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Weighing the Costs and Benefits of Renewables Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections

Cliff Chen, Ryan Wiser, and Mark Bolinger

Environmental Energy Technologies Division

January 2007

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Executive Summary

Introduction

State renewables portfolio standards (RPS) have emerged as one of the most important policy drivers of renewable energy capacity expansion in the U.S. Collectively, these policies now apply to roughly 40% of U.S. electricity load, and may have substantial impacts on electricity markets, ratepayers, and local economies. As RPS policies have been proposed or adopted in an increasing number of states, a growing number of studies have attempted to quantify the potential impacts of these policies, focusing primarily on projecting cost impacts, but sometimes also estimating macroeconomic and environmental effects.

This report synthesizes and analyzes the results and methodologies of 28 distinct state or utility-level RPS cost impact analyses completed since 1998. Together, these studies model proposed or adopted RPS policies in 18 different states. We highlight the key findings of these studies on the costs and benefits of RPS policies, examine the sensitivity of projected costs to model assumptions, assess the attributes of different modeling approaches, and suggest possible areas of improvement for future RPS analysis.

Key Findings

Projected rate impacts are generally modest. Seventy percent of the RPS cost studies in our sample project base-case retail electricity rate increases of no greater than one percent in the year that each modeled RPS policy reaches its peak percentage target.[1] In six of those studies, electricity consumers are expected to experience cost *savings* as a result of the RPS policies being modeled. On the other extreme, nine studies predict rate increases above 1%, and two of these studies predict rate increases of more than 5%. Though most of the studies project relatively limited impacts on retail electricity rates, the wide range of impacts shown in Figure ES - 1 underscores the large variability among the studies' results. When translated to monthly electricity bill impacts for a typical residential customer, these impacts range from a savings of over five dollars per month to an increase of over seven dollars per month.[2] However, the median bill impact across all of the studies in our sample is an increase of only $0.38 per month.

[1] We use the term "base case" to refer to the baseline RPS scenario, while we use the term "reference case" to refer to the business-as-usual, non-RPS scenario. We use data from the "peak target year" (e.g., 7% in 2012 for Massachusetts, 9% in 2010 for Minnesota, etc.) to compare most of the studies' projections because we believe it to be the most tractable and consistent method for comparing the long-term RPS impacts of studies that provide projected impacts in widely varying formats and timeframes. The direct cost impacts referred to here account for any reductions in wholesale electricity market prices that the studies may have modeled, but do not include any potential reductions in consumer natural gas bills.
[2] All cost figures in this report have been converted to 2003 dollars.

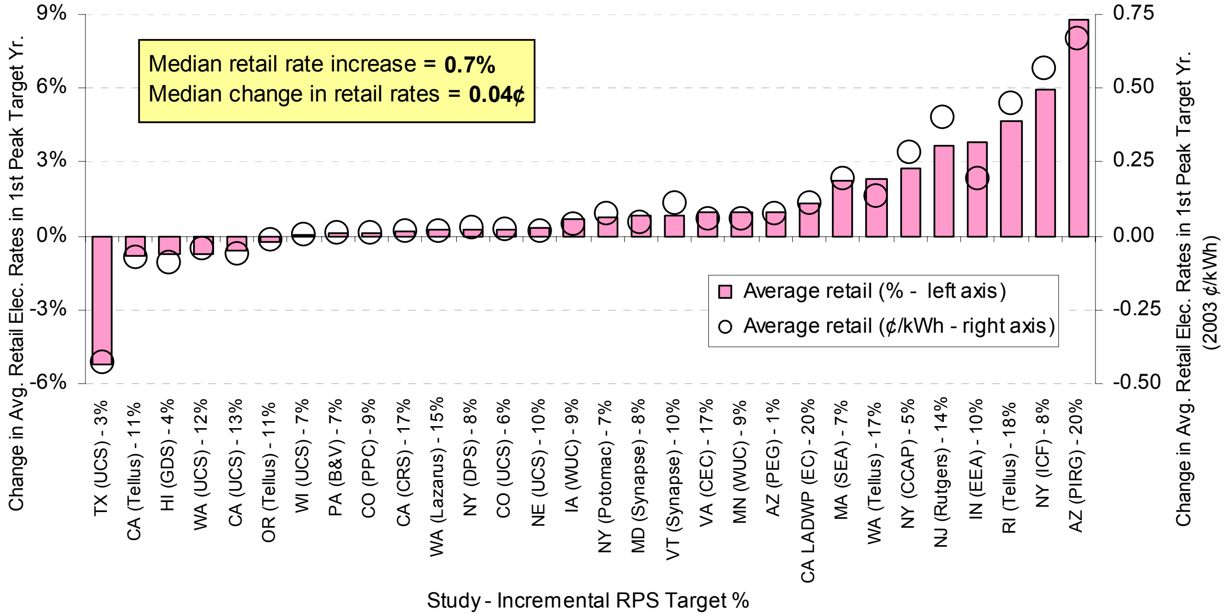


Figure ES - 1. Projected RPS Electricity Rate Impacts by Cost Study

Wind is expected to be the dominant technology in meeting RPS requirements. Figure ES - 2 presents the projected mix of new renewable generation used to meet the modeled RPS policies (for the 23 studies that forecast the renewable technology mix). The renewable generation mix is an input assumption to some studies and a model output to others. Perhaps not surprisingly, wind is expected to be the dominant technology, representing in aggregate 62% of incremental RPS generation across all of these studies combined. Projected wind development is particularly prevalent in the Midwest and Texas, accounting for 94% of expected incremental RPS generation in those states. Geothermal, which accounts for 18% of projected incremental generation across the studies, is a distant second, and almost all of the expected geothermal additions are from three California studies. Biomass co-firing and direct combustion account for approximately 8% of expected incremental generation, while hydro, landfill gas, and solar each comprises less than 4%.[3]

[3] These percentages are purely intended for illustrative purposes. They do not represent the overall RPS mix that would be developed if RPS policies were adopted in all of the states for which cost studies have been performed. Renewable energy deployment data are not available for all states, and multiple cost studies exist in some states, thereby "double counting" the impacts of those states' RPS policies on these percentage figures.

