

# Ohio Renewable Portfolio Standard

## #1: Enactment details, when were they enacted? Have they been repealed, have they expanded? Are other states looking to add program?

As shown in green in the map below, 20 states plus the District of Columbia currently have RPS policies in place. In addition, less-binding renewable energy “goals” have been established in Minnesota (for all utilities except Xcel Energy, which faces a mandatory standard), Illinois, and Vermont. In aggregate, these policies cover roughly 40% of total U.S. load. Other states in which an RPS is being considered (though some of these states are very early in the process) include (at a minimum) Idaho, Illinois, Indiana, Michigan, New Hampshire, North Carolina, Ohio, Virginia, and Washington (these states are shaded in gold on the map).

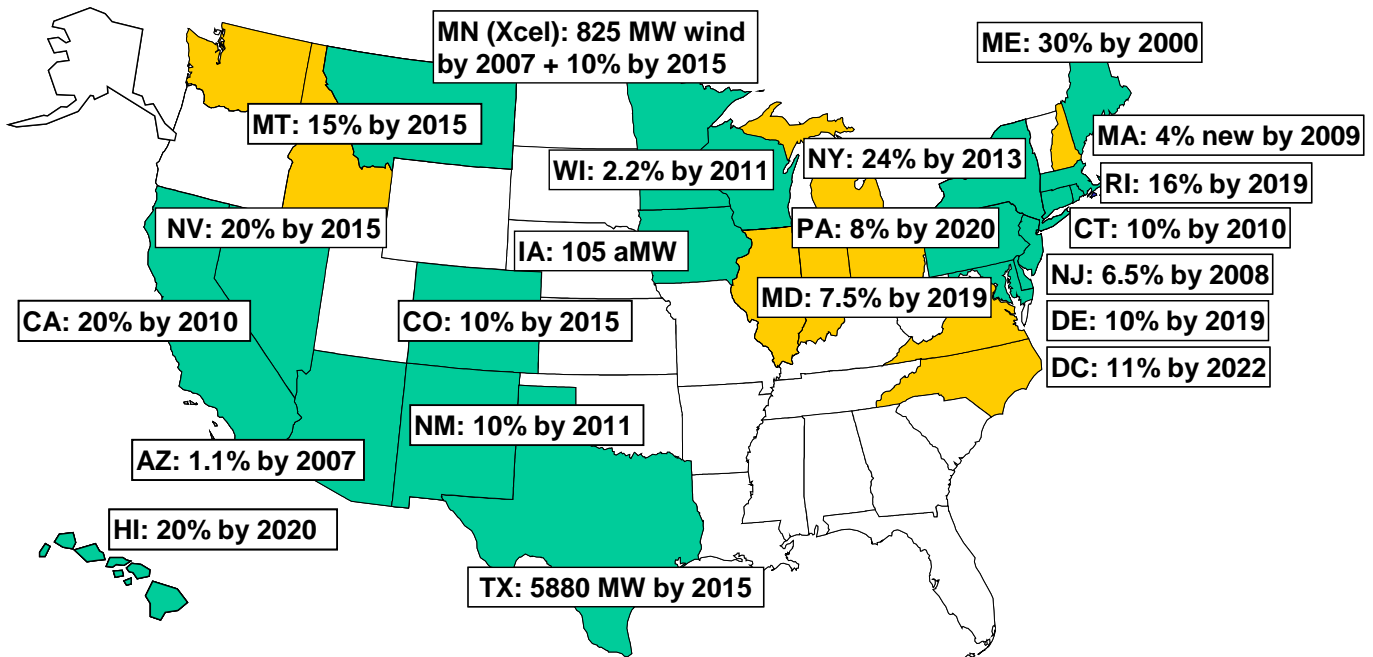


Figure 1. Map of State RPS Activity

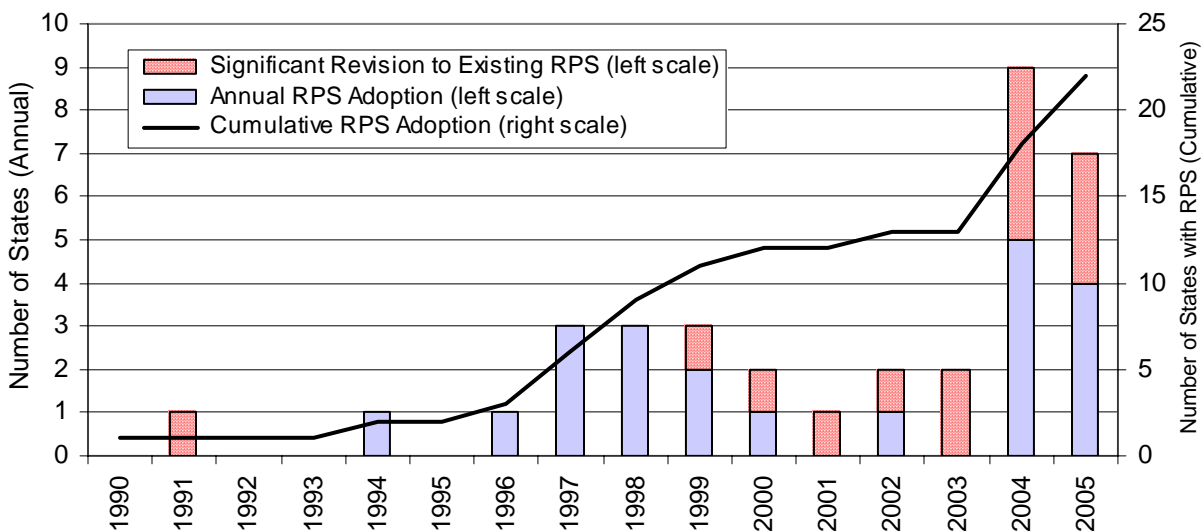
The remaining 20 states that are not currently pursuing an RPS (i.e., with the exception of Vermont,<sup>1</sup> all of the un-shaded states on the map) can, in most cases, attribute their inaction to one or more of the following factors:

- small electrical loads (applying an RPS in these instances will have little effect)
- relatively few low-cost renewable resources (perceived as a barrier especially in the Southeast)
- few or no in-state advocacy groups promoting an RPS
- general belief that other policies to support renewable are more appropriate

<sup>1</sup> If Vermont’s renewable energy goals are not achieved by 2012, the state’s utilities will become subject to a mandatory RPS in 2013.

- in-state utilities that actively oppose an RPS (perhaps due to first two factors)
- state politicians that do not favor an RPS (perhaps due to first five factors)

Figure 2 shows a timeline of RPS adoption and revisions over time. Historically, RPS policies were often packaged with restructuring legislation as a way to ensure that renewables would not be shut out of competitive markets. So, as shown here by the blue bars, a rash of states enacted RPS policies during the restructuring boom of the mid-to-late 90's. New RPS activity died down considerably following the electricity crisis of 2000/2001, but now appears to be gathering steam again, with 9 states having enacted new RPS policies in the last two years alone. And perhaps just as importantly, the red-shaded bars show that many states have been making significant revisions to their RPS policies, typically with the intent of correcting design flaws or simply strengthening the standard. At least three more major revisions – in AZ, NJ, and WI – are



expected in 2006, with others – in CA, ME, MN – also possible.

**Figure 2. Timeline of State RPS Implementation and Revision**

Table 1 shows implementation and major revision dates by state (the table does not identify more minor revisions). Though a few of the revisions listed here have been primarily process-oriented (e.g., aimed at facilitating compliance through the use of renewable energy certificates – RECs) most have been aimed either at correcting design flaws that have been identified (with the intent of making the existing standard stronger), or at expanding the size or scope of the standard. No state has yet to establish an RPS, and then subsequently repeal it. There have only been a smaller number of instances in which a revision was intended to weaken an existing standard.

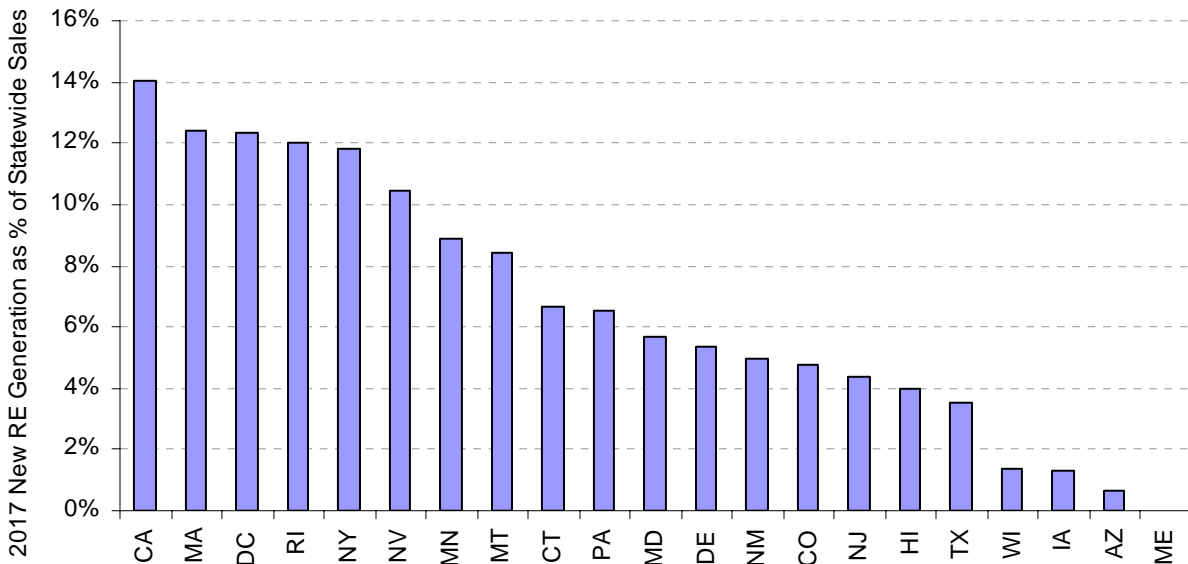
**Table 1. Implementation Timeline for State RPS Policies**

State	Date of RPS Enactment	Date of Major RPS Revisions (if any)	Treatment of Publicly Owned Utilities		
			Fully Exempt	Fully Obligated	Intermediate Treatment
AZ	1996	Apr. 2000			✓
CA	Sept. 2002	2004			✓
CO	Nov. 2004	N/A			✓
CT	Apr. 1998	June 2003, 2005	✓		
DC	Apr. 2005	N/A	N/A*	N/A*	N/A*
DE	July 2005	N/A			✓
HI	June 2001	June 2004		✓	
IA	1983	1991	✓		
IL	July 2005	N/A	✓		
MA	Nov. 1997	April 2002	✓		
MD	May 2004	N/A			✓
ME	May 1997	Sept. 1999, June 2003	✓		
MN	1994	2001, May 2003			✓
MT	April 2005	N/A			✓
NJ	Feb. 1999	May 2004, 2006 (pending)	✓		
NM	2000	Dec. 2002, Mar. 2004			✓
NV	1997	June 2001, Nov. 2002, 2003, 2005	✓		
NY	Sep. 2004	N/A	✓		
PA	1998	Nov. 2004			✓
RI	July 2004	N/A	✓		
TX	May 1999	2005			✓
WI	April 1998	Oct. 1999		✓	

\* There are no publicly owned utilities serving the District of Columbia.

