costs from the definition of "Total Retail Costs of Electricity." That definition could instead be called "Total Retail Costs of Electricity Supply." We submit that this change more accurately reflects the statutory language (which is limited to renewable energy mandates) and certainly is more consistent with the intent of the sponsors of the amendments to Section 354, who emphasized over and over again that the sections provided a "circuit breaker" to protect ratepayers in the event the renewable energy mandates became too expensive (defined by the General Assembly as the 1% increase for solar and 3% for eligible energy resources).

If DNREC is determined to include transmission, distribution and delivery costs in the "Total Retail Costs of Electricity," then transmission, distribution and delivery costs should also be included in the definition of "Renewable Energy Costs of Compliance" and in Sections 4.2 and 4.3 of the Proposed Rules. Since renewable energy also has to be transmitted, distributed and delivered, these costs are appropriately included in the definition *if* they are also included in the "Total Retail Costs of Electricity." Their inclusion would enable a true "apples to apples" comparison of "Renewable Energy Costs of Compliance" with "Total Retail Costs of Electricity" such that the only difference between the two would be the costs associated with the renewable energy mandates. Excluding transmission, distribution and delivery costs from the definition of "Renewable Energy Costs of Compliance" but including them in the definition of "Total Retail Costs of Electricity" will almost guarantee that the 1%/3% thresholds for implementing a freeze pursuant to the provisions of 26 *Del. C.* §§354(i) and (j) will never be reached.

III. Sections 5.2 and 5.3: Assuming *Arguendo* That DNREC Has the Authority to Promulgate Regulations to Implement 26 *Del. C.* §§354(i) and (j), DNREC Has Exceeded Such Authority Under 26 *Del. C.* §§354(i) and (j) By Adding the Language "Over the Previous Compliance Year" and By Writing the Commission Completely Out of the Determination of Whether to Implement a Freeze.

A. The Statutes Are Clear That the Appropriate Comparison Is the "Same Compliance Year," Not a Comparison of the Current Compliance Year to Some Earlier Compliance Year.

The rules of statutory construction are well settled. First, we must decide if the statute is ambiguous. A statute is ambiguous if it is susceptible of two reasonable

> interpretations or if a literal reading of its terms "would lead to an unreasonable or absurd result not contemplated by the legislature." If it is unambiguous, *then there is no room for judicial interpretation and "the plain meaning of the statute controls."* If, on the other hand, the statute is ambiguous, then we consider it as a whole and we read each section in light of the others to produce a harmonious whole. *Only when a statute is ambiguous do we look for guidance to its apparent purpose and place it as part of a broader statutory scheme. ...*

PHL Variable Insurance Co. v. Price Dawe 2006 Insurance Trust, 28 A.3d 1059, 1070 (Del. 2011) (internal quotation marks and sources omitted); *see also Taylor v. Diamond State Port Corp.*, 14 A.3d 536, 538 (Del. 2011); *Dewey Beach Enterprises, Inc. v. Board of Adjustment of the Town of Dewey Beach*, 1 A.3d 305, 307 (Del. 2010).

26 *Del. C.* §354(i) provides:

> The State Energy Coordinator in consultation with the Commission, may freeze the minimum cumulative solar photovoltaics requirement for regulated utilities if the Delaware Energy Office determines that the total cost of complying with this requirement *during a compliance year* exceeds 1% of the total retail cost of electricity for retail electricity suppliers *during the same compliance year*. In the event of a freeze, the minimum cumulative percentage from solar photovoltaics shall remain at the percentage for the year in which the freeze is instituted. The freeze shall be lifted upon a finding by the Coordinator, in consultation with the Commission, that the total cost of compliance can reasonably be expected to be under the 1% threshold. The total cost of compliance shall include the costs associated with any ratepayer funded state solar rebate program, SREC purchases, and solar alternative compliance payments.

(Emphasis added). 26 *Del C.* §354(j) similarly provides:

> The State Energy Coordinator in consultation with the Commission, may freeze the minimum cumulative eligible energy resources requirement for regulated utilities if the Delaware Energy Office determines that the total cost of complying with this requirement *during a compliance year* exceeds 3% of the total retail cost of electricity for retail electricity suppliers *during the same compliance year*. In the event of a freeze, the minimum cumulative percentage from eligible energy resources shall remain at the percentage for the year in which the freeze is instituted. The freeze shall be lifted upon a finding by the Coordinator, in consultation with the Commission, that the total cost of compliance can reasonably be expected to be under the 3% threshold. The total cost of compliance shall include the costs associated with any ratepayer funded state renewable energy rebate program, REC purchases, and alternative compliance payments.

(Emphasis added).

It could not be clearer that the General Assembly meant for the comparison to be between these items for *the same compliance year*. Apparently DNREC originally thought so too: in its first iteration of the Proposed Rules, Sections 5.2 and 5.3 stated that "If the Division calculations show that the (Solar)/Renewable Cost of Compliance is equal to or greater than 1%/3% of the Total Retail Cost, the Director shall determine whether a freeze should be implemented."

But somewhere between its first iteration of the Proposed Rules and the current one, DNREC apparently realized that interpreting the statutes exactly as they were written meant that it would have to consider implementing a freeze just about every year. The following table comes from Delmarva Power & Light Company's 2012 Integrated Resource Plan (which has been unsealed and is publicly available). The table shows that starting with Compliance Year 2013/14, the cost of complying with the requirements for renewable energy resources on an average customer's bill would exceed the 3% threshold of 26 *Del. C.* §354(j), and starting with compliance year 2017/18, the cost of complying with the requirements for solar renewable energy resources on a customer's bill would exceed the 1% threshold of 26 *Del. C.* §354(i).