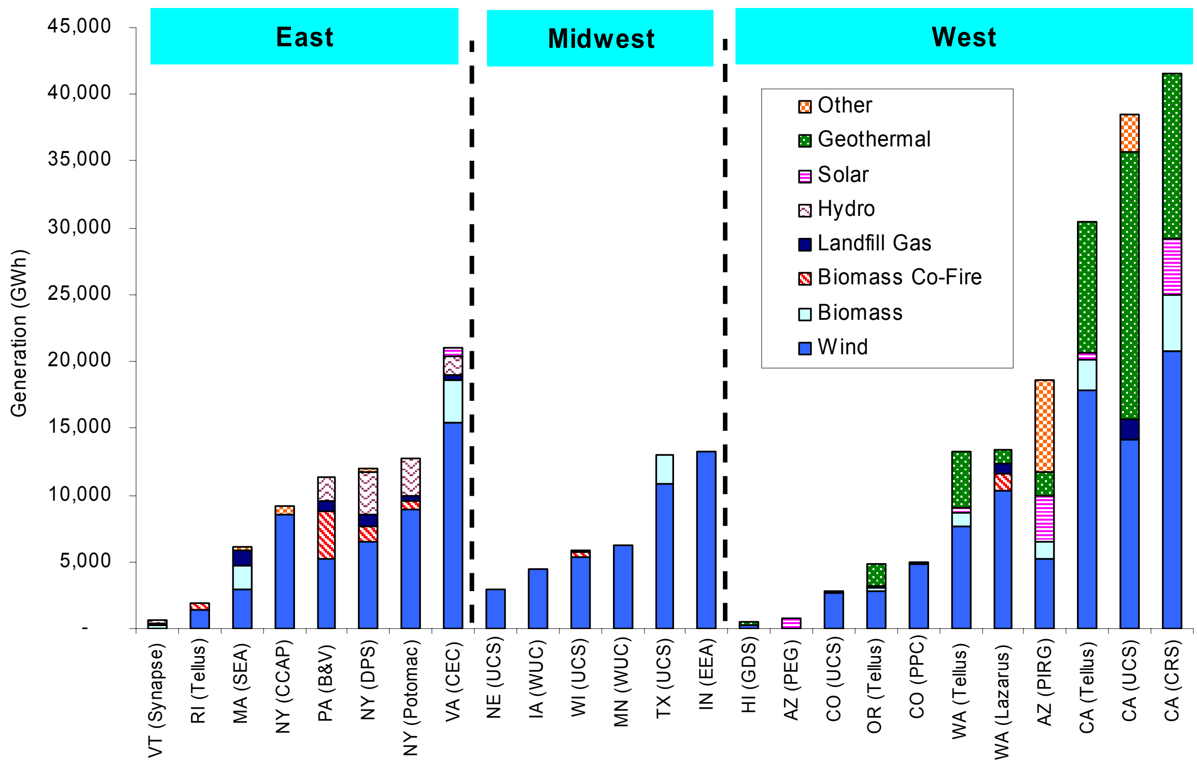


Figure ES - 2. Incremental Renewable Energy Deployment by Study and Technology

Scenario analyses reveal significant cost sensitivity to input parameters. The majority of the studies we reviewed include some form of scenario analysis using input assumptions that differ from those used in the base case. The most commonly modeled scenarios focus on the availability of the federal production tax credit, varying projections of renewable technology cost, fossil fuel price uncertainty, and wholesale market price uncertainty. The prevalence of these scenarios implies – but does not prove – that projected RPS costs are more likely to be sensitive to these particular factors than to others. Due to the wide range of scenarios modeled and the different assumptions used within each type of scenario, it is difficult to draw definitive conclusions about the relative impact of different cost drivers. In most cases, the residential electricity bill impacts of the scenarios analyzed by the studies – as measured by changes from the base case RPS – are less than one dollar per month. Though such changes are not overwhelming, it is important to recognize that the median *base-case* residential electricity bill impact among the studies in our sample is just $0.38 per month. Therefore, even a one dollar per month change from this base case is sizable in percentage terms, and demonstrates significant cost sensitivity to input parameters.

Some of the public benefits of RPS policies are still not well understood. An increasing number of studies are modeling macroeconomic or public benefits of RPS policies. Almost a third of the studies in our sample model the macroeconomic effects of RPS policies.[4] All of these studies predict some level of net employment gain, but the magnitude of this impact varies widely and appears to depend more strongly on the assumptions of the studies than on the

[4] However, our sample does not include RPS analyses that have focused exclusively on macroeconomic benefits.

amount of incremental renewable generation required to meet the modeled RPS policies. These assumptions include the different mixes of renewable technologies developed, the proportion of in-state versus out-of-state renewable project development and manufacturing, and the incorporation (or lack thereof) of energy bill impacts into the macroeconomic analysis. About a quarter of the studies in our sample also model the risk mitigation benefits of RPS generation, estimating a broad range of reductions in wholesale electricity and natural gas prices; still other studies evaluate the sensitivity of the projected cost of RPS policies to variations in the projected price of natural gas. Half of the studies we reviewed quantify potential environmental benefits, most commonly carbon dioxide (CO_2) emissions reductions. Most of these studies indicate that RPS generation is expected to displace CO_2 emissions at a rate that is, on average, slightly higher than that of a natural gas plant. Although the spread of projected CO_2 abatement costs across the studies is extremely broad, a majority of these studies project CO_2 reduction costs that fall within the range of the U.S. Energy Information Administration's (EIA) projections of carbon reduction costs under various regulatory regimes (Wiser and Bolinger 2004).

Analysis assumptions are likely as or more important than the choice of model. In the absence of a universally accepted methodology for analyzing RPS cost impacts, the studies in our sample employ a diverse array of modeling approaches, ranging from simple spreadsheet models to highly sophisticated integrated energy models. This diversity in modeling approaches may be due in part to regional differences in RPS policies and electricity markets, as different situations call for different modeling approaches. However, the limited budgets and short timeframes that typically apply to RPS cost studies are probably the more important determinants of the modeling approach chosen, as the sophistication and detail of the analysis is likely to be constrained by these limiting factors. Though more sophisticated models can account for interesting and potentially significant price feedbacks and may be better received by policymakers and RPS stakeholders, it is not entirely clear that such models necessarily improve predictive accuracy. Given the significant uncertainty surrounding numerous RPS cost factors, it is likely that the assumptions governing these factors, such as the natural gas price forecast and the presumed availability of the production tax credit, are as or more important than the type of model used.