Table 1 also shows the treatment of publicly owned utilities (POUs – e.g., municipal utilities and electric cooperatives) under state RPS policies. Nine states fully exempt POUs, two fully obligate them, and ten take an intermediate stance (e.g., only obligating those POUs engaged in retail competition; or granting certain POUs exemptions based on various factors, including utility size, or presence of a green pricing program).

Finally, Figure 3 shows the amount of new renewable generation projected by 2017 in each state, as a percentage of projected statewide retail sales. Data for this graphic come from the Union of Concerned Scientists. As suggested by the graphic, few states require increases in renewable generation as a percentage of load that exceed 1% a year.



**Figure 3. New Renewable Generation as a Percentage of Projected Sales in 2017**

## #2: How are states meeting requirements, how much capacity has been built, etc.?

Many state RPS policies are just now being implemented, and few states have more than a couple years of experience. In a number of states, RPS policies have been fully met or almost fully met each year. To our knowledge, annual RPS compliance has in fact been regularly achieved in all but four states: Arizona, California, Massachusetts, and Nevada. These four states have been under-complying for a number of reasons:

- **Arizona:** Utilities are not subject to automatic penalties under Arizona’s RPS, and the largely solar standard is only binding if there are enough funds collected from ratepayers through dedicated charges to help fund the requisite renewable energy purchases. Fund collection (which is established by the regulatory commission) has so far been insufficient to achieve full compliance with the percentage targets.
- **California:** In part due to policy complexity, there have been implementation and procurement delays. It also takes time for new renewable energy projects to come on line, so contracts are not turning into operating projects as rapidly as was hoped. Transmission bottlenecks are also problematic.
- **Massachusetts:** Incumbent utilities are now “wires-only” companies with little interest in signing long-term contracts with renewable generators, and competitive electricity

providers are not stable or creditworthy enough to easily support such contracts. Siting difficulties and permitting hurdles abound. As a result, new renewable generation has not come on line as rapidly as necessary to meet the targets. Compliance has therefore been achieved in significant part through alternative compliance payments.

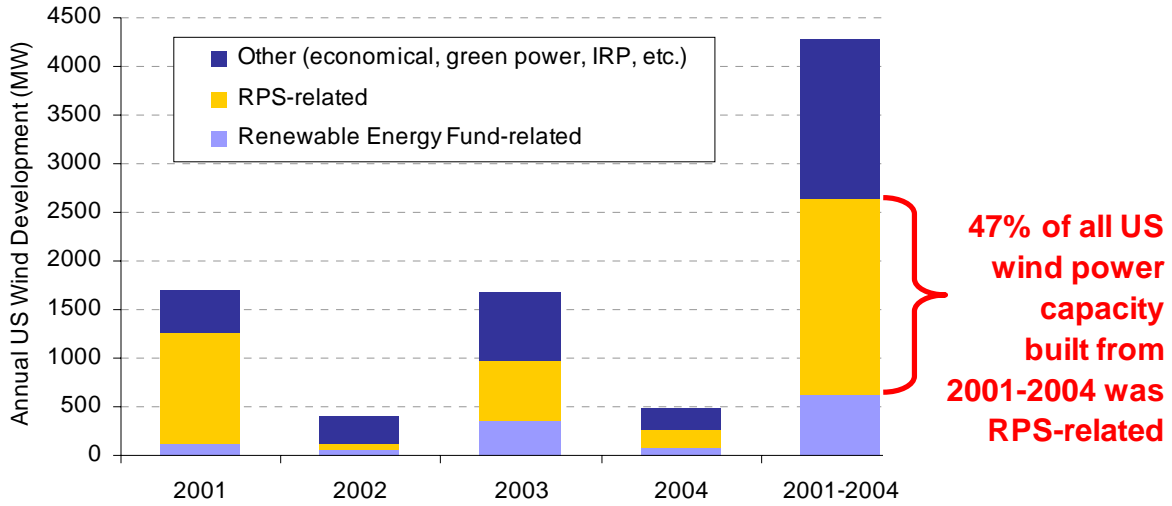
- **Nevada:** The state's two major investor-owned utilities have experienced financial difficulties and have not been sufficiently creditworthy to support finance-able long-term contracts with renewable generators. In part as a result, and in part because of other contracting difficulties, many of the long-term contracts that have been signed have resulted in delayed or failed projects.

Other states have largely been complying with RPS requirements (though again, note that in many states the RPS policies are just getting underway), leading to the construction of thousands of megawatts of new renewables capacity in the US over the past five years. For example, a 2004 report from the Energy Information Administration (EIA) found that "requirements or goals for new renewable energy capacity in 15 States had resulted in an estimated **2,335 megawatts** of new renewable electricity supply by the end of 2003. Most of the new capacity is fueled by wind power (2,183 megawatts), with smaller amounts of landfill gas, hydroelectricity, biomass, and solar photovoltaic technologies."<sup>2</sup> Texas accounted for the majority of that capacity (1,186 MW), followed by Minnesota (501 MW), Iowa (260 MW), California (201 MW), Wisconsin (154 MW), Arizona (14 MW), Pennsylvania (10 MW), and Massachusetts (9 MW).

A more recent LBNL analysis focused exclusively on wind power shows that nearly half of all wind power capacity built in the US from 2001 through 2004 was due, at least in part, to a state RPS. As shown in Figure 4, this amounts to more than 2,000 MW of new wind development over this 4-year period. Though not shown in Figure 4, this trend has continued into 2005: very preliminary estimates suggest that at least 1,100 MW of new wind power capacity coming on line in 2005 (in TX, NY, NM, MN, CA, PA, and NJ) was driven by RPS requirements. This amount is nearly half the total amount of new wind power capacity that AWEA expects to have been built in 2005.

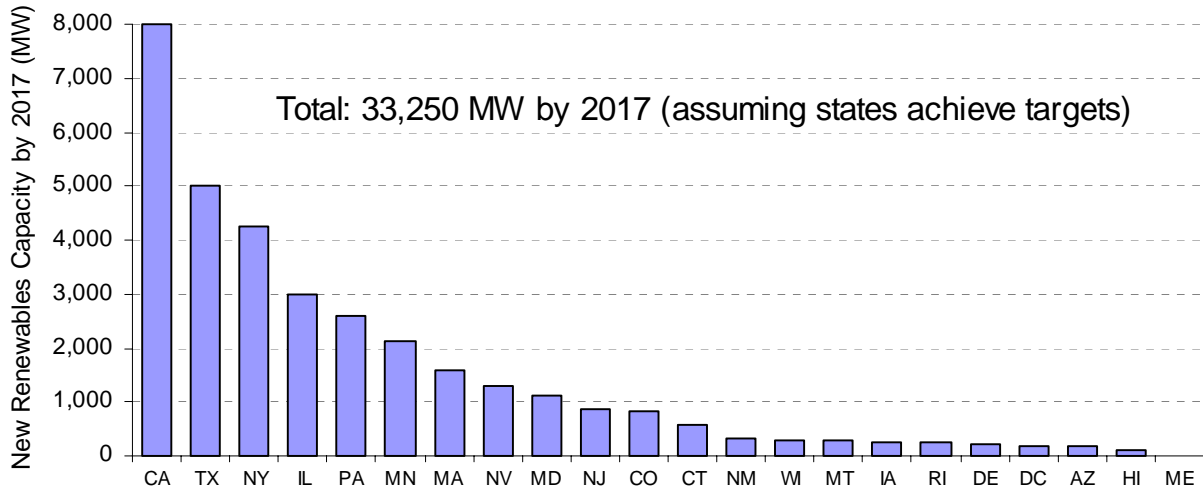
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<sup>2</sup> Petersik, Thomas. 2004. "State Renewable Energy Requirements and Goals: Status through 2003." Energy Information Administration. <http://www.eia.doe.gov/oiaf/analysispaper/rps/index.html>



**Figure 4. Drivers of New Wind Development in the United States, 2001-2004**

Finally, assuming that all states achieve their RPS targets (an admittedly overly aggressive assumptions), Figure 5 projects that more than 33,000 MW of new renewables capacity will be required by 2017 in order to meet RPS requirements.



Sources: Union of Concerned Scientists, California Energy Commission

**Figure 5. Projected New RPS-Driven Renewables Capacity by 2017**

### **#3: What are cost impacts on industrial users, as well as commercial? Are impacts on industrial customers higher than those on residential customers percentage wise since the former have lower rates from the utility?**

State RPS cost recovery details vary by state, and depend in part on whether the state allows retail competition. Where retail competition is allowed, competitive electricity retailers will recover costs as they see fit from customers. Because (with some exceptions – e.g., New York, Arizona, and California) there are not typically explicitly defined RPS “surcharges” that are visible on electricity bills, it is impossible to know how these competitive retailers are recovering costs from different customer classes. Similarly, we did not have the time to investigate how still-regulated providers are recovering costs by customer class.

Despite these caveats, we suspect that in most states RPS-related costs are recovered on an approximately equal cents/kWh basis from all customers and all customer classes. Though cost recovery of this form is non-discriminatory, because industrial rates are typically lower than residential rates, it does mean that industrial customers may see larger percentage increases in their electricity rates and bills than will residential customers.

To investigate the potential magnitude of these rate impacts, we review the projected rate impacts from a large number of state RPS cost-impact studies (see Figure 6). With few exceptions, these analyses of projected state RPS cost impacts project that the retail rate impacts of such policies will be relatively modest. However, as noted above, RPS rate impacts may have proportionally larger percentage effects on commercial and particularly industrial customers than residential ones, since the former group typically pays lower baseline electricity rates. Any cost premium of an RPS policy is primarily driven by increased electricity generation costs, and higher electricity generation costs affect industrial customers to a greater degree in percentage terms than residential customers, for whom generation costs generally represent a smaller portion of overall retail rates. Though all customer classes will likely experience very similar rate impacts in absolute cents per kilowatt-hour (kWh) terms, those same impacts measured in percentage terms will vary according to the differential between residential and industrial electricity rates.