Table 10

Impact of RPS Compliance on Typical Residential Customer Bills

Compliance Year	2013/14	2014/15	2015/16	2016/17	2017/18
Avg. Residential Customer Bill (1000 kW/Month)					
Supply Component	$89.32	$107.30	$120.30	$136.68	$151.65
Transmission Component	$6.72	$6.85	$6.99	$7.13	$7.34
Distribution Component	$30.30	$30.91	$31.53	$32.16	$33.14
Total	$125.97	$145.06	$158.82	$175.98	$192.13
Solar Compliance Impact on Typical Customer Bill					
Total SREC Compliance Cost per Avg Bill (1000 KW)	$0.91	$1.32	$2.19	$3.35	$5.27
SREC % Impact on Avg. Customer Bill	0.72%	0.91%	1.38%	1.90%	2.74%
RPS Compliance Impact on Typical Customer Bill					
Total RPS Compliance Cost per Avg Bill (1000 KW)	$6.60	$8.10	$9.18	$11.24	$15.15
	5.24%	5.58%	5.78%	6.39%	7.88%

(2012 Integrated Resource Plan at 102).

To avoid having to consider a freeze as soon as these rules become effective, the current iteration of the Proposed Rules now provides that the comparison will be made from one compliance year to the next, rather than within the same compliance year. The revised Sections 5.2 and 5.3 provide:

> If the Division calculations show that the increase in the (Solar) Renewable Energy Cost of Compliance *over the previous compliance year* is equal to or greater than 3% of the Total Retail Cost of Electricity, the Director shall determine whether a freeze should be implemented.

According to DNREC, its change of position is based on legal analysis it received from a Deputy Attorney General assigned to this matter. DNREC will not share the actual opinion from the deputy because it claims that it is protected by the attorney-client privilege, but it provided a "summary" of that advice at the January 7, 2015 public comment session. Here is what that summary said:

> The DAG reviewed the record in this proceeding and noted that commenters to the proposed rule questioned whether the cost cap provision refers to the total cost of compliance or the incremental or annual change in the cost of compliance. The DAG also noted that the language of this section of the statute could be construed as ambiguous, and as such, a reviewing court would look at the statute as a whole to understand the General Assembly's intent. A court would refer to Section 354(a), which sets forth the compliance schedule on a year-by-year basis through 2025. Interpreting the statute so that the minimum cumulative requirement refers to the cumulative increase from the beginning of the program would lead to an unreasonable or absurd result because at that rate the statutory compliance schedule could not be achieved, and that a court would not find that the General Assembly intended that result,. Therefore, the percentage caps refer to the statutory compliance schedule, which provides for year-over-year increases.

(Exhibit A).

This compares the wrong things. It is not whether the starting point should be the beginning of the program and the ending point should be the current compliance year. Rather, the statutory language clearly contemplates that the comparison is between the Total Retail Cost of Electricity and the total cost of complying with the RPS requirement *for the same compliance year*. There is nothing ambiguous about this, and the canons of statutory interpretation upon which DNREC relies to justify its reference to a different section of the statute do not come in play when a statute is clear on its face: "If [the statute] is unambiguous, *then there is no room for judicial interpretation and "the plain meaning of the statute controls.*" *PHL, supra; Taylor, supra; Dewey Beach Enterprises, supra.* (Emphasis added).

DNREC has not shared with anyone what language in the statutes leads it to conclude that the statutes are ambiguous. But they are not ambiguous. Had the General Assembly wanted to make the comparison between current costs and last year's costs, it certainly knew how to do so. But the General Assembly did not want that to be the comparison. It wanted the comparison to be between the total electricity costs and the RPS/solar compliance costs for the *same compliance year*.

In imposing a comparison of current compliance year costs to last year's compliance year's costs, DNREC has rewritten the statute. This is inappropriate. DNREC is bound by the language of the statutes; it cannot simply rewrite Sections 354(i) and (j) to suit itself or to reach a conclusion that is more palatable to it:

> Legislation ... may not be enacted under the guise of its exercise by adopting a rule or regulation which is out of harmony with, or which alters, extends or limits the Act, or which is inconsistent with clear legislative intent as therein expressed.

Wilmington Country Club v. Delaware Liquor Commission, 91 A.2d 250, 255 (Del. Super. 1952).

Therefore, Sections 5.2 and 5.3 of the Proposed Rules must be amended to remove the reference to "the previous compliance year."

B. The Proposed Regulations Ignore the Role of the Delaware Public Service Commission in Determining Whether a Freeze Should Be Implemented.

Both Sections 354(i) and (j) provide that the State Energy Coordinator (now the Director of the Division of Energy & Climate) "in *consultation with the Commission*" (that is, the Delaware Public Service Commission) may freeze the minimum cumulative solar photovoltaics/eligible energy resource requirements. (Emphasis added). These provisions clearly envision that the Commission *will* be involved in determining whether there should be a freeze in the first place.

Sections 5.2 and 5.3 of the Proposed Rules, under the caption "Determination by the Director," set forth DNREC's proposed procedure for determining whether there should be a freeze. *Nowhere in either section is the Commission even mentioned.* As shown in proposed Section 6.1 and 7.1, titled "Implementation" and "Lifting of a Freeze" respectively, the Proposed Rules relegate the Commission to helping DNREC get the word out if the Director – and s/he alone - decides that a freeze should be implemented, and when the freeze should be lifted. Only if the Director decides that a freeze should be implemented or lifted do the Proposed Rules allow the Commission any involvement.

This evisceration of the Commission's participation in the determination is completely contrary to the clear language of Sections 354(i) and (j). DNREC is bound by the language of the statutes; it cannot simply rewrite Sections 354(i) and (j) to suit itself:

> Legislation ... may not be enacted under the guise of its exercise by adopting a rule or regulation which is out of harmony with, or which alters, extends or limits the Act, or which is inconsistent with clear legislative intent as therein expressed. Thus, as in the present case, where a right is granted to a class by statute, the agency administering such statute may not by the adoption and promulgation of a rule or regulation add to the condition of that right a condition not stated in the statute, nor may it exclude from that right a class of persons included within the terms of the statute.

Wilmington Country Club v. Delaware Liquor Commission, 91 A.2d 250, 255 (Del. Super. 1952).

The Commission is a "class of persons included within the terms of the statute." DNREC may not want to consult with the Commission regarding the determination of whether a freeze should be declared, but it is required to do so: DNREC cannot write that obligation out of the statute through its Proposed Rules. Therefore, Sections 5.2 and 5.3 must be rewritten to provide that the Commission is a necessary party to the determination of the declaration (or not) of the freeze provided for in Sections 354(i) and (j).