Studies appear to have underestimated both renewable technology costs and avoided fuel costs. The vast majority of studies we reviewed appear to have underestimated two major RPS cost factors: wind power capital costs and natural gas prices. Since wind is expected to be the dominant contributor to RPS generation requirements, wind cost assumptions are critically important for estimating the cost impacts of RPS policies. Since the studies did not anticipate the sudden leap in wind costs over the past several years, the wind capital cost assumptions in most of the studies, which typically fall between $800-1300/kW in the 2005-2010 timeframe, are significantly below current costs (which are reportedly in the $1400-2000/kW range). This disparity between study expectations and current market reality suggests that (all else being equal) the actual cost impacts of state RPS policies may significantly exceed those estimated in our sample of studies, especially if higher wind costs persist. However, most, if not all, of the studies appear to have also substantially underestimated natural gas prices, which are perhaps the most important input to the avoided cost estimates of several studies.[5] Current natural gas prices (and near-term price expectations) are much higher than those assumed by the studies, as most of the studies rely on dated Energy Information Administration natural gas price forecasts projecting prices that are far lower than current price expectations. It is uncertain to what degree this apparent underestimate of natural gas prices will negate the effects of underestimating current wind costs; the uncertainties involved with predicting these two inputs highlight the importance of performing scenario analysis.

Conclusions

With few exceptions, the long-term electricity rate impacts of RPS policies are projected to be relatively modest. When these electricity cost impacts are combined with possible RPS-induced natural gas price reductions and corresponding gas bill savings, the overall cost impacts are even smaller.

The large diversity of modeling methodologies and assumptions used to estimate RPS costs demonstrates that RPS cost analysis is still an evolving process, and that a standard template has not yet emerged. Moreover, like most prospective analyses of electricity markets, RPS cost analysis is an inherently uncertain practice, highlighting the importance of evaluating the sensitivity of projected RPS costs to uncertain input parameters. Though this report focuses most heavily on RPS-induced rate impacts, an increasing number of studies are modeling the macroeconomic or other public benefits of RPS policies, either in addition to or exclusive of rate impacts.

RPS cost studies are becoming more sophisticated, but improvements are still possible. We identify a number of areas of possible improvement for future RPS cost studies:

- ***Improved treatment of transmission costs, integration costs, and capacity values:*** Transmission availability and transmission expansion costs have become among the most important barriers to renewable energy in many states, but these costs are often poorly understood and imprecisely modeled in RPS cost studies.[6] The capacity value of renewable energy (wind, in particular), as well as the cost of integrating renewable energy into larger electricity systems, are likewise emerging as potentially important variables, and studies analyzing RPS policies with relatively high incremental targets must be careful to properly account for these potential costs and impacts.

- ***More rigorous estimates of the future cost and performance of renewable technologies.*** As the renewable energy market continues to rapidly evolve and expand, the need for accurate, rigorous, and up-to-date estimates of renewable resource cost, performance, and potential is as acute as ever. Unfortunately, some of the most commonly used data sources for the cost and potential of renewable generation technologies are somewhat dated and arguably not up

[5] This is not true of studies that assume that avoided costs will be effectively determined by the cost of non-natural-gas generators (i.e., coal-fired generators), but most of the studies in our sample have explicitly or implicitly assumed that avoided costs will be primarily determined by the cost of natural gas-fired generation.
[6] The same criticism also often applies to some extent to cost evaluations of transmission expansion needed for conventional generation.

to the task. Developing better estimates of future renewable technology cost and performance would require time and resources that are beyond the scope of many RPS cost studies, and would probably be best managed by a government agency. The availability of such information would improve the credibility of RPS cost analysis and lend more weight to economic analysis of renewable technologies in general.

- ***Consideration of competing RPS requirements:*** As the number of states that have adopted RPS policies continues to grow, the available supply of renewable energy in regions with limited renewable potential (e.g., New England) may become more costly due to increased demand. Future cost studies would be well served to consider renewable demand from existing and potentially new RPS policies in neighboring states and regions and evaluate the potential effect of this demand on RPS rate impacts.

- ***Estimating the future price of natural gas:*** Where possible, base-case natural gas price forecasts should be benchmarked to then-current NYMEX futures prices (Bolinger et al. 2006). Furthermore, given fundamental uncertainty in future gas prices, a healthy range of alternative price forecasts should be considered through sensitivity analysis. To calculate the potential secondary impacts of increased renewable energy deployment on natural gas prices, either an integrated energy model or the simplified tool developed by Wiser et al. (2005) might be used.

- ***Evaluation of coal as the marginal price setter:*** With high natural gas prices, some states are shifting away from natural gas towards other resources, especially coal. A few of the RPS cost studies already assume that coal is the marginal fuel type that is offset by increased renewable generation, but most of the studies assume that natural gas will be the primary source of displaced electricity generation. New studies should more closely investigate the possibility that RPS generation may increasingly displace coal-fired and other non-gas-fired generation. Such a shift would likely reduce the importance of natural gas bill savings, but could also increase the importance of carbon emissions reductions.

- ***Greater use of scenario analysis:*** The inaccuracy of long-term fundamental gas price forecasts from the EIA and other private sector firms in recent years underscores the importance of using scenario analysis to bound possible outcomes. Not only is the future cost of conventional generation unknowable, renewable technologies themselves are experiencing rapid changes, both of which render the long-term impacts of RPS policies highly uncertain. Such uncertainty can be evaluated, to a degree, through greater use of scenario analysis. Some of the variables that may be most appropriate for scenario analysis include renewable technology potential and costs, future natural gas prices, the period of PTC extension, and the potential impact of future carbon regulations.

- ***Consideration of future carbon regulations:*** As some states and regions begin to implement carbon regulations, renewable generators may stand to benefit. It is also possible that federal carbon regulations will be developed within the time horizon of state RPS policies. Although these trends may significantly reduce the incremental cost of renewable generation required by RPS policies, the risk of future carbon regulation has only been modeled by four of the studies in our sample. In future studies, we recommend that the risk of future carbon regulations be explicitly considered, at a minimum through scenario analysis.