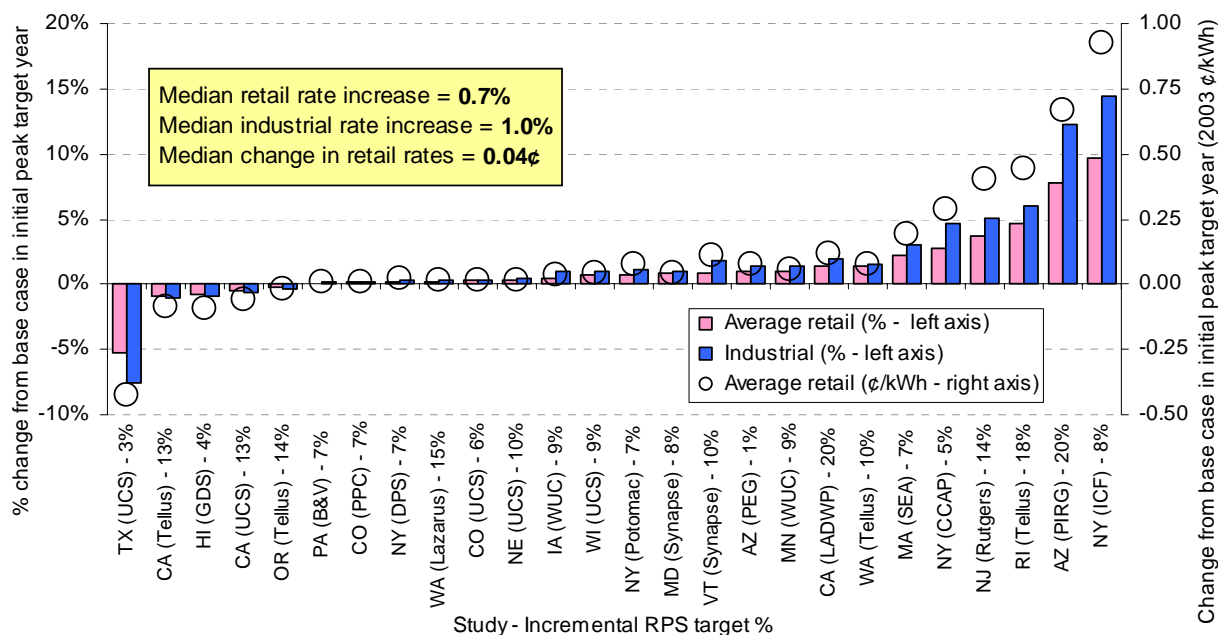
Figure 6 presents the projected rate impacts of RPS policies in 16 distinct states, as modeled by 25 different cost studies.<sup>3</sup> To illustrate the potential for different impacts on residential and industrial customers in percentage terms, we allocate RPS cost impacts equally to all customer classes in cents/kWh terms. As a result, industrial rate impacts (as measured in percent change) in the figure are on average about 40% higher than their residential counterparts.<sup>4</sup> More generally, several studies show expected rate savings, with a number of additional studies showing relatively modest rate increases (well below 5%). A small number of studies show more

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<sup>3</sup> Both Figure 6 and Figure 7 show cost results from the first year in which each modeled RPS policy reaches its peak target level. For example, data from the Massachusetts study is taken from 2012 – the year in which that state’s RPS first reaches its peak target level of 7%. This approach is intended to provide a proxy for the long-run rate impacts of each RPS policy, and to facilitate comparability among RPS policies that have different timeframes.

<sup>4</sup> Because of our method of allocating cost impacts, 40% is also the average difference between retail rates for residential and industrial customers.

significant (> 5%) rate impacts. Note that this figure focuses on rate impacts in the year in which the RPS percentage target reaches its maximum value.



**Figure 6. Projected RPS Electricity Rate Impacts by RPS Cost Study**

A number of states, in implementing RPS policies, have developed methods to cap the maximum cost of their RPS policy. These caps vary in their design, and include: (1) alternative compliance payments that limit the cost impact of the RPS, (2) caps on the maximum retail rate or bill impacts of the RPS, (3) caps on the power purchase contract price for renewable energy, and (4) caps on the amount of funds collected to cover the above-market cost of renewable energy. In addition to these overall cost caps, some states have specifically developed ways to limit the potential rate impacts for industrial customers:

- **Maryland:** Industrial process loads of over 300,000 MWh/yr are exempt from the RPS altogether. Additionally, smaller industrial process loads face a smaller penalty in the event of RPS non-compliance than do other customers, providing a lower cap to the cost of the RPS.
- **New Mexico:** RPS levels may be reduced for nongovernmental customers that consume over 10 million kWh at a single location so that the additional costs of renewables are less than 1% of annual electric charges or \$49,000. This level rises by 0.2% or \$10,000 per year to 2011, when additional charges for these customers for RPS compliance are fixed at the lower of 2% or \$99,000.
- **Delaware:** Retail sales on which the RPS applies excludes customers with a peak load of over 1500 kW.

**#4: What would the rate increase/decrease of electricity be in Ohio if 5, 10, or 15% by 2016 RPS or 20% by 2021 RPS was enacted?**

The incremental cost of an RPS policy is dependent on several factors, including the renewable resource potential of the state and/or region, the cost of accessing that potential, the projected cost of conventional generation, RPS design features, and many other factors. We had neither the budget nor time to conduct such a detailed assessment. Without performing a detailed cost impact analysis, it is difficult to accurately predict the rate impacts of a hypothetical Ohio RPS. However, we can consider the experience of existing state RPS policies and the projections of numerous other RPS analyses to produce a simple first-order approximation of the *potential* rate impact of an Ohio RPS.

In the context of an RPS, the price of renewable energy certificates (RECs) can represent the incremental cost of a unit of RPS-eligible renewable energy. In states with liquid compliance REC markets, REC prices range from a low of \$0.30 per megawatt-hour (MWh) in Maine to a high of \$54/MWh in Massachusetts (see Table 2; these values correspond to a REC price of 0.03 cents/kWh in Maine and 5.4 cents/kWh in Massachusetts). A large existing renewable resource base in Maine (whose RPS allows for the participation of existing resources) has resulted in very low REC prices, while a shortage of near-term qualifying renewable capacity in New England has driven up REC prices in Massachusetts. A well-designed RPS in Ohio would likely see much more moderate REC prices than those seem in Massachusetts.

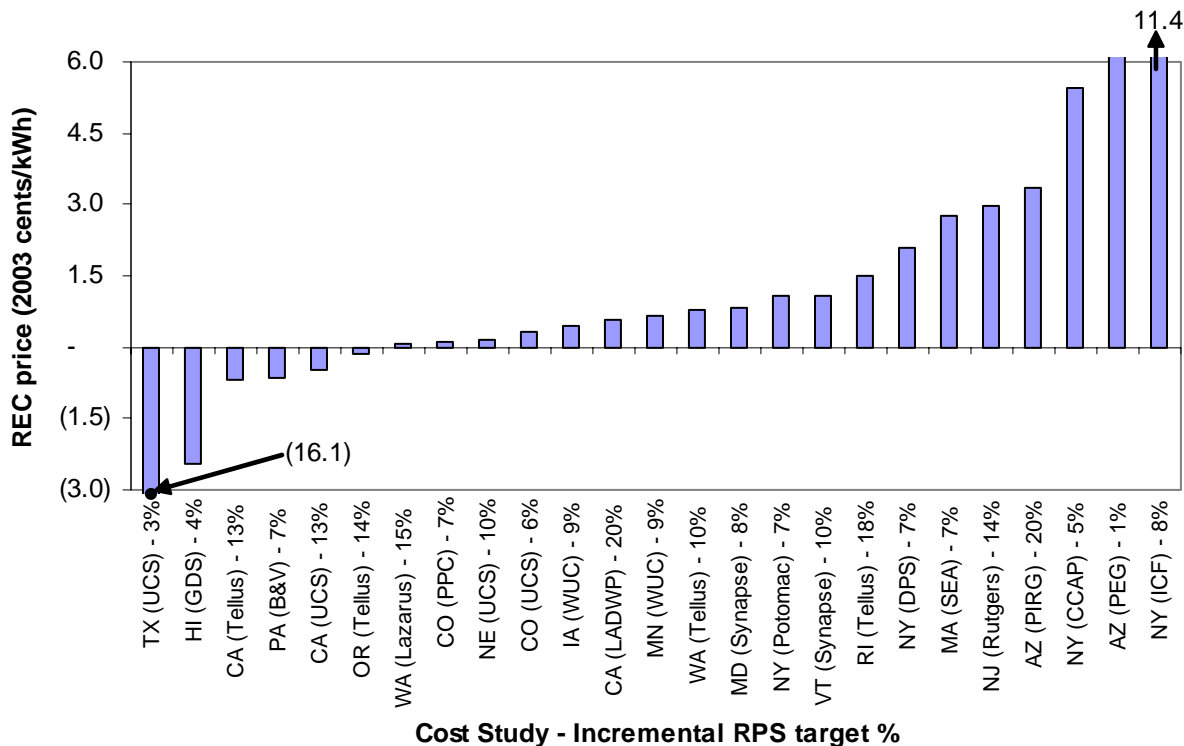
**Table 2. Spot RPS REC Prices (Class I only; current as of 1/3/06)**

State	Vintage	Bid (\$/MWh)	Offer (\$/MWh)
MA	2005	52.15	53.00
	2006	52.00	54.00
	2006-2008	43.50	47.50
CT	2005	-	2.50
	2006	6.50	8.00
ME	2005	0.20	0.30
NJ	2005-2006	6.50	7.00
	2006-2007	7.00	7.75
	2007-2008	7.25	8.25
MD	2005	1.50	3.00
TX	2005	8.00	10.50
	2006	-	13.50
	2007	-	13.50

Source: *Evolution Markets*

In addition to actual current REC prices, the RPS cost studies referred to earlier may be insightful in developing a bounding analysis of the potential cost impacts in Ohio. These studies, as shown in Figure 6, show projected rate impacts that are often well below 5% for RPS

standards that require incremental levels of renewable energy that max out at as high as 15% to 20%. The projected REC prices implied by these state RPS cost studies vary considerably (Figure 7), but all but two of the studies imply REC prices that are 3.0 cents/kWh or less.<sup>5</sup> In fact, the median implied REC price from the 25 studies is just 0.6 cents/kWh, and several studies show cost savings (shown in the Figure as negative REC prices).