IV. Sections 5.4-5.8: Assuming *Arguendo* That DNREC Has the Authority to Promulgate Regulations to Implement 26 *Del. C.* §§354(i) and (j), Sections 5.4 – 5.8 Must Be Deleted.

A. DNREC Has No Authority to Amend the Statutes to Include the Factors That The Director Will Consider in Determining Whether to Declare a Freeze.

As discussed above, Sections 5.2 and 5.3 purport to give the Director sole authority to determine whether a freeze should be implemented. Even assuming *arguendo* that Sections 354(i) and (j) did give the Director this unfettered authority (which as we have shown above, they do *not*), Sections 5.4 through 5.8 of the Proposed Rules then go far beyond any authority those statutes give the Director regarding a freeze.

Under proposed Section 5.4, even if the Division of Energy & Climate's calculations show that the increase in the Solar/Renewable Energy Cost of Compliance hit their thresholds for implementation of a freeze, the Director is not bound by those calculations to implement a freeze. Instead, the Proposed Rules *then* state that in determining whether the Director should implement a freeze, s/he can consider four factors that appear *nowhere* in Sections 354(i) and (j). Those factors are: (1) the overall energy market conditions (whatever *that* means); (2) the avoided cost benefits from the RPS (whatever *those* are); (3) the externality benefits of changes in energy markets (whatever *that* means); and (4) the economic impacts of the deployment of renewable energy in Delaware (whatever those may be). As should be obvious, none of these factors is included in Sections 354(i) or (j). And DNREC cannot amend the statute by including them in the Proposed Rules.

In *Cartanza v. Delaware Department of Natural Resources and Environmental Control*, 2008 WL 4682653 (Del. Super Ct. Oct. 10, 2008), the Chancery Court found that DNREC was not permitted to set its own criteria by which SRA designations were to be made when the enabling statute specifically provided that authority to another body, and in so doing DNREC exceeded the authority delegated to it.

In *In the Matter of an Appeal of the Department of Natural Resources and Environmental* Control, 401 A.2d 93 (Del. Super Ct. 1978), the Superior Court found that the Secretary of DNREC could not:

> under the guise of his regulatory authority, foreclose the permit securing process and the application of the statutory criteria set forth in §6604. To hold otherwise would be to give the Secretary the power to prevent, permanently, any activity in a wetlands area simply through the designation process as opposed to the permit

> process. An administrative agency may not adopt regulations which are inconsistent with the provisions of the enabling statute or out of harmony with, or extend the limits of, the Act which created it.

Id. at 96.

Similarly, in *Wilmington Country Club*, *supra* at 255, the Superior Court found that an agency administering a statute may not, by adoption of a rule or regulation, add to the condition of a statutorily-granted right a condition that was not expressly stated in the statute.

If the calculation of "Renewable Energy Cost of Compliance" (calculated according to the changed definitions identified in the first section of these Comments) hits the statutory 1%/3% thresholds, then the Director, in consultation with the Commission (as discussed in the second section of these Comments) must determine whether to implement a freeze or not. Neither the Director nor the Commission has been provided with the statutory authority to consider any *other* factors. We also note that neither Sen. McDowell, Rep. Williams, nor Secretary O'Mara identified or discussed even one of these factors during the Senate and House debates on the REPSA amendments; rather, all emphasized that the *statutory* provisions would act as a "circuit breaker" in the event that the costs of complying with the increased solar/eligible energy resources in Section 354(a) exceeded the statutory 1%/3% thresholds. In light of this, the DPA submits that proposed Sections 5.4 through 5.8 exceed the authority that the General Assembly provided to it in 26 *Del. C.* §§354(i) and (j).

B. Even if the Statutes Gave DNREC the Authority to Promulgate These Factors, The Proposed Rules Are Opaque as to What Will Inform the Director's Judgment With Respect to Them and Have a Serious Potential To Be Applied Arbitrarily and Capriciously.

Assuming that Sections 354(i) and (j) *did* give DNREC the authority to include conditions not found in the statute (which they do *not*), it is interesting to compare these factors with the three items that the General Assembly specifically required to be included in the total costs of compliance: the costs associated with any ratepayer funded state (solar) rebate program, REC/SREC purchases, and alternative compliance payments. What do these three things have in common? *They can all be easily ascertained.* We can ascertain the total amount associated with ratepayer-funded rebate programs (such as the Green Energy Fund). We can ascertain the cost to Delmarva of the REC/SREC purchases that it must make in a compliance year to meet the REPSA obligations. And we can ascertain how much was paid in alternative compliance payments. *These numbers are "objective benchmark[s]." See Gibson v. Sussex County Council*, 877 A.2d 54, 76 (Del. Ch. 2005).

But we *cannot* ascertain the amount of the factors set forth in proposed Rule 5.4. There are *no* "objective benchmarks." There is *no* source to which we can look to easily determine the exact cost of the overall market conditions. There is *no* source from which we can easily determine the exact cost of the avoided cost benefits from the RPS. There is *no* source to which we can look to easily determine the externality benefits of changes in energy markets. And there is *no* source from which we can easily determine the economic impacts of the deployment of renewable energy in Delaware. These costs will be whatever the Director, *in his sole discretion,* determines them to be.

Furthermore, the Proposed Rules are opaque with respect to what the Director *will* consider in determining any of the factors. By their very language, the Director is not limited to considering these factors. Proposed Sections 5.5 through 5.8 say only that the Director *may* consider them. S/he may also consider other unidentified factors. And we will not know which factors the Director considered because the Proposed Rules do not require the Director to publish the bases for her/his conclusion.

Finally, nothing in the Proposed Rules provides transparency as to what weight the Director will assign to each factor. Is it 25% per factor? Will one factor have more weight than another, and if so, which one? Will the application/weighting of the factors change depending on what compliance year is being considered? We have no idea, because the Proposed Rules don't tell us, and again, they don't require the Director to publish the bases for her/his conclusion.

The prior discussion demonstrates that the factors in proposed Sections 5.4 through 5.8 could be applied differently from year to year. Such different application would be arbitrary and capricious. *See, e.g., Gibson*, 877 A.2d at 76 n.78 (noting that restrictive covenants in a housing development are only upheld when they are "clear, precise and capable of even-handed application, and that such covenants are "suspect" due to their tendency "'to be arbitrary, capricious and therefore unreasonable'" (citing *Seabrook Homeowners Association, Inc. v. Gresser*, 517 A.2d 263, 268 (Del. Ch. 1968). The factors identified in the Proposed Rules are not clear, they are not precise, and they are capable of *uneven*-handed application.