- ***Accurate representation of RPS market structure:*** In some regions of the country, RPS compliance strategies based on short-term markets for renewable energy credits (RECs) have led to unexpected cost impacts. For example, in Massachusetts, a lack of long-term contracts to support new renewable development (coupled with high demand for RECs and difficulties in siting and permitting) has resulted in ratepayer costs that are substantially higher than anticipated. RPS cost studies should seek to adopt modeling approaches that are consistent with probable RPS market structures.

- ***More robust treatment of public benefits:*** Though an increasing number of studies have modeled macroeconomic benefits, the assumptions driving these analyses are often inconsistent, and the wide range of results may detract from the credibility of such studies. More work is needed to identify the most feasible and defensible assumptions governing the public benefits of renewable energy, including the fossil fuel hedge value of renewable energy and the benefits of reduced carbon emissions, in addition to employment and economic development impacts.

Actual RPS costs may differ from those estimated in the RPS cost studies. The improvements listed above, if adopted, should lead to more accurate and realistic projections of the costs and benefits of state RPS policies in the future. In the meantime, it is difficult to assess whether the RPS impact studies reviewed in this report present overly optimistic or overly conservative estimates of future costs. Some of the assumptions in the RPS cost studies that may result in an underestimation of actual RPS costs include:

- Wind capital cost assumptions that appear too low in many cases, given recent increases in wind costs;
- Transmission and integration costs that are not fully considered in some instances;
- Use of an "average cost" approach to estimate incremental renewable generation costs in some situations when a marginal-cost-based approach may be more appropriate;
- Lack of full consideration for the potential demand for renewable energy from other sources (such as demand from other state RPS policies);
- Increased likelihood that coal-fired generation will set wholesale market prices in some regions which, in the absence of carbon regulations, may make renewable generation less economic than when renewable energy is presumed to compete with natural gas; and,
- Expectations in some cases that the federal production tax credit (PTC) will be available indefinitely, which may be overly optimistic given the political uncertainty affecting PTC extension.

Conversely, a number of other cost study assumptions may result in an overestimation of actual RPS costs, including:

- Reliance on natural gas price forecasts that are almost universally substantially below current price expectations;

- Secondary natural gas and/or wholesale electric price reductions that have not been modeled in many of the studies;
- The potential for future carbon regulations, which are ignored in most of the studies in our sample; and
- Expectations in many cases that the PTC will only be available for either a very limited period or not at all, which may be overly conservative given the recent two-year extension of the PTC and the possibility for longer-term extension.

As states accumulate more empirical experience with actual RPS policies, future analyses should benchmark the cost projections from RPS cost studies against actual realized cost impacts as a way to both inform future RPS modeling efforts and better weigh the potential costs and benefits of state RPS policies.

1. Introduction

Renewables portfolio standards (RPS) require that a minimum amount of renewable energy is included in each retail electricity supplier's portfolio of electricity resources. They do so by establishing numeric targets for renewable energy supply, which generally increase over time. To date, 21 states in the U.S., along with the District of Columbia, have adopted such standards (Figure 1). Additional states, such as Illinois and Vermont, have established voluntary standards, while still others are considering enacting obligatory RPS policies. RPS policies have also been developed in several other countries, and have been considered (but not adopted) by the U.S. Congress.

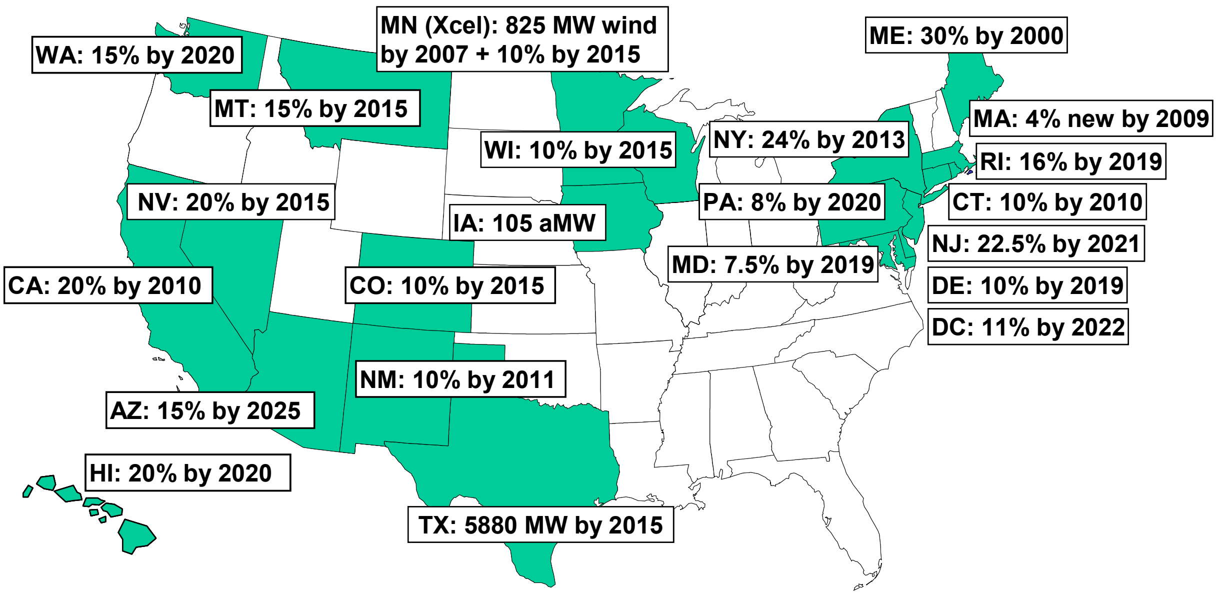


Figure 1. State RPS Policies Currently in Place[7]

A well-designed RPS should generally encourage competition among renewable developers and provide incentives to electricity suppliers to meet their renewable purchase obligations in a least-cost fashion. In part to accommodate diverse goals and regional differences, however, state RPS policies differ in their design. The definition of eligible renewable projects and the amount of renewable energy that is required varies. In many – but not all – jurisdictions, electricity suppliers can meet their RPS obligations through the use of tradable renewable energy certificates (RECs); in theory, the use of RECs increases compliance flexibility and may therefore reduce overall compliance costs. RPS policies in some states provide for resource tiers or credit multipliers, which are designed to promote diversity among renewable technologies.[8]

[7] Illinois and Vermont have established voluntary RPS policies. In addition to Xcel's renewable energy mandate, Minnesota also has a non-mandated renewable energy objective that requires the state's other electric utilities to make a good faith effort to achieve RPS targets. Maine also recently adopted a goal that "new" renewable energy comprise 10% of the state's electricity supply on a capacity basis.