**Figure 7. Implied REC Prices in First Year of Peak RPS Target Level**

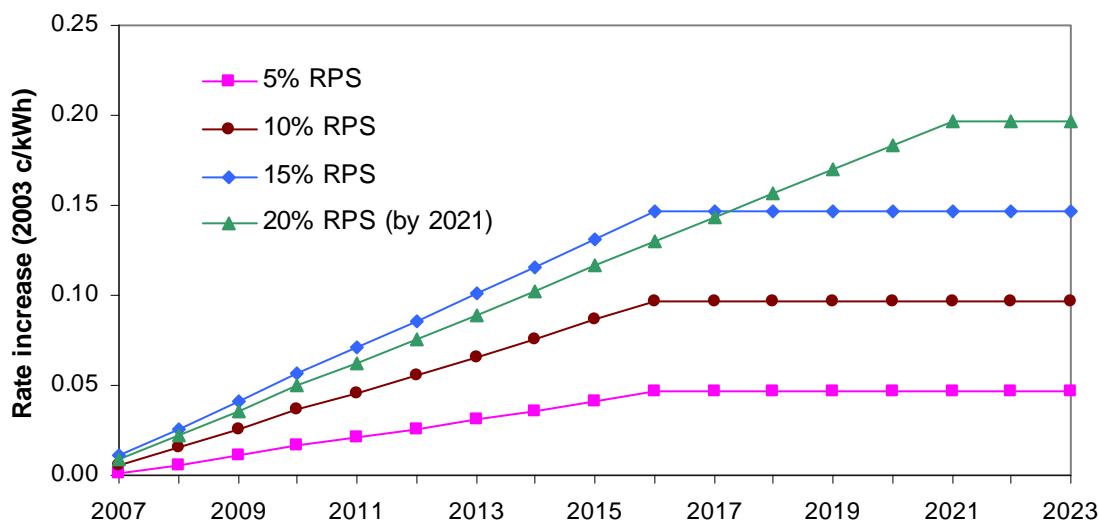
Using the data presented here on actual and projected REC prices under other state RPS policies, here we assume that in Ohio the maximum likely REC price will be 3 cents/kWh, assuming that adequate renewable resources are available to meet whatever RPS standards are put into place. We also develop rate impact estimates based on REC-price assumptions of 1 and 2 cents/kWh. It is recognized that these estimates represent – at best – first-cut projections of the potential rate impacts of an RPS policy in Ohio. Better estimates of potential rate impacts should be based on a more sophisticated, bottoms-up analysis of input costs; such analysis would find that higher RPS standards will likely yield costs that do not scale linearly with the RPS standard itself (that is, REC prices will increase as the standard itself increases).

Using our much more simplified approach, the following figures illustrate the potential rate impacts of Ohio RPS policies of different target levels under the three different REC price scenarios. Figure 8 illustrates the potential rate impacts of an Ohio RPS policy with REC prices

<sup>5</sup> To develop these implied REC prices, we divide the cents/kWh retail rate impacts shown in Figure 6 by the maximum incremental RPS target percentage for each modeled RPS. This yields the implied price for each kWh of incremental renewable electricity.

at 1 cent/kWh. Figures 9 and 10 show the expected rate impacts with REC prices at 2 cents/kWh and 3 cents/kWh, respectively.<sup>6</sup>

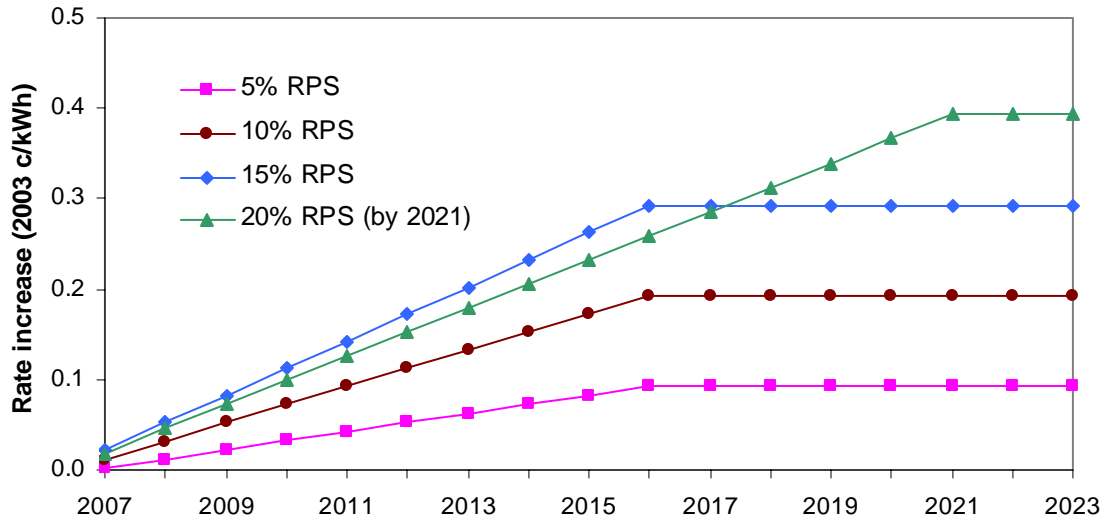
Under a 5% RPS (by 2016), average retail rates increase by 0.7% to 2.0%, depending on the assumed REC price. Average retail rates increase by 1.4% to 4.2% under a 10% RPS (by 2016), 2.1% to 6.4% under a 15% RPS (by 2016), and 2.9% to 8.6% under a 20% RPS (by 2021). These correspond to monthly electricity bill increases for the average residential customer ranging from \$0.40 to \$1.19 under a 5% RPS to \$1.68 to \$5.04 under a 20% RPS.<sup>7</sup> Because industrial customers pay electricity rates that are lower than residential customers, equally allocating incremental RPS costs to all customer classes on a cents/kWh basis would result in industrial rate increases that are 85% higher than residential rate increases (on a percentage basis).



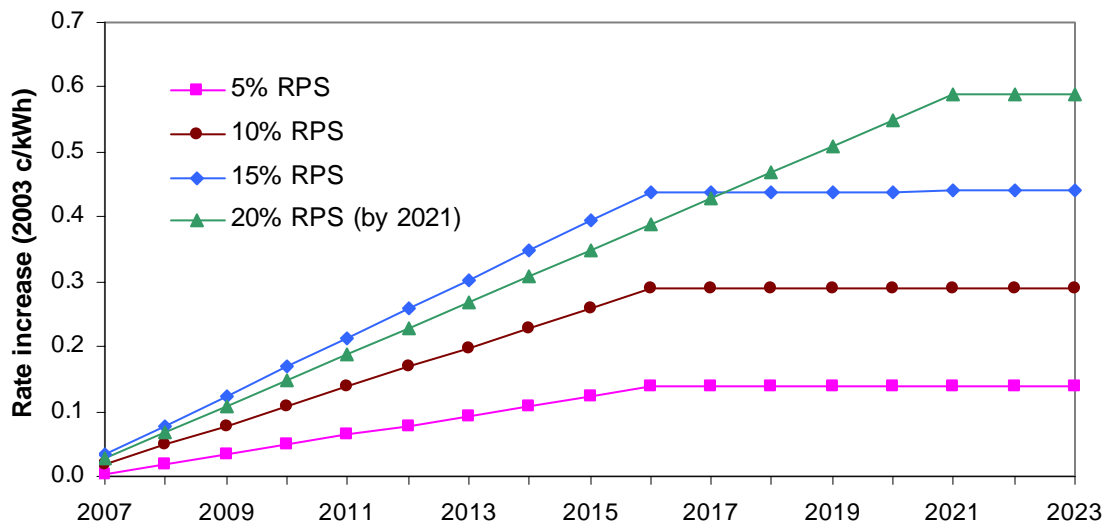
**Figure 8. Potential Ohio RPS Average Retail Rate Increase – 1 c/kWh REC Price**

<sup>6</sup> In each case, we assume that Ohio starts today with 0.4% of its electricity met with eligible sources of renewable energy. All incremental renewable energy needed to achieve the 5-20% standards are assumed to be purchased at 1, 2, and 3 cents/kWh, and renewable generation is assumed to scale linearly to the ultimate target starting in 2007. We assume that all electricity retailers in the state are obligated to meet the RPS, and we assume that load growth increases based on assumptions provided by Gregory Payne. Baseline retail rate forecasts for Ohio are based on EIA 2006 Annual Energy Outlook (AEO) projections for the ECAR region. We apply the current differential between Ohio and ECAR rates to AEO projections to generate a rate forecast for Ohio.

<sup>7</sup> Based on average residential monthly consumption of 855 kWh.



**Figure 9. Potential Ohio RPS Average Retail Rate Increase – 2 c/kWh REC Price**



**Figure 10. Potential Ohio RPS Average Retail Rate Increase – 3 c/kWh REC Price**

This bounding analysis suggests that relatively aggressive RPS target levels in Ohio may result in rate increases as high as 8% under a scenario of high REC prices. Of course, it is also possible that REC prices will be lower than any of the three levels shown above (and savings may even be achievable) – actual prices will depend on the design aspects of the RPS policy, as well as the interaction between renewable supply and demand in the state or region. We again recommend further and more detailed analysis if more accurate rate projections are desired.

## #5: What construction and operational jobs were created in Pennsylvania as a result of its RPS, and what would the impact be in Ohio?

The Pennsylvania RPS has not yet been implemented, so actual impacts cannot be presented. Similarly, in other states, RPS policies have been operating for too short a period (and data is too sparsely collected) to present actual construction and operation jobs created by those policies.

Because of these factors, we again rely on projected impacts from other states. Typically, macroeconomic impact analyses of renewable energy policies indicate that such policies are likely to result in some level of net employment gain. Table 3 shows the projected employment impacts from the state RPS cost-impact studies that model these effects (the table does not include the many RPS analyses which do not also model electricity rate impacts). All of the studies presented below predict some level of net employment gain, ranging from a few hundred to several thousand jobs created. Since the studies use different methods and units for estimating employment impacts of RPS policies of vastly different sizes, it is difficult to directly compare the results of one study to another. With this in mind, the employment figures in Table 3 do not appear to be strongly correlated with the incremental RPS generation required under each state’s policy. This may be due to different mixes of renewable technologies, assumptions concerning in-state versus out-of-state manufacturing, and incorporation (or lack thereof) of energy bill impacts into the macroeconomic analysis.

**Table 3. Employment Impacts Predicted by RPS Cost Studies**

Cost study	Cumulative Net Jobs Created	Timeframe of Analysis	Estimated Total Incremental RPS GWh	Model Used
Nebraska (UCS)	357	2003-2012	14,500	IMPLAN
Arizona (PEG)	600	1998-2010	5,700	Spreadsheet
Colorado (UCS)	1290 (in 2020 only)	2005-2020	46,500	Modified IMPLAN
Pennsylvania (B&V)	3747	2006-2025	186,620	RIMS II
New Jersey (Rutgers)	5700	2005-2020	90,300	NJ/ECON
Arizona (PIRG)	6100	2005-2020	96,500	Modified IMPLAN
Texas (UCS)	14600 (in 2025 only)	2005-2025	225,830	Modified IMPLAN

*Note: The employment figures from Pennsylvania (B&V) are based on a model of the state’s Alternative Energy Portfolio Standard, which includes requirements for energy efficiency and “Tier II” alternate (mostly non-renewable) energy sources. The Pennsylvania figure is calculated with the assumption that one job is equivalent to 20 job-years. Colorado (UCS) and Texas(UCS) figures represent non-cumulative net jobs created in the specific years in parentheses, but may include spillover effects from previous years.*

The analysis of the proposed Pennsylvania Advanced Energy Portfolio Standard (AEPS) predicts substantial employment gains from the implementation of the policy: more than 60,000 additional construction job-years and 13,000 additional operation job-years over the analysis’ 20-year timeframe. The Pennsylvania analysis included consideration of the direct and indirect employment gains associated with renewable energy, and the lost jobs associated with conventional fuels. The analysis assumes that all of the required new generation would be

located within Pennsylvania.<sup>8</sup> However, the proposed Pennsylvania AEPS incorporates energy efficiency and a significant portion of generation resources which are generally not considered renewable, and the results of the Pennsylvania analysis are thus not easily translatable to other states that have more standard RPS policy designs.