In summary, in identifying factors that its Director will consider after finding that the 1%/3% thresholds have been met, DNREC has exceeded the authority that the General Assembly gave it. The statutes contain no such factors. Even if the General Assembly did give it the authority to consider these factors, there is no source from which anyone can independently verify the costs that DNREC will assign to them. Moreover, DNREC has provided no explanation of how it will apply the factors, the weight it will assign to each factor, or whether the application and/or weight of the factors will change from year to year. These sections must be removed from the Final Rules.

V. <u>CONCLUSION</u>

Based on the foregoing reasoning and authorities, the DPA submits that DNREC lacks the authority to promulgate the Proposed Rules. Assuming only for the sake of argument that DNREC does have such authority, then the following changes to the Proposed Rules are required:

(1) The definition of "Total Retail Costs of Electricity" must be changed to remove the reference to "transmission, distribution and delivery costs" in the calculation of that total cost. Alternatively, if transmission, distribution and delivery costs remain in the definition of

"Total Retail Costs of Electricity," then the "Renewable Energy Cost of Compliance" must be amended to include "transmission, distribution and delivery costs" to enable a fair comparison.

(2) Sections 5.2 and 5.3 must be amended to: (a) remove the reference to "the previous compliance year;" and (2) provide that the Commission will participate in the determination of whether a freeze should be implemented.

(3) Sections 5.4 through 5.8 must be removed because the legislation does not identify these criteria as a basis for either supporting or rejecting a freeze. In including them as considerations whether to implement a freeze or not when the statutory percentages would warrant a freeze, DNREC has exceeded the authority provided to it. Even if DNREC did have the authority to assess whether a freeze should be implemented after consideration of these factors, the Proposed Rules do not identify how it will apply the factors, the weight it will assign to each factor, or whether the application and/or weight of the factors will change from year to year, and therefore are not capable of clear, precise and even-handed application from year to year.

Respectfully submitted

/s/ Regina A. Iorii

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Counsel for the Delaware Division of the Public Advocate

Dated: February 16, 2015

Department of Natural resources and Environmental Control
Division of Energy & Climate

Summary of the legal review on whether the 3 percent and 1 percent cost caps in 26 *Del. C.* § 354 (i), (j) refer to a cumulative increase or year-over-year increase

January 7, 2015

The DNREC Division of Energy & Climate asked the Deputy Attorney General ("DAG") assigned to this matter whether the 3 percent and 1 percent caps in 26 *Del. C.* § 354 (i), (j) refer to a cumulative increase or year-over-year increase. The advice that the DAG provided to the Division is a confidential communication protected by the attorney-client privilege, and the Division is not required to produce that document. The Division has opted to provide the following summary of the legal review of this question with the understanding that ***by releasing this summary, the Division is not waiving the attorney-client privilege attached to this or any other legal advice in this matter.***

The DAG reviewed the record in this proceeding and noted that commenters to the proposed rule questioned whether the cost cap provision refers to the total cost of compliance or the incremental or annual change in the cost of compliance. The DAG also noted that the language of this section of the statute could be construed as ambiguous, and as such, a reviewing court would look at the statute as a whole to understand the General Assembly's intent. A court would refer to Section 354(a), which sets forth the compliance schedule on a year-by-year basis through 2025. Interpreting the statute so that the minimum cumulative requirement refers to the cumulative increase from the beginning of the program would lead to an unreasonable or absurd result because at that rate the statutory compliance schedule could not be achieved, and that a court would not find that the General Assembly intended that result. Therefore, the percentage caps refer to the statutory compliance schedule, which provides for year-over-year increases.

Vest, Lisa A. (DNREC)

From:	Logan Welde <lwelde@cleanair.org>
Sent:	Monday, February 16, 2015 5:15 PM
To:	Vest, Lisa A. (DNREC)
Cc:	Noyes, Thomas G. (DNREC)
Subject:	Clean Air Council comments on RPS cost cap
Attachments:	Clean Air Council comments on proposed RPS cost cap .pdf

Ms Vest,
Please see attached Clean Air Council's comments on DNREC's proposed implementation of RPS cost cap provisions.

Thanks,

Logan Welde
Staff Attorney
Clean Air Council
(215) 567-4004 (126)

Clean Air Council

February 16, 2015

Via Electronic Mail

Lisa Vest
Hearing Officer
Department of Natural Resources and Environmental Control
89 Kings Highway
Dover, DE 19901

Re: 102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions Comments on Proposed Rules to Implement 26 Del.C. §354(i) & (j), Register Notice SAN #2012-03

Dear Ms. Vest,

Clean Air Council ("Council") hereby submits the following comments in response to the proposed regulations on the "Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions" under 26 *Del. C.* § 354(i) & (j) (hereinafter "DNREC's proposal").

The Council is a member supported, non-profit environmental organization dedicated to protecting everyone's right to breathe clean air. The Council and its members are actively involved in the protection of air quality and recognize that energy generation and fossil fuel transportation are major contributors to air pollution in Delaware and states throughout the region, including Pennsylvania and New Jersey.

Background/Introduction:

On July 28, 2010 the Delaware General Assembly amended Title 26 of the Delaware Code relating to the Renewable Portfolio Standards ("RPS").[1] The General Assembly amended the legislation in order to "strengthen Delaware's Renewable Energy Portfolio Standards," "provide stability for the development of renewable energy markets in [Delaware]," "incentivize renewable energy projects," and "provide consumer protections," among other reasons.[2]

[1] 77 *Del. Laws, c.* 451, Formerly Senate Substitute No. 1 for Senate Bill 119 (*available at* *http://delcode.delaware.gov/sessionlaws/ga145/chp451.pdf*).
[2] *Id.* (Synopsis *available at* *http://www.legis.delaware.gov/LIS/lis145.nsf/vwLegislation/SS+1+for+SB+119/$file/legis.html?open*).