[8] With the resource tier approach, higher cost or higher priority technologies are grouped together in a compliance tier, so that they are not competing with lower cost or lower priority technologies, which comprise a second tier.

State RPS policies also vary in their scope of application (e.g., whether publicly owned utilities are required to comply), and in their use of compliance flexibility and non-compliance penalties.[9]

Opponents of RPS policies frequently claim that these policies are not worth implementing because the incremental costs of renewable energy may lead to substantial increases in electricity prices. RPS proponents often counter these claims by presenting evidence of the modest cost of renewable energy resources and touting the macroeconomic and social benefits of RPS policies. In many states, RPS stakeholders – often proponents or neutral parties, but possibly opponents as well – have authored or commissioned studies to analyze the potential costs and benefits of such policies.

This report summarizes the results and methodologies of 28 RPS cost-impact analyses completed since 1998 in the United States. Though a number of additional national- and regional-level cost-impact studies have also been performed, we limit our survey to state- or utility-level analyses to reflect the present reality in which no national or regional-level RPS policy exists in the United States. Because our primary aim is to compare studies that report the projected impacts of RPS policies on retail electricity rates, we also exclude RPS analyses that do not report such impacts but that instead focus exclusively or primarily on projections of macroeconomic effects (e.g., effects on employment and gross state output).[10] We similarly exclude studies that model RPS policies as part of a larger portfolio of climate change or clean energy policies, unless RPS-specific costs are provided.[11]

The primary purpose of this report is to summarize, in as consistent a fashion as possible, the results of these 28 cost-impact analyses, including both the projected costs and benefits of state- and utility-level RPS programs. In so doing, we hope to illustrate the expected bounds of likely impacts. We also highlight and, in some cases, critique the various methods used by these studies, with a goal of identifying possible areas of improvement for future RPS analyses.[12]

The remainder of this report is organized as follows:

- ***Section 2*** presents a general overview of the 28 RPS cost studies included in our analysis.
- ***Section 3*** provides a summary and comparison of the renewable resource mix and direct cost impacts projected by the RPS cost studies.
- ***Section 4*** identifies any alternative scenarios that are analyzed by the RPS cost studies, and presents the anticipated costs associated with those scenarios.

Credit multipliers provide additional RPS compliance “credit” for certain types of renewable generation, e.g. PV technology or renewable energy generated in-state.

[9] For an international review of early experience with RPS policies, see van der Linden et al. (2005). For a somewhat dated review of U.S. experience, see Wiser et al. (2004). See Rader and Hempling (2001) for a detailed but also dated discussion of RPS design issues.

[10] Examples of such analyses include Bournakis et al. (2005), Perryman (2005), and Virtus (2002).

[11] For example, we exclude the Connecticut Climate Change Action Plan, which models a state RPS as one of several climate change mitigation policies but does not identify RPS-specific costs.

[12] We do not compare the *projected* costs and benefits of RPS policies with the *realized* costs and benefits of RPS policies that are now operating. We leave that important comparison for future work.

- ***Section 5*** summarizes the projected benefits of the RPS policies, and compares the expected employment impacts, risk mitigation benefits, and CO_2 emissions reductions that are quantified in the studies.
- ***Section 6*** compares the general modeling approaches used by the RPS cost studies and includes a discussion of how the studies have represented RPS market structure.
- ***Section 7*** describes the methodologies and assumptions that the RPS cost studies have used in modeling renewable resource potential and cost.
- ***Section 8*** describes the methodologies and assumptions that the RPS cost studies have used in modeling avoided cost.
- ***Section 9*** summarizes our key findings and highlights some possible areas of improvement for future RPS cost studies.

2. Overview of RPS Cost Analyses

2.1 Study Identification

Eighteen states, covering most regions of the country, are represented in the 28 RPS cost studies we surveyed (see Figure 2 below and Table 1 on the following page. A complete bibliography of the studies is provided in Appendix A. Not surprisingly, most of these cost-impact studies analyze RPS policies in states that now have RPS programs in place. Only five of the reviewed studies (in Indiana, Oregon, Nebraska, Virginia, and Vermont) apply to states that have not yet adopted a mandatory RPS.