In a 2001 report titled *Repowering the Midwest*, the Environmental Law and Policy Center proposed a clean energy development plan to increase energy efficiency and renewable energy deployment in the Midwest. The Regional Economics Applications Laboratory (REAL) of the University of Illinois projected that the renewable energy investments in the plan would create 13,090 net jobs in Ohio alone by 2020.<sup>9</sup> Though the plan includes other policy measures in addition to an RPS, the report's findings are not inconsistent with those of other RPS employment impact analyses.

A large number of other studies and tools have been developed to estimate the macroeconomic impacts of renewable energy deployment efforts. We do not summarize those studies here.

Perhaps the single most significant determinant of net RPS employment effects is the location of the generating resources that are constructed and displaced and the location of their manufacturing facilities. State RPS policies are more likely to result in substantial employment gains when they result in the construction of renewable energy projects in-state, and when the renewable technology equipment is manufactured within the state's boundaries. Whether the renewable resources used to meet the Ohio RPS are located in- or out-of-state will largely depend on the design of the RPS itself. As a strong manufacturing state, however, we would expect that an aggressive RPS in Ohio would provide significant benefits to in-state manufacturers. Another important feature will be the cost of the RPS itself. Though macroeconomic benefits are often found in replacing conventional fossil generation with renewable energy, if that replacement comes with significant electricity rate impacts, then those rate impacts will have their own macroeconomic costs.

If Ohio is interested in these various impacts, and in developing an estimate of the macroeconomic impacts of a state RPS policy, we would recommend that the state consider conducting its own macroeconomic impact analysis.

## **#6: How many emissions have been offset in other states, tons, percentage of emissions, etc.?**

The RPS policies in other states have not been operating long enough to have a record of emissions reductions. In addition, for pollutants that are capped under a cap-and-trade program (SO<sub>2</sub>, and NO<sub>x</sub> in some states), increased use of renewable energy will not necessarily directly reduce pollutant emissions. Instead, increased renewable energy will help free-up emissions

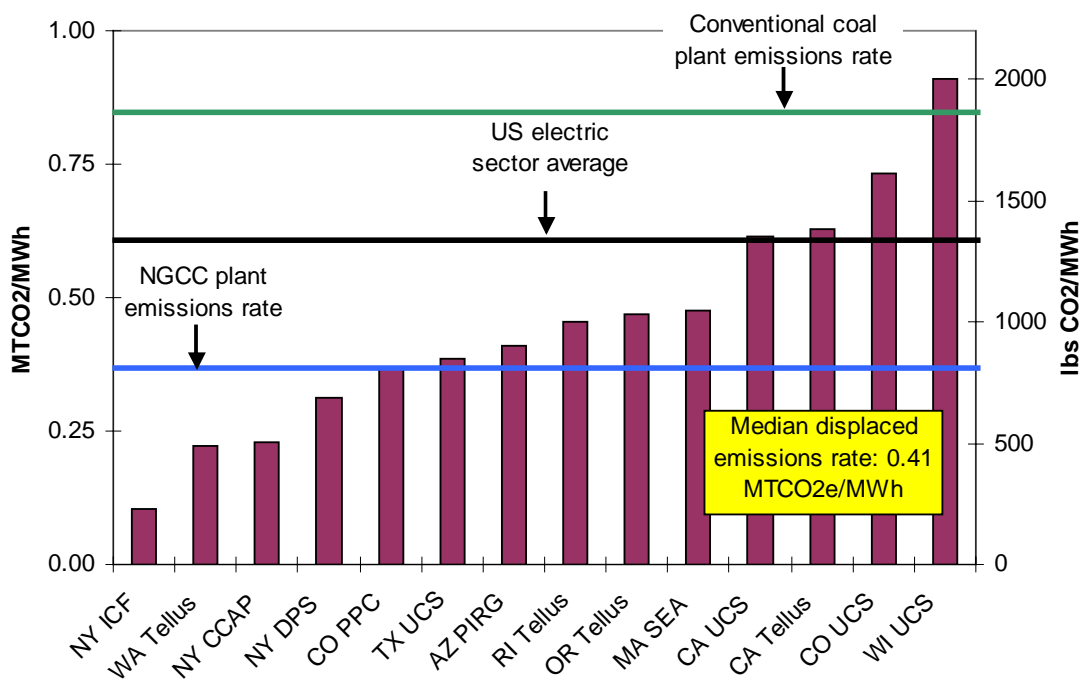
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<sup>8</sup> The analysis also assumes that some fraction of the construction and operation expenses for both renewable and conventional generating equipment is made out of Pennsylvania. This fraction varies by technology.

<sup>9</sup> Regional Economics Applications Laboratory. *Job Jolt: The Economic Impacts of Repowering the Midwest: The Clean Energy Development Plan for the Heartland*.

allowances that others will use, potentially leading to no net change in aggregate emissions. Also note that allowance sales are regional in nature, so under current regional and national cap-and-trade programs, it is difficult to ensure specific in-state benefits.

A number of RPS cost studies have modeled the potential carbon dioxide (CO<sub>2</sub>) emission reductions resulting from RPS policies. Figure 11 shows the implied CO<sub>2</sub> emissions rates of electricity generation displaced by RPS resources. The median displaced CO<sub>2</sub> emissions rate of 900 lbs/MWh is low compared to the national electricity sector average of 1350 lbs/MWh,<sup>10</sup> which reflects an expectation that RPS resources in many regions will largely displace generation from natural gas plants. In fact, the median displaced CO<sub>2</sub> emissions rate is just slightly higher than the emissions rate of a new combined-cycle natural gas generator.



**Figure 11. Projected Rates of CO<sub>2</sub> Emissions Displaced by RPS Policies in Initial Peak Target Year of RPS**

A much smaller number of cost studies model the potential nitrogen oxide (NO<sub>x</sub>) and sulfur dioxide (SO<sub>2</sub>) emission reductions of RPS policies (Figures 12 and 13). These studies – of RPS policies in Arizona, New York, and Massachusetts – predict fairly low rates of displaced NO<sub>x</sub> and SO<sub>2</sub> emissions.<sup>11</sup> Each of these studies projects that renewable generation will primarily displace natural gas fired generation, which has lower NO<sub>x</sub> and SO<sub>2</sub> emissions. Though natural gas plants may represent the marginal generating unit in these states, Ohio has a much “dirtier” emissions profile, and an Ohio RPS should provide much greater emission reductions on a per-

<sup>10</sup> U.S. EIA Annual Energy Review 2005

<sup>11</sup> New York (DPS) does not account for emissions reductions that occur out of state.

MWh basis. Note again, however, that increased renewable energy generation will not necessarily reduce pollutants that are covered under a cap-and-trade regime, unless those renewable units are both allocated emissions allowances and are required to retire them. Even then, in-state benefits cannot be ensured because cap-and-trade programs are regional or national in scope.

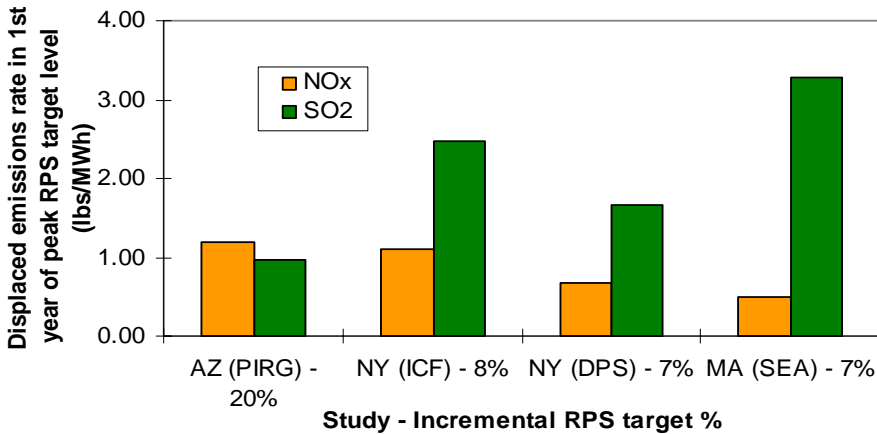


Figure 12. Annual Displaced Emissions Predicted by RPS Cost Studies

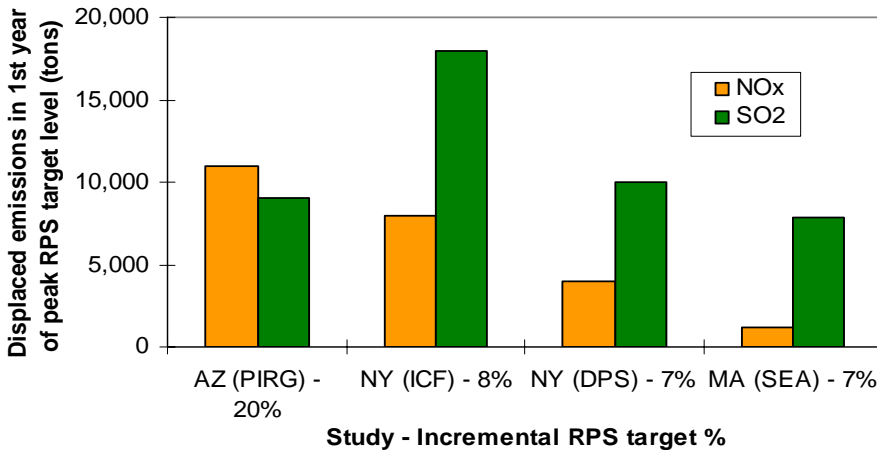


Figure 13. Displaced Emission Rates Predicted by RPS Cost Studies

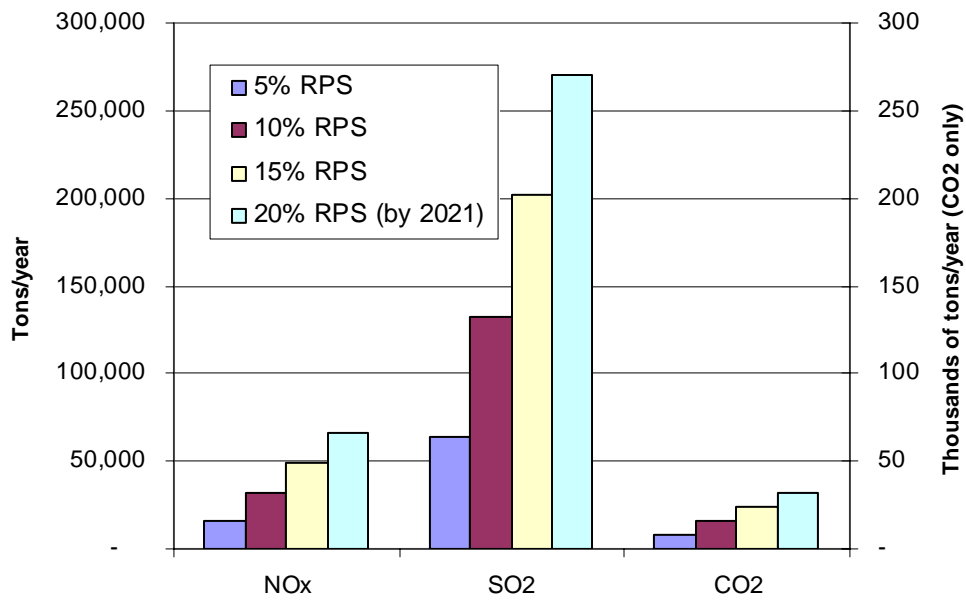
It is relatively easy to develop estimates of the pollution emissions reductions that **may be** achievable under an Ohio RPS of 5% to 20%. We assume that Ohio starts with 0.4% renewable energy today, and ramps up that generation to 5-20% (by 2016 for the 5-15% standards, and 2021 for the 20% standard) by relying on newly built renewable energy generating units. We further assume that the incremental renewable generation offsets conventional power with emissions rates of: 1,753 lbs/MWh for CO<sub>2</sub>, 3.6 lbs/MWh for NO<sub>x</sub>, and 14.7 lbs/MWh for SO<sub>2</sub>. These emissions rates represent the average emissions rate for all electricity generators in Ohio in 2004 (provided by Gregory Payne, ODOD). These emissions rates overestimate the true emissions benefits of renewable energy. First, intermittent renewable resources such as wind