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www.facebook.com/cleanaircouncil
www.twitter.com/cleanaircouncil

On November 2, 2011, Mr. Gary Myers petitioned the Department of Natural Resources and Environmental Control ("DNREC") to initiate a rule-making under 29 *Del. C.* § 8053. Specifically, Mr. Myers requested that the "rules would describe how the Coordinator and Energy Office will interpret and implement duties imposed on them by 26 *Del. C.* § 354(i) & (j)."[3] Mr. Myers contends "several ambiguities exist in the wording and phraseology of subsections 354(i) & (j)."[4] Mr. Myers' proposal includes language that makes a freeze **mandatory** if the costs of compliance for the Solar Renewable Energy Credits ("SREC") or Renewable Energy Credits ("REC") are greater than the thresholds provided by law (1% and 3% respectively).[5]

Clean Air Council will limit its comment to the wording of § 354(i) & (j), as well as whether and what externalities should be considered by the State Energy Coordinator and the Commission when determining the compliance costs.

Comments:

1. Section 354(i) & (j) is not ambiguous regarding the State Energy Coordinator's discretion as to whether a freeze should be implemented or its duty to unfreeze the SREC and REC requirements.

While the Council does agree that there are some ambiguities in the language of § 354(i) & (j), the Council does not believe that there is any ambiguity in the duties imposed upon the State Energy Coordinator as to what actions should be taken to implement a freeze or to unfreeze the SREC and REC requirements. The General Assembly spoke clearly in this instance. The State Energy Coordinator "*may* freeze the . . . requirement . . . if the Delaware Energy Office determines that the total cost of complying with this requirement during a compliance year exceeds [1% or 3%] of the total retail cost of electricity for retail electricity suppliers during the same compliance year."[6] The section then delineates the duties the State Energy Coordinator must take in order to unfreeze the requirement, "[t]he freeze *shall* be lifted upon a finding . . . that the total cost of compliance can reasonably be expected to be under the [1% or 3%] threshold."[7]

Delaware's rules on statutory construction are clear,[8] and are in-line with the United States Supreme Court.[9] First, an adjudicator must determine if the words themselves are ambiguous.[10] If the language of the statute is clear then the plain language controls.[11]

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[3] Letter to Carolyn Snyder, Director, Division of Energy and Climate, DNREC, November 2, 2011 (hereinafter "Myers' Letter").
[4] *Id.*, § B. Need For Regulations.
[5] *Id.* Proposed Rules to Implement 26 *Del. C.* § 354(i) & (j) at 9.0 Freezes.
[6] 26 *Del. C.* § 354(i) & (j) (emphasis added).
[7] *Id.* (emphasis added).
[8] *Dewey Beach Ent., Inc. v. Board of Adjustment of Town of Dewey Beach*, 1 A.3d 305, 307 (Del. 2010).

In this case, there is no ambiguity in the statute. The General Assembly chose the words that it used very carefully. In the first instance, when authorizing the State Energy Coordinator with the power to freeze the requirement it used the permissive "may." May is defined by Black's Law Dictionary as "[i]s permitted to."[12] Although "may" is occasionally used as "synonymous with *shall* or *must*," that is mostly to match legislative intent, and "the primary legal sense" is the "permissive" or "discretionary" sense.[13]

It is clear that, in this instance, the General Assembly did not intend for "may" to be synonymous with "shall" due to the fact that the drafters used both "may" and "shall" in the same section (§354(i)), and then repeated that same wording in the next section (§354(j)). This demonstrates the General Assembly's intent that both words be used, and that they be used to mean two different things. Claiming that the General Assembly's intent was to use two different words in the same section, yet have them mean the exact same thing would lead to an absurd outcome. The intent of the General Assembly was to differentiate the actions imposed on the State Energy Coordinator: use discretion ("may"), and use no discretion ("shall") after the calculations were performed and the Commission was consulted.

In the first case, the intent was to allow discretion to the State Energy Coordinator in whether or not to enact a freeze. Even if the State Energy Coordinator determined that the total cost of compliance exceeded a set threshold, the agency still retained the discretion as to whether or not a freeze would be implemented. The only requirement, after calculating the cost of compliance, placed on the State Energy Coordinator was to consult with the Commission; but, the State Energy Coordinator was still granted the discretion, regardless of the costs, or of the Commissions' advice, to either freeze the SREC and REC requirements for a given year or allow them to stay in place.

In the second case, as to whether the requirements should be unfrozen, the State Energy Coordinator was directed by the General Assembly to lift the freeze when the State Energy Coordinator finds "that the total cost of compliance can reasonably be expected to be under the [1% or 3%] threshold." If the State Energy Coordinator determines this to be the case there is no discretion granted, the State Energy Coordinator must lift the freeze.

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9 *Consumer Product Safety Commission et al. v. GTE Sylvania, Inc. et al.*, 447 U.S. 102 (1980) ("the starting point for interpreting a statute is the language of the statute itself").
10 *Dewey Beach Ent.*, 1 A.3d at 307.
11 *Dir. of Revenue v. CNA Holdings, Inc.*, 818 A.2d 953, 957 (Del. 2003).
12 *Black's Law Dictionary* 993 (7th ed. 1999). Black's defines "shall" as "[h]as a duty to; more broadly, is required to." *Id.* at 1379.
13 *Id.*

Delaware law is clear on this matter. When a legislative body writes a clear sentence into law, that plain meaning shall control.[14] In this case the General Assembly used different words in both sections. The plain meaning (everyday usage) of "may" is permissive, and the plain meaning of "shall" is mandatory. There is a meaningful, substantive difference between "may" and "shall," and that the General Assembly used these words in the fashion it did matters and must be recognized.

The inquiry as to whether the State Energy Coordinator has discretion to implement the freeze (it does), and whether or not it has discretion to unfreeze the requirements (it does not) should stop here.

The Council agrees with DNREC's proposal in §5.0 "Determination by the Director," however the Council believes the wording in part 5.2 and 5.3 should be ". . . over the previous compliance year is *greater* than . . . ."[15] The Council agrees with DNREC's proposal in §7.0 "Lifting of a Freeze."