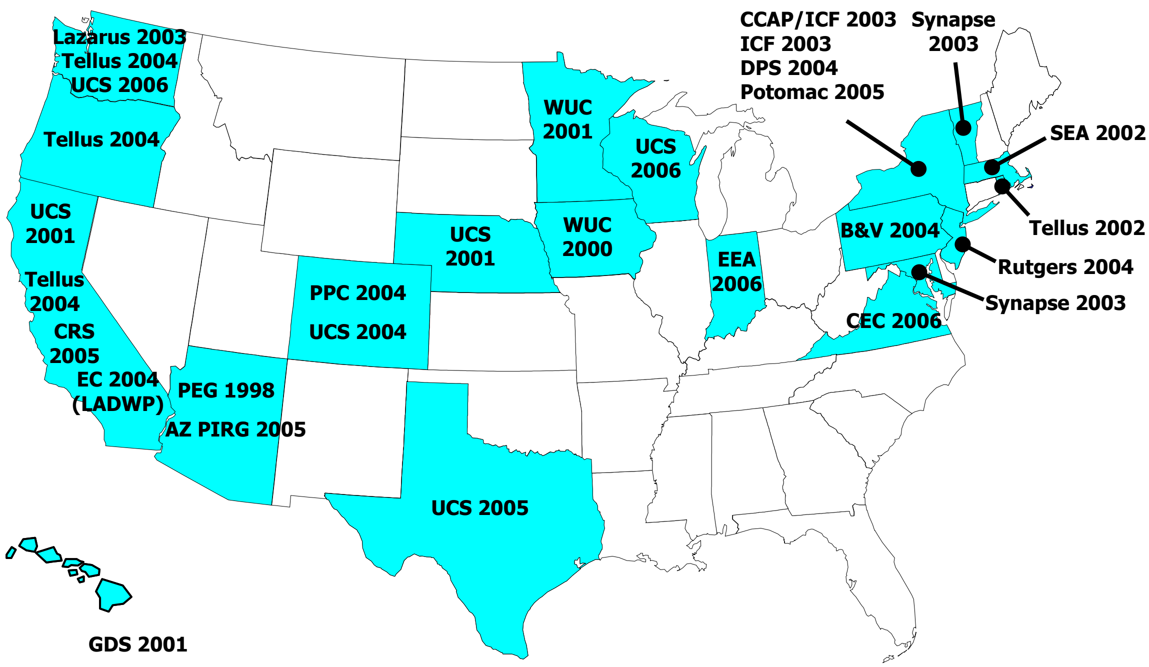


Figure 2. RPS Cost-Impact Studies Included in Report Scope[13]

[13] Tellus (2004) is a single study that models RPS policies for Washington, Oregon, and California. Because results are presented for each state individually, we include this study in our sample.

Table 1. List of Reviewed RPS Cost-Impact Studies

State	Principal Author(s)	Year	Title
AZ	AZ PIRG Education Fund (AZ PIRG)	2005	Renewing Arizona's Economy: The Clean Path to Jobs and Economic Growth
AZ	Pacific Energy Group (PEG)	1998	Solar Portfolio Standard Analysis
CA	Union of Concerned Scientists (UCS)	2001	Powering Ahead: A New Standard for Clean Energy and Stable Prices in California
CA/OR/ WA	Tellus	2004	Turning the Corner on Global Warming Emissions: An Analysis of Ten Strategies for California, Oregon, and Washington
CA (LADWP)	Environment California (EC)	2004	Clean and Affordable Power: Updated Cost Analysis for Meeting a 20% Renewables Portfolio Standard by 2017 at LADWP
CA	Center for Resource Solutions	2005	Achieving a 33% Renewable Energy Target
CO	Public Policy Consulting (PPC)	2004	The Impact of the Renewable Energy Standard in Amendment 37 on Electric Rates in Colorado
CO	UCS	2004	The Colorado Renewable Energy Standard Ballot Initiative: Impact on Jobs and the Economy
HI	GDS Associates (GDS)	2001	Analysis of Renewable Portfolio Standard Options for Hawaii
IA	Wind Utility Consulting (WUC)	2000	Projected Impact of a Renewable Portfolio Standard on Iowa's Electricity Prices
IN	Engineering Economic Associates (EEA)	2006	Rate Impact of a Renewable Electricity Standard in Indiana
MA	Sustainable Energy Advantage (SEA) & La Capra	2002	Massachusetts RPS: 2002 Cost Analysis Update – Sensitivity Analysis
MD	Synapse Energy Economics	2003	The Maryland Renewable Portfolio Standard: An Assessment of Potential Cost Impacts
MN	Wind Utility Consulting (WUC)	2001	Projected Impact of a Renewable Portfolio Standard on Minnesota's Electricity Prices
NE	UCS	2001	Strong Winds: Opportunities for Rural Economic Development Blow Across Nebraska
NJ	Rutgers CEEEP	2004	Economic Impact Analysis of New Jersey's Proposed 20% Renewable Portfolio Standard
NY	Center for Clean Air Policy (CCAP)/ICF	2003	Recommendations to Governor Pataki for Reducing New York State Greenhouse Gas Emissions
NY	ICF Consulting	2003	Report of Initial Analysis of Proposed New York RPS
NY	NY Department of Public Service (DPS)	2004	Renewables Portfolio Standard Order Cost Analysis
NY	Potomac	2005	Estimated Market Effects of the New York Renewable Portfolio Standard
PA	Black & Veatch (B&V)	2004	Economic Impact of Renewable Energy in Pennsylvania
RI	Tellus	2002	Rhode Island RPS Modeling
TX	UCS	2005	Increasing the Texas Renewable Energy Standard: Economic and Employment Benefits
VA	Clean Energy Commercialization (CEC)	2005	A Portfolio-Risk Analysis of Electricity Supply Options in the Commonwealth of Virginia
VT	Synapse	2003	Potential Cost Impacts of a Vermont Renewable Energy Portfolio Standard
WA	Lazarus, Lazar, Hammerschlag	2003	Economics of a Washington Energy Portfolio Standard: Effects on Ratepayers
WA	UCS	2006	The Washington Clean Energy Initiative: Effects of I-937 on Consumers, Jobs and the Economy
WI	UCS	2006	A Study to Evaluate the Impacts of Increasing Wisconsin's RPS

2.2 Design of RPS Policies in Study Sample

The publication of most of these studies was timed to coincide with RPS legislation that had been proposed or implemented, and many studies evaluate RPS policies designed as proposed or implemented through that legislation. Less frequently, some studies advance their own proposals for RPS legislation. Twenty-one of the 28 studies have been published since 2003, reflecting the recent surge in state RPS adoption. Because some of the studies analyze RPS proposals that were later substantially modified or never adopted, the RPS design that each study analyzes does not necessarily reflect the policy that was eventually adopted (if a policy was adopted at all). A few of the studies have updated their original analysis to more accurately reflect the RPS design that was ultimately adopted; in these instances, we include only the quantitative results from the updated analysis, though we sometimes describe qualitative aspects of the original studies.

As one might expect, the RPS policies modeled by these studies differ substantially with respect to structure, design, and quantitative target level. Table 2 briefly summarizes some of the most pertinent details of the RPS policy designs that are modeled by the cost studies in our review.[14] Table 2 primarily identifies the "base-case" RPS policies analyzed in each study; many of the studies evaluate multiple RPS designs as alternative cases, and these are discussed in Section 4. A number of the cost studies do not explicitly identify a "base-case" scenario; Appendix B identifies these studies and our rationale for choosing a base-case scenario in each instance.