power often tend to offset peaking rather than baseload units. In Ohio, baseload units are predominantly coal plants, which may have higher emissions rates than some of the generators used for peaking purposes (which are more likely to be natural gas fired). Second, renewable generation will not only offset existing generation units, but may also slow the construction of new and cleaner generation units that have much lower “marginal” emissions rates. Third, emissions regulations are strengthening over time. As a result, marginal and average emissions rates should decline over time. We have ignored this fact, and instead have assumed that the 2004 average emissions rates will represent the marginal emissions savings associated with renewable energy for the entire forecast period. Finally, as discussed above, ensuring in-state emissions benefits from renewable energy under a cap-and-trade program can be challenging. As such, the numbers presented here are best considered upper-bound estimates, and not particularly realistic estimates of the overall emissions savings potential of renewable energy.

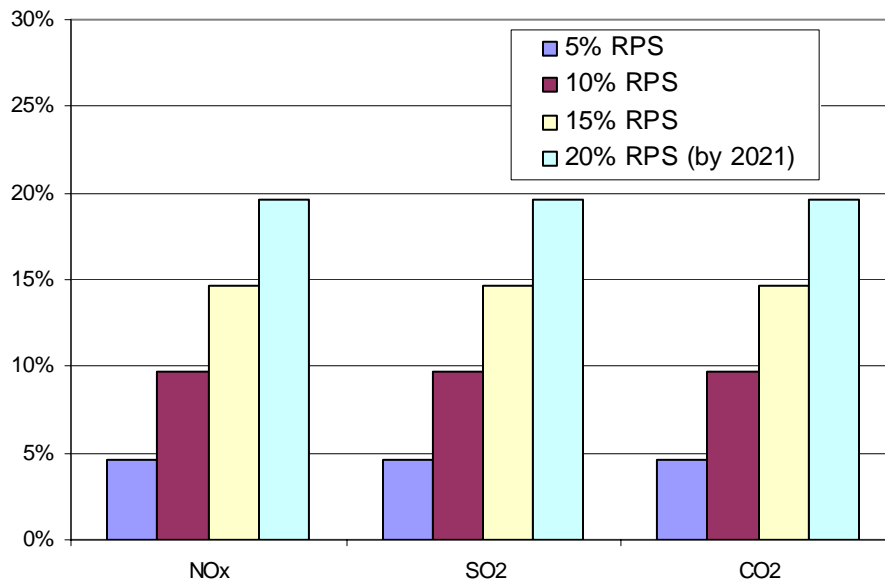
Figures 14 and 15 show the results of our admittedly crude calculations. Not surprisingly, we find that the potential emissions reductions in 2021 are commensurate with the RPS target levels. A 5% RPS would reduce annual electricity-sector pollutant emissions by 4.6% in 2021, and a 20% RPS would reduce emissions by 19.6%.<sup>12</sup> These percentage reductions simply assume that renewable generators offset emissions at the rate of average electricity-sector emissions that occur at that time. Figure 15 calculates potential emissions reduction in terms of tons of pollutants. These estimates, however, should not be relied upon as they assume that average emissions rates will not change over time. Both sets of estimates also assume that the emissions reductions caused by displacing conventional fuels are permanent (that is, if a cap-and-trade regime is used, that the renewable units are both allocated emissions allowances and are required to retire them), and that the benefits accrue to Ohio (i.e., that the displaced generation units and emissions provide direct benefits to the state – e.g., are not located downwind). Both of these assumptions may be aggressive, as are the emissions rate assumptions used. In reality, it is likely that an Ohio RPS would reduce electricity-sector emissions by a fraction that is considerably smaller than that shown here.

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<sup>12</sup> These calculations assume that the average emissions rates described above remain constant through 2021. As noted in the above text, this assumption is aggressive in that, over time, one would expect new renewable energy units to increasingly displace the construction of new and cleaner fossil generation, and because emissions regulations will strengthen over time.



**Figure 14. Potential Annual RPS-Induced Emissions Reductions in 2021 (Absolute Terms)**



**Figure 15. Potential Annual RPS-Induced Reductions in 2021 (Percent Terms)**

## **#7: What would be the impact of potential Ohio Renewable Portfolio Standard on Ohio's non-attainment status? What percent renewable standard would be required to impact non-attainment status?**

Recommendation: Establish a dialogue with OEPA Air Quality Division to consider options for inclusion of renewable energy and possible energy efficiency into the Clean Air Interstate Rule State Implementation Plan

The Clean Air Interstate Rule (CAIR) will reduce NO<sub>x</sub> emissions by 272,000 tons (427%) from electric generating units by 2015 compared to 2003 emission levels in Ohio. The program allocates emission allowances to generating units based on an established rate that will reduce emissions to the targeted amount. This makes it more economically attractive for electric generating units to install emission reduction technology (scrubbers) compared to buying allowances on the open market. This is because at the end of the year, all participants must hold as many allowances as they emitted either through reducing emissions directly or through purchasing allowances on the open market. 1 allowance equals 1 ton of emissions.

Total emissions for any given state are not capped, only the amount of total emissions for the region. What drives the economics of the trading market and in turn the amount of emission reductions one tries to attain is the number of allowances initially allocated (if you don't have enough you buy, if you have more than you need, you sell).

The rate for the current NO<sub>x</sub> SIP allowance allocation process is set at 0.0015lbs/kwh. Since Ohio electric generating units generated 65,946,666 MWh during the base case year (2001), they were allocated 49,460 allowances. During the 2000 ozone season, Ohio electric generating units emitted 169,068 tons of NO<sub>x</sub> using the average emission rate for 2000 for Ohio electric generating units of 0.005127 lbs/kwh. This means that Ohio electric generating units would have had to secure over 119,608 allowances on the open market, if they had not reduced emissions through the installation of emission reduction technology equal to its 49,460 tons of allowances between the 2000 period and the 2004 ozone season when the NO<sub>x</sub> SIP was first implemented in Ohio. Companies consider this because if it is not deemed cost effective to install emission reduction technology, companies can simply buy allowances on the open market. The decision to buy allowances or install technology is driven by the current price of the allowance, the age of the generating unit (if a plant is going to be decommissioned soon, you would not want to install emission reduction technology), and the amount of kwh you plan on generating.

Had NO<sub>x</sub> emissions held at 2000 levels, utilities would have spent \$358,822,608 per year to purchase allowances on the open market that averaged \$3,000 per allowance. However, utilities significantly reduced emissions for 2004 in the face of such potential costs. 44,645 tons of NO<sub>x</sub> were emitted during the 2004 ozone season in Ohio, less than the initial allocation. This is a reduction of over 378% compared to 2000 levels.

2004 total NO<sub>x</sub> emissions for the year in Ohio was 270,448 tons, compared to 382,102 tons in 2000, a reduction of 41%. Electricity generated during the 2004 ozone season (May 1<sup>st</sup>-September 30<sup>th</sup>) accounted for 44% of electricity generated that year, but only 16% of NO<sub>x</sub> emissions.

Under CAIR, yearly emission allocations will be reduced to 93,000 tons in 2009, and 83,000 tons in 2015. The actual cost of CAIR NO<sub>x</sub> allowances is currently not established since compliance doesn't begin until 2009, but estimates have ranged from \$1,000-2,000 per ton. By 2015, utilities will therefore need to reduce emissions by 228,044 tons when you include forecasted additional generation needs (10,795,116,000 kwh) at the current (2004) rate of emissions/kwh (0.003269 lbs/kwh). If Ohio utilities instead chose to purchase all of the needed allowances on the open market, they could expect to pay between \$228-456 million dollars using the estimated \$1,000-2,000 price per allowance.

If a Renewable Portfolio Standard were established that required by 2015 that 10% of electricity sold in Ohio came from renewable energy by 2015, 6,572MW of 0.3 rated wind turbine generation capacity would need to be constructed. This would produce the needed 17,271,395,100 kwh to supply 10% of the expected sales in 2015. The technical capacity of class 3 winds at a 70M height for Ohio is estimated at 97,504MW. An economically developable MW capacity in Ohio based on conservative Ohio Wind Working Groups estimates for on land production is 2000 MW.

If 10% of electricity sales came from emission free renewable sources, NO<sub>x</sub> emissions would be reduced by 31,071 tons in 2015 if CAIR was not implemented. With CAIR, emissions reductions realized from an RPS can only be expected to equal the number of allowances that it is given which is dependent on the allocation rate given to accomplish the cap. This rate is expected to be 0.001001468 lbs/kwh in 2015 under CAIR. Renewable energy under a cap and trade system would be expected to offset the same amount as nuclear energy on a lbs/kwh basis. Both don't produce emissions. The only difference is you don't question what is the marginal emissions rate that nuclear power offsets since it is allocated emission allowances at the same rate as any other electric generating unit, and that allocation rate essentially becomes the emission reduction rate realized. The same should be the case for renewable energy.

Since only 83,000 tons will be allocated to Ohio, a 10% RPS can be expected to reduce emissions in 2015 by 8,648 (if 10% of sales were required to be generated in Ohio, this would equal 10.4% of generation since Ohio currently imports electricity). This would have the value of \$8.6- \$17.2 million per year depending of the cost of CAIR allowances since utilities wouldn't have to generate electricity from units that emit NO<sub>x</sub>. An RPS' value of awarded allowances under CAIR ranges between 0.05- 0.1 cents/kwh.