2. <u>Calculation of the costs of compliance.</u>

The Clean Air Council is in agreement with DNREC's proposal in §5.0 "Calculation of the Cost of Compliance."[16]

3. <u>Costs and benefits to consider in determining whether to freeze the SREC and REC requirements should include externalities such as air quality, public health, and other environmental impacts.</u>

The Clean Air Council is mostly in agreement with DNREC's proposal on "[e]xternality benefits."[17] However, the Council believes that the language should read "[e]xternality benefits of changes in energy markets *shall* include, *but not limited to*, externality savings in health and mortality costs and environmental impacts . . . ." The General Assembly was clear in passing this legislation that the policy of the state of Delaware was to increase the amount of renewable energy partly for environmental and health concerns. The General Assembly stated, in its "declaration of policy" that "[t]hese benefits [those attributed to electricity generated from renewable energy sources] include improved regional and local air quality [and] improved public health . . . ."[18]

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[14] *Dir. of Revenue*, 818 A.2d at 957.
[15] The Council believes the General Assembly only wanted the State Energy Coordinator to issue a freeze if the costs "exceed" the 1% or 3% threshold. *See* 26 *Del. C.* § 354(i) & (j).
[16] Department of Natural Resources and Environmental Control, *102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions, Proposed*, §4.0 (hereinafter "DNREC's proposal").
[17] DNREC's proposal at §5.7.
[18] 26 *Del. C. §351(b).*

As such, the Council believes that, when calculating the costs and benefits associated with the generation of renewable electricity (and the amount of non-renewable electricity supplanted), the State Energy Coordinator *must* include both environmental and health-based costs and benefits.

4. Conclusion.

The Clean Air Council appreciates the opportunity to comment on DNREC's proposal. The Council believes that the General Assembly was clear in drafting § 354(i) & (j) that the State Energy Coordinator was granted discretion in determining, after calculating the total costs of compliance and consulting with the Commission, whether or not a freeze on the renewable requirements is appropriate for Delaware. The Council also believes that the General Assembly did not grant this same discretion to the State Energy Coordinator in determining, after calculating the total costs of compliance and consulting with the Commission, whether or not to unfreeze the renewable requirements. Finally, the Council believes that the General Assembly was clear, when determining what costs and benefits should be included in this calculation, that both environmental and health impacts shall be included.

Sincerely,

Joseph Otis Minott, Esq.
Executive Director

Vest, Lisa A. (DNREC)

From: Noyes, Thomas G. (DNREC)
Sent: Monday, February 16, 2015 6:20 PM
To: Vest, Lisa A. (DNREC)
Subject: Fw: Public Hearing on RPS Cost Cap January 7 at 6:00
Attachments: MAREC Comments on DE Cost Cap Rules 2-16-15.pdf

Lisa, I am forwarding these comment from MAREC to you.

Thanks.

Tom

From: Bruce Burcat <marec.org@gmail.com>
Sent: Monday, February 16, 2015 5:44:46 PM
To: Noyes, Thomas G. (DNREC)
Subject: Re: Public Hearing on RPS Cost Cap January 7 at 6:00

Dear Mr. Noyes:

Attached is a copy of MAREC's comments on the proposed RPS cost cap regulations. I do not have Hearing Examiner Vest's email - - so if you could forward a copy to her I would greatly appreciate it. Thank you.

Sincerely,

Bruce Burcat

On Fri, Jan 2, 2015 at 2:17 PM, Noyes, Thomas G. (DNREC) <Thomas.Noyes@state.de.us> wrote:

Interested parties:

A public hearing on the Proposed Rules to Implement RPS Cost Cap Provisions, 26 Del. C. § 354(i) & (j), will be held on January 7, 2015 beginning at 6:00 p.m. in the Public Service Commission Hearing Room, Cannon Building, 861 Silver Lake Blvd., Dover, DE, 19904.

The revised proposed regulation was published in the Register of Regulations on December 1, 2014 (http://regulations.delaware.gov/register/december2014/index.shtml) and can be found at http://regulations.delaware.gov/register/december2014/proposed/18%20DE%20Reg%20432%2012-01-14.htm.

Draft rules were published on December 1, 2013. A hearing was held January 8, 2014. Subsequently, the Division of Energy & Climate sought additional legal review of some issues involved. One issue is whether the 3 percent and the 1 percent refer to the total cost or cumulative cost impact of RPS compliance or to the cost to

the customer of year-over-year changes in the cost of compliance. The Deputy Attorney General assigned to this matter advised that the statute provides for year-over-year increases. The proposed regulation has been rewritten to reflect this opinion. Since this represents a significant change in the proposed regulation, it has been reposted and a hearing has been scheduled for January 7.

Written comments will be accepted through Friday, January 23. If you have any questions, please feel free to contact me.

Tom Noyes

--
Bruce Burcat, Executive Director
Mid-Atlantic Renewable Energy Coalition
(302) 331-4639
marec.org@gmail.com

MARE C

MID-ATLANTIC RENEWABLE ENERGY COALITION

February 16, 2015

Via Electronic Mail
Lisa Vest, Hearing Officer
Department of Natural Resources and Environmental Control
89 Kings Highway
Dover, DE 19901

Re: *Comments of the Mid-Atlantic Renewable Energy Coalition on 102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions (Proposed Rules to Implement 26 Del. C. §354(i) & (j))*

Dear Hearing Officer Vest:

The Mid-Atlantic Renewable Energy Coalition ("MAREC") submits these comments on the proposed regulations to implement a Renewable Portfolio ("RPS") cost cap as directed in 26 Del. C. §354(i) and (j). We appreciate this opportunity to comment in this important matter.

MAREC is a nonprofit corporation that was formed to help advance the opportunities for renewable energy development primarily in the region where the Regional Transmission Organization, PJM Interconnection, LLC ("PJM"), operates. MAREC's footprint includes Delaware, Pennsylvania, Maryland, New Jersey, Ohio, Virginia, West Virginia, North Carolina, and the District of Columbia. MAREC's membership consists of wind developers, wind turbine manufacturers, service companies, nonprofit organizations and a transmission company dedicated to the growth of renewable energy technologies to boost economic development in the region, improve our environment and diversify our electric generation portfolio, thereby enhancing energy security. The primary areas of focus of MAREC are to work with state regulators to develop rules and supportive policies for renewable energy; provide education and expertise on the environmental sustainability of wind energy; and offer technical expertise and advice on integrating variable wind energy resources into the electric grid.