For the purposes of the table, and subsequent analysis, we define the "incremental RPS target" as the incremental amount of *new* renewable generation needed to achieve the "overall RPS target," taking into consideration the fact that in some cases *existing* renewable generation is eligible to help meet the overall RPS target.[15] In other words, the incremental target is our estimate of the difference between the overall RPS target and the existing baseline renewable generation level.[16] A few studies project some level of new renewable generation in the reference case scenario without the application of the RPS (i.e., CA/OR/WA (Tellus), Texas (UCS), Virginia (CEC), and Washington (UCS)).[17] In these cases, we allocate this new renewable generation to the existing baseline renewable generation level when estimating the incremental target, thereby "depressing" the incremental target.[18] This approach is used because in evaluating the costs and benefits of state RPS policies, these few studies compare the modeling output of the RPS scenario relative to the reference-case scenario, which also includes some level of renewables development. Because many of the other studies do not take a similar approach – effectively

[14] For more information on the RPS design modeled by each individual study, readers should refer to the original cost-impact studies cited in Table 1. Appendix A contains URLs for those studies that are available online.

[15] A "new" renewable resource is typically defined as a facility that comes online after a specific date. This date is generally set to be a few months to a few years prior to when RPS requirements go into effect.

[16] In states that do not allow for RPS participation by existing resources, the incremental RPS target is equal to the overall target. We also assume the two target levels to be equal when existing resources are eligible, but the baseline level of existing renewable generation is negligible.

[17] In addition, Rhode Island (Tellus) includes a negligible amount of increased generation from existing renewable plants in the study's reference case.

[18] Were we not to allocate this new renewable generation to the baseline, then the incremental targets would be 6.3% for Texas (UCS), 21.4% for CA (Tellus), 15.7% for OR (Tellus), and 18.5% for WA (Tellus). In the case of CA (Tellus), most of the new renewable generation in the reference case is due to an existing 20% by 2017 RPS (as compared to the policy case RPS, which calls for 33% renewable generation by 2020).

assuming that no renewable generation will be developed absent the RPS – this does create some minor inconsistency in study comparisons.

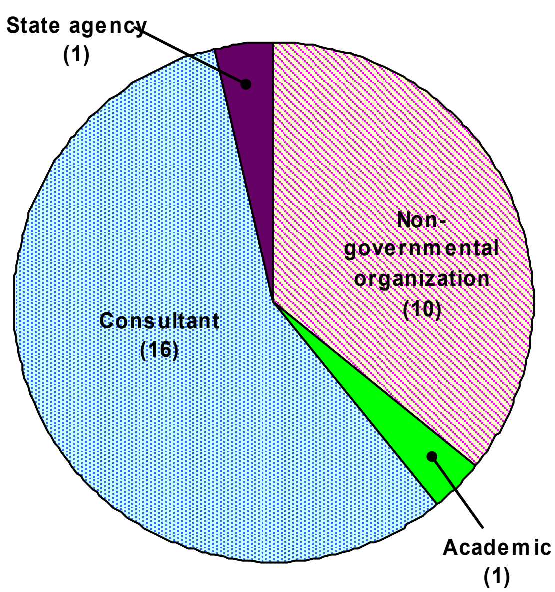
Table 2. RPS Policies as Modeled by RPS Cost Studies

Study	Overall RPS Target	Incremental RPS Target	Year Target is Reached	Additional Notes
AZ (PIRG)	20%	20%	2020	
AZ (PEG)	1%	1%	2002	Only eligible technology is solar
CA (CRS)	33%	16.7%	2020	Target percentages are measured with respect to the load of investor-owned utilities
CA (UCS)	20%	13.2%	2010	
CA (Tellus)	33%	11.2%	2020	Incremental to existing 20% RPS
CA LADWP (EC)	20%	20%	2017	2004 update to original 2003 study; RPS applies only to the Los Angeles Department of Water and Power (LADWP), which represents approx. 10% of statewide load
CO (PPC)	10%	6.5%	2015	Update to earlier study; includes credit multiplier for in-state resources and 0.4% set-aside for solar
CO (UCS)	10%	6.3%	2015	Includes credit multiplier for in-state resources and 0.4% set-aside for solar
HI (GDS)	9.5%	3.8%	2010	Also models a 10.5% RPS target
IA (WUC)	10%	8.6%	2015	
IN (EEA)	10%	10%	2017	
MA (SEA)	7%	7%	2012	2002 Update to original 2000 study
MD (Synapse)	7.5%	7.5%	2013	
MN (WUC)	9%	9%	2010	
NE (UCS)	10%	10%	2012	
NJ (Rutgers)	20%	13.5%	2020	Incremental to existing 6.5% RPS; includes incremental solar tier of 0.64%.
NY (CCAP)	8%	5.2%	2012	
NY (ICF)	25%	8%	2013	Resource tiers: at least 0.4% fuel cells and 0.4% solar PV
NY (DPS)	25%	7.7%	2013	2004 update to original 2003 and 2004 studies; includes 0.15% customer-sited tier
NY (Potomac)	25%	6.9%	2013	Includes 0.15% customer-site resource tier
OR (Tellus)	20%	10.6%	2020	
PA (B&V)	10%	7.2%	2020	Update to earlier study; two-tiered portfolio standard, but we only include results from Tier I: the renewable energy tier
RI (Tellus)	20%	18.4%	2020	Also models 10% and 15% targets
TX (UCS)	10,000 MW	2.7%	2025	Also models 20% by 2020 target
VA (CEC)	20%	16.9%	2015	Also models 15% target
VT (Synapse)	10%	10%	2015	Also models 5% and 20% targets
WA (Lazarus)	15%	15%	2023	RPS includes efficiency, but 15% targets identified here only reflect renewables
WA (UCS)	15%	11.9%	2020	RPS includes efficiency, but we only include results attributable to the renewable additions
WA (Tellus)	20%	16.6%	2020	
WI (UCS)	10%	7.2%	2015	2006 update to original 2003 study

A few of the studies evaluate RPS policies with multiple resource tiers. These resource tiers may include energy efficiency measures, as well as resources that are not generally considered to be renewable. For example, Tier II of Pennsylvania's "Advanced Energy Portfolio Standard" includes waste coal facilities, integrated gasification combined cycle plants, and measures that reduce greenhouse gas emissions. In this case, we only report and evaluate the impacts of Tier I of the energy standard, which includes renewable resources. Similarly, when energy efficiency is eligible, we isolate the cost impacts of the renewable resources to facilitate comparability with the other RPS studies. In several other cases, RPS policy designs include solar or customer-sited distributed generation tiers; studies that include such tiers are identified in Table 2.