A 10% RPS would create 17,271,395,100kwh, which would allow 6,039,301,100kwh or 3.6% of traditional electricity generation to go offline by 2015 and would cover all projected growth in the electricity generation sector in Ohio based on PUCO 2015 forecasted electricity sales.

What you do with allowances allocated to renewable sources is an important question to consider. The options are to sell the allowance on the open market, retire the allowance so that the regional cap is reduced, or to bank the allowance for future use. The retirement of allowances from an RPS is not as important as the fact that it off-sets Ohio generated electricity and that it is given allowances for the electricity it produces. If Ohio awarded renewable sources retire their allowances from the regional program it would have the affect of raising the price of allowances on the open market, since allowances would be more scarce. This would lower the allowable tonnage emissions for the region,

but not necessarily in Ohio since retirement of Ohio based renewable allowances would not stop Ohio utilities from going outside of the state to purchase needed allowances on the open market.

Regardless of whether allowances are retired, when Ohio renewable sources are given allowances from the total amount allocated to Ohio, this changes the amount allocated to traditional sources of electricity generation. This in turn changes the economic perspective of what companies consider to be cost-effective to reduce emissions at the plant level versus purchasing on the open market to comply. It also reduces the amount of electricity needed to be produced from traditional NOx emitting sources.

SO2 is also capped and allowances are given out to electric generating units, so there are savings here as well on the potential cost of compliance. The major difference between the SO2 and the NOx program under CAIR is that the State of Ohio does not have the authority to provide set-asides for renewable energy under the SO2 cap and trade program like it does with the NOx implementation.

Ohio is currently a net importer of electricity and operates in two regional transmission organizations that allow power producers in Ohio and in other states to generate electricity in one state and sell it in another. An Ohio RPS, might therefore offset imported electricity from downwind states, thereby not affecting emission reductions here in Ohio.

For Ohio to gain specific economic and emission reduction benefits, an RPS must be carefully framed. An Ohio RPS needs to have implementation and legislation goals to produce power in Ohio that offsets traditional sources of Ohio generated electricity. Electricity imported into the state from upwind states would also positively affect Ohio's air quality, but other economic impacts would not be realized like job creation, and others through this policy. This is due to the transport nature of pollutants and their affect on downwind states.

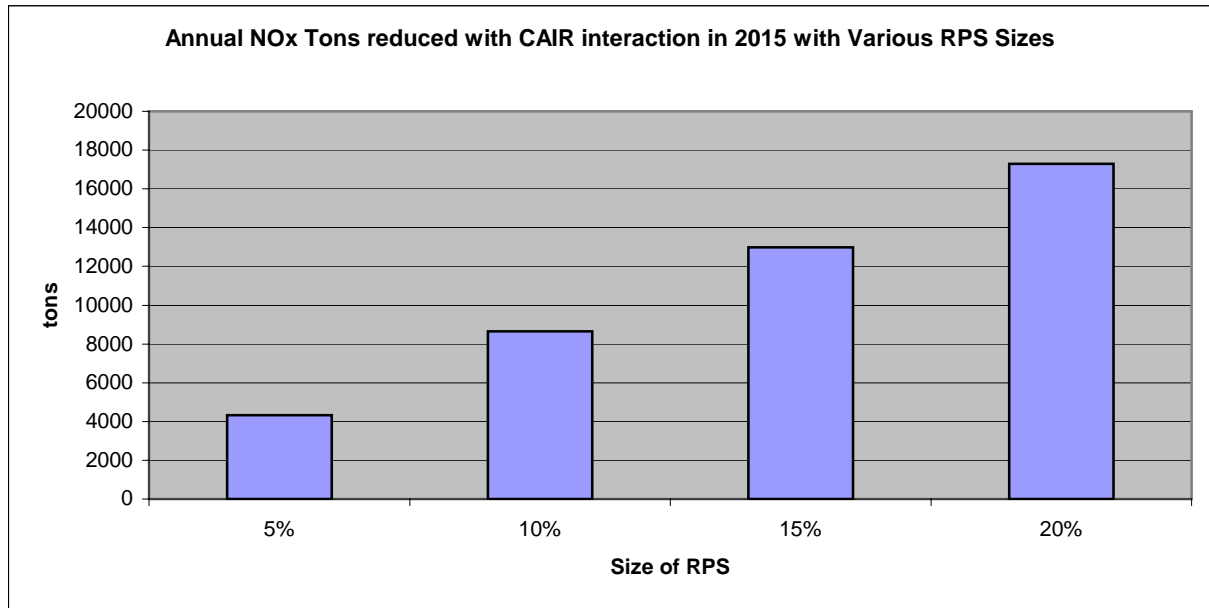
Current CAIR projections do not bring Ohio out of non-attainment in a number of counties even in 2015 with dramatic cuts required. An Ohio RPS could help push Ohio into attainment. Modeling tools are available from the Ohio EPA to gauge this impact. The Ohio EPA is currently running models of different strategies through their photochemical grid model to see what will be required in addition to the current CAIR rules to bring Ohio into compliance by 2009 and 2015. This model includes impacts from upwind states on Ohio's air quality, and emissions from specific sources in Ohio on downwind Ohio counties. The transport of pollutants is one of the factors the OEPA model takes into account.

In consultation with the Ohio EPA, the Office of Energy Efficiency could provide potential emission reductions under an Ohio RPS that could be run through the photochemical grid model that would predict the impacts on each counties non-attainment status in the State of Ohio in 2009 and 2015.

If CAIR didn't exist, an RPS would need to reduce emissions by 215,197 tons by 2015 to accomplish the same results as CAIR. This would translate to 119,620,055kwh of electricity produced by emission free renewable sources by 2015, or 45,518 MW at a capacity factor of 0.3 coming from wind power. This would potentially have the same effects as CAIR and would bring all 33 counties into attainment for 8-hour ozone and would bring 15 out of 27 counties into attainment for PM 2.5. This

would in turn require a 72% RPS by 2015 and wouldn't affect emission reduction impacts from other states reductions currently incorporated into the CAIR model since other states wouldn't be subject to an Ohio RPS, but are subject to CAIR.

It is therefore recommended that any RPS emission reductions be framed in conjunction with CAIR and as a tool to go beyond CAIR to help bring the remaining 12 counties in non-attainment by 2015. Reducing emissions 10% beyond CAIR could have a significant impact on these remaining counties. The exact impact would require Ohio EPA CAIR modeling to determine.

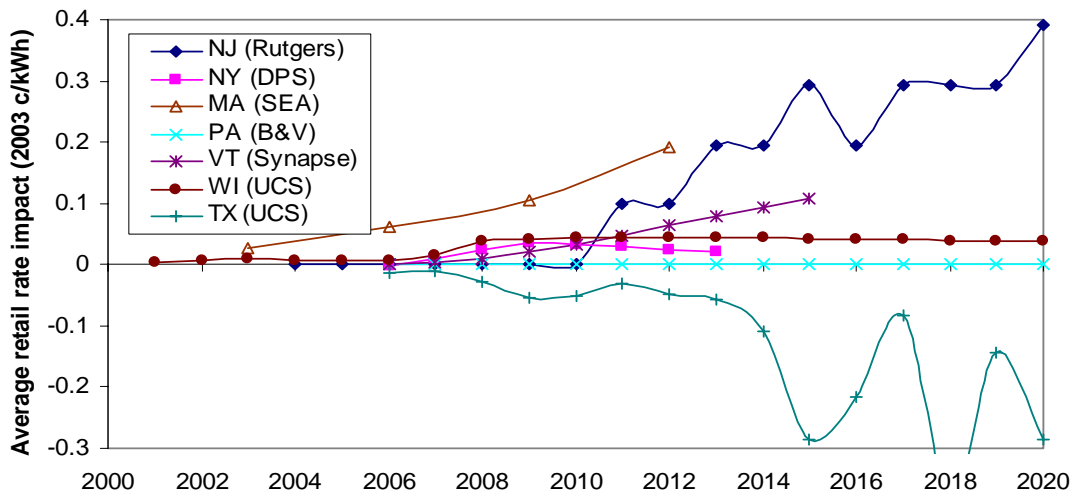


2004 kwh generation	148,300,000,000
Estimated Sales of Electricity 2015 (10% RPS)	172,713,951,000
kwh total generated during 2015	165,756,669,000
Ton allocation for CAIR 2015	83,000
lbs allocation for CAIR 2015	166,000,000
lbs/kwh allocation 2015	0.0010015
Needed allowance purchase, or emission ton reduction under CAIR 2015	0
Cost of Allowance/ton (\$)	2,000
Cost paid by utilities to be in compliance (\$)	0
lbs/kwh emitted 2015	0.001001468
Number of kwh required under 10% of sales RPS	17,271,395,100
Estimated % of generation required with under RPS of generation allocation for Ohio	0.104197286
Number of allocations required for RE with 10% of sales	8,648
Value of allocation	2,000
Value of allocation given to RE through 10% RPS (\$)	17,296,750
tons emitted by electric Generating Units with 10% RPS	74,352
pounds emitted by electric Generating Units with 10% RPS	148,703,250
kwh total generated from non-RPS sources	148,485,273,900

Number of tons allocated to Ohio Utilities for 2015	83,000
Number of lbs. allocated to Ohio Utilities for 2015	166,000,000
Difference (tons) between with RPS and non RPS emissions	8,648
Difference (lbs)	17,296,750
Cost of Allowance/ton (\$)	2,000
Cost paid by utilities to be in compliance (\$)	17,296,750
lbs/kwh reduced with RPS (estimated)	0.001001468
lbs reduced with RPS (estimated)	17,296,749.53
Tons reduced with RPS (estimated)	8,648.37
Value of RE allowances with 10% RPS	17,296,750
Value per kwh from Allowance Sales from RE generated during ozone season from RPS for and impacts on NOx SIP compliance costs that would be realized by utilities	0.00100147