I. Background

As a result of the enactment of Senate Substitute No. 1 for Senate Bill No. 119 on July 28, 2010, Delaware's renewable portfolio standard ("RPS") was amended to increase and extend the compliance requirements of the RPS; provide incentives for renewable energy projects that employed Delaware workers and utilized locally manufactured products; and include a provision that could have the State Energy Coordinator in consultation with the Public Service Commission ("PSC" or "Commission") freeze the RPS solar compliance requirements if a 1% cost threshold is exceeded or freeze the non-solar RPS compliance requirements if a 3% cost threshold is met.

The Division of Energy and Climate ("Division") of the Department of Natural Resources and Environmental Control ("DNREC") published draft rules on December 1, 2013. A hearing was held January 8, 2014. Subsequently, the Division sought additional legal review of some issues involved. After receiving guidance on the outstanding issues from the Office of the Attorney General, the Division published revised proposed regulations on December 1, 2014, and provided for an additional comment period on the revised regulations. It should be noted that the "Director" of the Division fills the role of the Energy Coordinator in the draft rules.

For purpose of these comments MAREC will limit its discussion to the 3% cost threshold for non-solar RPS compliance. The key statutory section for the non-solar cost cap is now found in 26 Del. C. §354(j).

II. Discussion

We have reviewed the revised proposed regulation and believe to a large extent that it is consistent with the statutory authority provided in the enacting legislation. MAREC believes the cost cap should be applied without impeding the intent of the original RPS legislation, which mandates the procurement of a minimum level of renewable resources in the State's electricity supply portfolio for the purpose of achieving a number of important goals, such as: increased electric supply diversity, reduced price volatility, new economic development opportunities and improved air and health quality, among other stated benefits. 26 Del. C. §351(b). While MAREC generally supports the proposed draft regulations that have been revised, we do have the following comments on two key areas of the regulations concerning the calculation of the cost cap and the discretion provided to the Director on a decision on whether to impose a freeze of the RPS requirements in a particular year.

1. Costs associated with the Bloom fuel cells should not be included in the calculation of the cost of compliance.
2. The discretion provided to the Director in Section 5.0 of the draft rules is appropriate and entirely consistent with the discretionary language of 26 Del. C. §354(j) and the intent of the RPS laws.

1. Bloom Energy Costs for Compliance Should Not Be Utilized in the Calculation for Renewable Energy Cost of Compliance.

As discussed in MAREC's original comments on the draft regulations submitted on January 24, 2014, we strongly disagree with the inclusion of costs associated with the Bloom Energy projects as set forth in Section 4.2.4 of the current version of the draft regulations under consideration. MAREC believes there is no statutory authority for the Bloom Fuel cells to be included in the cost cap calculation. Because Bloom Energy offsets or associated RECs do not fall into the category of being considered attributes of an Eligible Energy Resource, as they are derived as a result of fuel cell technology utilizing natural gas (not "powered by renewable fuels"), these costs should not count toward the cost cap.

It is also evident that the Bloom Energy arrangement which resulted in special legislation to deal with this project (primarily for economic development purposes) was meant to be judged from a cost perspective on a different basis than envisioned by the cost cap provisions of the RPS law. In fact, 26 Del. C. §364(d)(1)c[1] placed a distinct cost cap restriction on the Bloom arrangement, which had to be met prior to Commission approval of this long-term arrangement. MAREC does not believe that it would be appropriate to consider the costs of the Bloom fuel cell offsets which had to meet a different cost cap regime at the outset than traditional renewable energy technologies costs must meet on an ongoing basis under 26 Del. C. §354(j).

2. MAREC Strongly Supports the Areas of Discretion Given to the Director of the Division of Energy & Climate in Determining Whether to Institute a Freeze on the RPS Program.

MAREC supports Section 5.4 in the proposed regulations which allows the Director to use discretion in freezing the RPS by considering the use of various market factors such as the overall energy market conditions, the avoided cost benefit from the RPS, the externality benefits of changes in the energy market, and the economic impacts of the deployment of renewable energy in Delaware. These factors are all reasonable and justifiable given the clear discretion provided in the cost cap legislation, which states as follows:

> The State Energy Coordinator in consultation with the Commission **may** freeze the minimum cumulative eligible energy resources requirement for regulated utilities if the Delaware Energy Office determines that the total cost of complying with this requirement during a compliance year exceeds 3% of the total retail cost of electricity for retail electricity suppliers during the same compliance year.[2] (Emphasis added).

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[1] 26 Del. C. §364(d)(1)c states that: "[t]he cost to customers of the commission-regulated electric company for each MWH of output produced by the project which, on a levelized basis at the time of Commission approval, does not exceed the highest cost source for combined energy, capacity and environmental attributes approved by the Commission for inclusion in the renewable portfolio of the commission-regulated electric company as of January 1, 2011."

[2] See 26 Del. C. §354(j).

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The fact that the General Assembly used the word "may" as opposed to the word "shall" in the above excerpt from the cost cap legislation makes it clear that there was the intention to provide the Director discretion on deciding whether the cost cap should be imposed upon the initial reaching of the 3% threshold. When taking a look at the use of the word "may" in the context of the sentence, it is even more evident that the intention here was to provide the Director with discretion. If this was meant to be a mandatory implementation of the freeze, then it makes no sense to have the provision for the freeze lead off with the decision-maker consulting with the Commission in conjunction with the use of the word "may" in the sentence. If the threshold was to be met and no discretion had been provided, as a commentator has previously argued, then there would be absolutely no need for the consultation with the Commission. The freeze would just be imposed after a calculation of the formula for imposing the freeze was performed indicating the threshold was reached. The language of the statute is just plainly inconsistent with such an interpretation.

As MAREC believes the Director should have discretion as to whether the freeze should be imposed when the 3% cost of compliance level is met, we think it is appropriate for the Director to consider various factors prior to determining if a freeze should be imposed, such as the factors contemplated in Section 5.4 of the current draft regulations. Certain benefits of renewable energy should be considered as part of the Director's assessment, including, but not limited to: externalities, like carbon reductions, economic development benefits of renewables, reductions in cost as a result of renewable energy participating in regional markets, etc. Having renewable energy make up an increasing portion of the State's energy portfolio provide significant benefits and importance to the State and its citizens.

The following are some of the reasons why it is important to value the benefits of renewable energy (specifically shown in the context of wind energy) for purposes of whether or not the Director would determine to impose a freeze under his or her discretionary authority. If these benefits were not considered, the State would risk losing significant ground in its effort to increase its energy portfolio with clean renewable energy resources.

Wind energy reduces the cost of producing electricity

Essentially, when wind bids into the market at little or no cost, because it has no associated fuel cost, it will displace higher cost electricity resources, which leads to a lower clearing price and lower costs to consumers. In February 2014, PJM Interconnection LLC ("PJM"), the independent operator of the 13-state electricity grid released a study, called the PJM Renewable Integration Study, which reviewed the scenario of renewable energy comprising 20 or 30 percent of the grid's electricity supply.[3] What PJM found is that wind energy produces massive reductions in electricity production costs and wholesale price. Obtaining 20% of PJM's electricity from wind energy reduces the overall cost of producing electricity by $9 billion annually (about 25% of the overall production costs of $37 billion), while 30% wind reduces production costs by $13 billion annually across the 20% and 30% scenarios, with the high offshore scenarios producing the largest wholesale price reductions of $21 billion.

[3] PJM Renewable Integration Study (PRIS) (conducted on PJM's behalf by GE Energy Management) 2014. http://www.pjm.com/~/media/committees-groups/committees/mic/20131028-impacts/20131028-pjm-renewable-integration-study.ashx

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Wind energy protects consumers by reducing the impact of electricity price spikes

During the extreme cold snap known as the "polar vortex" which occurred on January 6th and 7th, 2014, wind energy saved electricity users in the Mid-Atlantic and Great Lakes states at least $1 billion according to an American Wind Energy Association study of the event.[4] Power plant outages and gas price spikes during the polar vortex caused electricity prices to reach record levels in PJM. Because of high demand and low supply, electricity and natural gas prices rose to dozens of times their normal levels in many regions – especially in the Mid-Atlantic and Great Lakes region. The polar vortex served as a reminder that wind energy plays a critical role in diversifying the region's energy mix, while simultaneously improving energy reliability while reducing energy costs for consumers.

Wind energy reduces pollution

Pollution from fossil-fired plants such as sulfur dioxide, nitrogen oxides, and carbon dioxide can harm public health and the environment in a number of ways. Since wind energy is often used to displace the least efficient fossil-fired power plant, adding wind energy greatly reduces pollution. The 2014 PJM Renewable Integration Study, which modeled up to 30% of energy in PJM being produced by solar and wind resources, found that although the values varied based on total penetration and the type of renewable generation added, on average 36% of the delivered renewable energy displaced PJM coal fired generation.[2] In addition, a 2013 Synapse Energy Economics study found that under additional wind resource scenarios, consumers in PJM will see significantly improved emissions profiles.[5]

Wind energy hedges against fuel price volatility

Wind energy and certain other renewable resources, like solar energy, are just a couple of the few resources that offer fuel price stability that can be locked in up front over a long-term, as their fuel costs will always be zero. Whereas, traditional fuels, like coal and natural gas prices are not stable and cannot be predicted over a long-term and could be especially influenced by short-term events. As discussed above, during the 2014 polar vortex natural gas prices surged – which in turn significantly increased electricity prices across PJM, wind prices bid into the PJM market and was able to replace some the most exorbitantly priced energy resources also bidding into the same markets at the same time -- saving consumers from even higher costs .

Wind energy has been shown that it can suppress electricity prices in the PJM region

Specifically, with respect to the Director's discretion in Section 5.4.2 as furthered defined in Section 5.6, there are a number of studies outlining the price reducing impacts of renewable energy when it participates in the wholesale energy market like PJM's.

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[4] American Wind Energy Association "Wind Energy Saves Consumers Money during the Polar Vortex" January 2015. http://awea.files.cms-plus.com/AWEA%20Cold%20Snap%20Report%20Final%20-%20January%202015.pdf

[5] Synapse Energy Economics, Inc. "The Net Benefits of Increased Wind Power in PJM" 2013. http://www.synapse-energy.com/Downloads/SynapseReport.2013-05.EFC.Increased-Wind-Power-in-PJM.12-062.pdf

Specific to this region, there have been several PJM specific studies performed which evaluate the price suppression effects of wind resources. In 2013, Synapse Energy Economics, Inc. found that that doubling the use of wind energy in PJM beyond existing requirements would decrease consumer electric bills by $6.9 billion per year on net. The additional wind would reduce the cost of operating the power system by $14.5 billion per year, for an upfront cost of only $7.6 billion per year, yielding $6.9 billion per year in net benefits for consumers. The economic benefits of increased wind energy use outweigh the costs by a factor of almost 2 to 1 according to the Synapse study.[6]

In 2009, PJM studied the impact of adding up to 15,000 MWs of wind energy to the PJM grid. The study found the addition of 15,000 MWs of wind to the PJM grid would decrease wholesale electricity prices (LMPs) by between $5 to $5.50 per MWh and the wholesale cost of power in the aggregate by between $4 to $4.5 billion. As a result, electricity customers' monthly bills would decrease by $3.50 to $4 per month or by $42 to $48 annually.[7]

III. Conclusion

MAREC generally supports the proposed revised regulations. However, MAREC respectfully requests that the final regulations be established without Sections 4.24 and 4.34, the provisions that would add the cost of Bloom fuel cells to the cost of renewables in a particular year for the purpose of calculating the threshold for freezing the compliance requirements for the RPS.

MAREC appreciates this opportunity to comment on the proposed revised regulations that are required to implement the renewable energy portfolio cost cap provisions.

Sincerely,

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[6] Synapse Energy Economics, Inc. "The Net Benefits of Increased Wind Power in PJM" 2013. http://www.synapse-energy.com/Downloads/SynapseReport.2013-05.EFC.Increased-Wind-Power-in-PJM.12-062.pdf

[7] PJM, "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market," 2009. http://www.pjm.com/~/media/documents/reports/20090127-carbon-emissions-whitepaper.ashx