### #8: What are cost/savings in other states over the years, not just one static date of RPS?

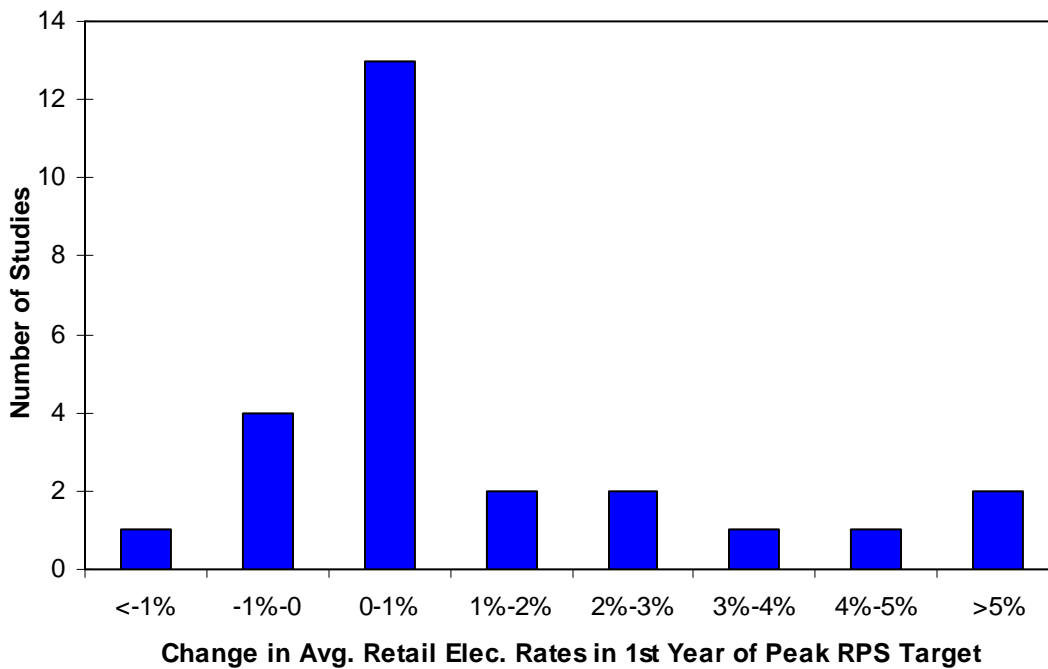
The projected RPS rate impacts presented earlier for other states focused on the year in which the maximum RPS percentage standard is reached. Of course, actual rate impacts will vary over time as the percentage target increases. Typically, the magnitude of RPS cost impacts are projected to increase throughout the RPS implementation period, as renewable energy targets grow to cover a greater percentage of retail load. This trend is apparent for many of the studies presented in Figure 16, which shows projected average retail rate impacts for seven studies throughout each study's RPS implementation period. Figure 16 includes a subset of the studies conducted in the Northeast and Midwest.



**Figure 16. Projected Rate Impacts During RPS Implementation Period**

Projected long-run RPS rate impacts, while often higher than the rate impacts during earlier years of the RPS implementation period, are typically still quite modest. Figure 17 shows the

distribution of long-run RPS rate impacts projected by the RPS cost studies.<sup>13</sup> As the figure indicates, roughly half of the studies in our sample report base-case rate increases of between 0% and 1%, and five studies project rate savings. Eight studies predict rate increases above 1%.



**Figure 17. Distribution of Implied Long-Run RPS Rate Impacts**

The results presented so far have focused on rate *projections*, based on study results. Some states have now had enough experience to report actual costs, though in many states such information is not publicly available.

Early experience with actual RPS policies supports the expectation that rate impacts will generally be modest, though in some cases actual impacts have been greater than original projections. Table 4 shows recent 2006 REC prices for four states in which 2006 RECs are currently available in the spot market, and in which REC prices are expected to be a reasonable indicator of aggregate compliance costs.

Based on current REC prices and the 2006 RPS targets in these states, the estimated 2006 rate impacts range from 0.008 c/kWh in Maryland to 0.14 c/kWh in Massachusetts – roughly 0.1% to 1.2% of current retail rates. We obtain these estimates by simply multiplying the REC price by the 2006 RPS target level (estimated rates for states with multiple resource tiers and target levels are calculated by summing the products of the respective REC prices and target levels). This approach assumes that RPS compliance is entirely achieved through the spot market, which may overestimate rate impacts in some cases where longer-term REC transactions are priced at lower price levels.

<sup>13</sup> As before, we use the cost data from the year in which the modeled RPS first reaches its peak target level as a proxy for the long-run cost impact.

**Table 4. Recent 2006 REC Prices and Estimated 2006 Rate Impacts**

State	REC Product	2006 REC Price (c/kWh)	2006 RPS Target Level	Estimated 2006 Rate Impact (c/kWh)	% Rate Increase
Connecticut	Class I	0.8	3.5%	0.030	0.3%
	Class II	0.1	3%		
Massachusetts		5.4	2.5%	0.135	1.2%
Maryland	Class I	0.3	1%	0.008	0.1%
	Class II	0.2	2.5%		
New Jersey	Class I	0.8	2.9%	0.052	0.5%
	Class II	0.3	2.5%		
	Solar	22.5	0.1%		

*Note: REC prices are Evolution Markets LLC offer prices as of 1/3/06. Maryland Class I price is for 2005; Maryland Class II price is for 2004-2005. New Jersey prices are for the 2006-2007 planning years. Percent rate increase based on 2004 retail rates.*

New York employs a central procurement mechanism. The utilities, in aggregate, are to collect roughly \$24 million in 2006, rising to \$167 million in 2013. These numbers are subject to possible future revision. To collect these funds, National Grid’s surcharge is 0.0276 cents/kWh for 2006. The surcharges will rise over time as more and more procurements take place. Ultimately, under current estimates, the surcharges will increase to a maximum of ~2% of retail rates by the year 2013.

In still-regulated electricity markets, RPS compliance is typically achieved through long-term contracts with renewable generators, and the cost of these contracts is not typically made public. Nonetheless, renewable energy contracts signed in California have so far all been below the “market price referent” – the projected cost of gas-fired capacity – suggesting that the state’s RPS has perhaps so far yielded cost savings (though the MPR comparison does not address any additional transmission or integration costs associated with the renewable energy investments). Similarly, contracts signed under the first RPS solicitation in Nevada were apparently not “above-market”, on average. Costs in Texas, Minnesota, and New Mexico have also all been modest, and rate savings may have been generated in some of these states.

**#9 What were the State Energy Offices’ impressions in PA, TX, and NJ of the utility response to a Renewable Portfolio Standard when first proposed, and currently?**

**Texas**

From conversations and e-mail with Dub Taylor, Director of the Texas State Energy Office

No utilities came out in opposition to the initial RPS that was established in 1999, (2000MW by 2007) or the 2005 expansion that established a new standard of 5,000 MW by 2015. The Texas system requires that a percentage of sales by utilities comes from renewable sources. Municipal and co-ops are exempt from this legislation. The initial RPS came about as part of the deregulation process, which was pushed heavily by industrial customers. The capped price was

indexed to the price of natural gas. Since then natural gas prices have escalated, and utilities may charge the price to beat at a fully indexed natural gas price. The initial 2000 MW RPS was driven by a combination of the Deliberative Polling process that was part of Integrated Resource Planning and the environmental community. The Deliberative Polling process was conducted statewide by all investor owned utilities and had different representatives from all customer classes and essentially asked customers what they wanted from their utility in the future. Over half said renewable energy should be the first option for new generation and also that they were willing to pay more per month to do this.

PXU- the largest utility in the state claims that “we like renewables,” it’s cheap, just intermittent nature has to be incorporated into the system accordingly.

“Most utilities in Texas are forced into using new technology, still have old meters, but being pulled by competitive pressures to change.” Utilities thought an RPS would be difficult, but not as big a problem as they thought. They can manage it since it’s not too large, 2,000 MW of 80,000 MW in the entire system. Texas AEP bought Central/Southwest Company as one of its four different operations. CSW was the most progressive utility in Texas and that culture hasn’t changed much since AEP took over.

The 2005 legislation has also benefited utilities because they can create transmission for needed new renewable that can also be used by traditional sources of generation. The Public Utilities Commission has allowed utilities to rate base any additional transmission needs to cover the new wind farms. The RPS was also increased because Texas hit its target early and because of the upswing in natural gas prices and because it wanted to create additional market certainty for renewable power. The 2005 expansion also established a carve out for non-wind renewable sources of 500MW, since the majority of previous RPS generation has come from wind.

“Utilities could have gotten the RPS expansion killed at any point, but they didn’t. They have a strong impact on legislature and Texas AEP’s CEO was part of process to expand the RPS to 5,000 MW in 2005.” The Texas Energy Plan 2005 unanimously recommended prior to the 2005 legislative session that the RPS should be expanded. This commission was made up of utilities (Texas AEP CEO), senators, representatives, businesses, industry, power marketers, chemical companies, waste management, lawyers, and investment firms.

“Utilities are learning that an RPS is not a threat financially, and that it doesn’t compromise operations and that it can have many public relations co-benefits.”

## **Pennsylvania**

From conversations with Eric Thumma, Director of the Bureau of Energy, Innovations and Environmental Technology for the PA Dept. of Environmental Protection

Utilities first impression was, if they were able to have cost recovery of potential costs from RPS, they were fine with it. First Energy lobbied for it actually. Exel energy initially opposed legislation, but got on board before the legislation was finalized. It is important to analyze what the demand is and what it will be in the future accurately, and to know what the potential of

renewable sources are in the state before any standard is set. Maine is a bad example of an RPS, since no new generation will be required. It is important that for economic development that generation is installed in your state. The way the bill is drafted is key, language will have to consider commerce clause in the way it is worded as well.

Pennsylvania has a Tier 1 and Tier 2 requirements in its' RPS. Tier 1 is renewables- wind, solar, biomass, Tier 2 is waste coal, coal mine methane, IGCC, energy efficiency. 2<sup>nd</sup> Tier will not drive any new development of energy efficiency since Tier 2 goals have already been complied with mostly from existing sources. Energy efficiency is nice to have but is more difficult to monitor and measure than kwh generation from a renewable source. Hawaii also has an energy efficiency standard as part of its' RPS.

From conversations with John Hanger, President and CEO of PennFuture, a statewide environmental organization.

Political leadership is needed from Governor's office and Legislature. It is mportant to identify up front to the utilities that they will be part of the process, but not to hold up the process.

### **New Jersey**

From conversations and e-mail with Mike Winka, Director of the Office of Clean Energy, New Jersey Board of Public Utilities

“We are in the process of expanding by regulation our RPS from 4% with a 90 MW PV set aside in 2009 to 20% by 2021 with a 1500 MW PV set aside. The overall rate impact is relatively small we are looking at a \$1 to 2 per average household cost in 2005 increase to about \$20 per household in 2021. All in all the Utilities have been relatively supportive.”

The initial RPS came through statute in 1999 as part of deregulation as well as a System Benefits Charge, and an environmental and emissions disclosure clause on utility bills. The Governor's Task Force was established to look at expanding the RPS, which has since occurred. Renewable energy can come from anywhere in the PJM region. The RPS went from 4% by 2008, to 20% by 2020. A 3% increase in electric price by 2020 on the low end is expected. A 14% increase by 2020 is on the high end. There is also a solar carve out. There is a safety value if Renewable Energy Credits (REC) are not available, it will freeze, but if more RECs are available, they can expand RPS and rates. First Energy (JCPL) and PSGE didn't object, Atlantic was for green power, and Roland, and Com Ed are small in NJ, but didn't oppose it.

RPS doesn't apply to municipal utilities, which only 3% of sales in New Jersey. As part of their State Implementation Plan for NOx, the RPS gets credit and they retire them. New Jersey is also a part of the Regional Greenhouse Gas Initiative (RGGI) to reduce greenhouse gas emissions. Emissions are tied to what is coming off the grid.

The PV market must be tied to the grid to see more economic benefits. New Jersey has gone from 2 companies doing PV installations, to 100 companies with 2-3 average per company.  
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