2.3 Primary Authorship and Funding Source of Studies in Sample

Figure 3 identifies the types of organizations that have served as the primary authors and funding sources of the RPS cost-impact studies that we reviewed. The vast majority of studies have been authored by consultants (over 55%) and non-governmental organizations (NGOs, roughly 35%). Funding has predominantly come from non-profit foundations and interest groups (representing over 55% of primary funding sources) and state utility commissions or energy agencies (representing roughly 25% of primary funding sources).[19]



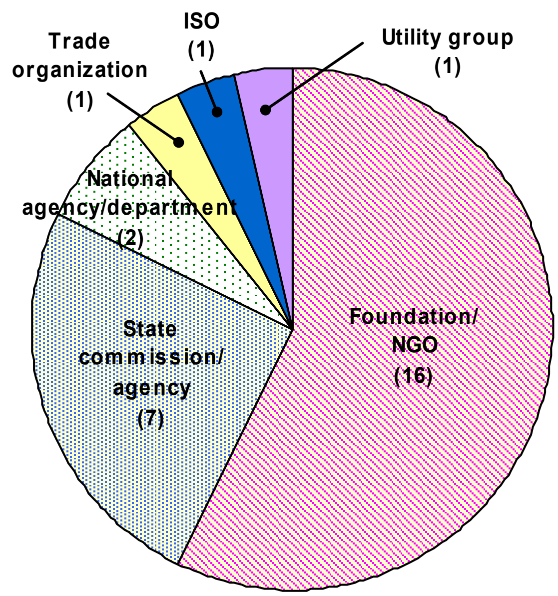


Figure 3. Primary Authorship and Funding Source of RPS Cost Studies

Some of these studies were conducted as part of an extended public process. These reports typically involved the participation and input of diverse stakeholder groups, and in some cases were part of a larger, state-sponsored regulatory proceeding that allowed for public comments on draft versions of the study. Most of the studies in our sample, however, were not distributed for

[19] When studies have been funded by multiple entities, we only identify the primary funding source.

broad public review prior to publication. It is also noteworthy that many of the reviewed studies have been produced by organizations and authors that are strongly supportive of RPS policies, whereas few of the studies have been funded or conducted by RPS opponents. This report does not attempt to account for any potential bias that might result from the type of study author or funding source, though it does scrutinize the studies' methods and assumptions more generally.

3. Projected Renewable Resource Mix and Direct Costs

This section summarizes two of the most important outputs of the RPS cost-impact studies: the projected impacts of RPS policies on renewable energy deployment by technology and on the direct costs of that deployment. In the former case, we present the expected amount of generation from each renewable technology used to meet the RPS policies. In the latter case, we define direct costs to include the impact of renewables deployment on retail electricity rates and bills. These direct costs do not include the effect of increased renewable generation on the price of input fuels such as natural gas, which may then generate consumer savings outside of the electricity sector (this potential impact is covered in Section 5). Direct costs do, however, include wholesale electricity price reductions, including any electricity price reduction caused by lower natural gas prices; these impacts are included as direct effects because they influence consumer electricity bills. We focus here on impacts in the base-case RPS scenario; the results of alternative scenarios are identified here, but are discussed in more depth in Section 4.[20] Here, and elsewhere in the report, we ignore the social costs of RPS policies and focus exclusively on retail cost impact projections, since the studies themselves are focused on consumer, and not social, costs.[21]

3.1 Methodology for Comparing Results from Multiple Studies

The studies in our sample present projected RPS costs in many different ways. Though most studies report expected retail rate impacts, some studies only report changes in electricity sector generation (i.e. utility) costs. In addition, the studies use different units to convey cost results, including percentage change in costs (either on a retail- or generation-cost basis), total incremental system costs in dollars, changes to retail rates in cents per kilowatt-hour (kWh), changes to monthly electricity bills, and renewable energy certificate (REC) prices.

Developing a consistent set of metrics for comparing cost projections across studies is therefore necessary. To do so, we compare cost projections using two metrics that are easily understood and, where necessary, are readily converted from other data: (1) percentage changes in retail electricity rates, and (2) monthly electricity bill impacts for a typical residential household. The specific approaches that we used to convert cost data to these metrics are described in Appendix B. To further facilitate comparisons, all cost data have been converted to real 2003 dollars.

It is also difficult to create a method for comparing results from different time periods. Each study uses a different timeframe for its analysis.[22] The studies also report expected costs using a

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[20] We use the term "base case" to represent the baseline RPS scenario (as compared to the alternative RPS scenarios described in more depth in Section 4), while we use the term "reference case" to refer to the business-as-usual, non-RPS scenario.

[21] Though social costs may be more important from a strictly economic perspective, electricity market analyses often emphasize consumer cost impacts. Though these cost impacts may sometimes represent wealth transfers rather than true social costs, consumer cost projections are likely to be more relevant to most RPS stakeholders than are expected costs to society that ignore wealth transfers.

[22] For instance, the New York (DPS) study reports cost and renewable generation results for the 2006-2013 period, which coincides with the time interval during which the New York RPS requirements take effect. In contrast, the Colorado (PPC) study reports cost and renewable generation results for the 2005-2024 period, which is longer than the RPS implementation period of 2006-2015.

variety of different time horizons; they may report annual costs, costs averaged over a given timeframe, and/or the present or net present value of RPS-induced costs. The use of averaged data or individual "snapshot" years also complicates comparisons. More generally, comparing results from studies that themselves have been conducted over a span of several years is potentially problematic because underlying conditions may have changed over this period. Perhaps most obviously, natural gas prices (and price expectations) are much higher today than they were in years past, so an RPS study conducted several years ago would naturally yield different results than one conducted in the same manner today.

Given these challenges, complete comparability across all of the studies in our sample is simply not possible. Nonetheless, we temporally normalize the results from the different studies by presenting results from the first year that each RPS reaches its ultimate target level. For New York, we present results for 2013, when the RPS first reaches its ultimate percentage target level of 25%. For Colorado, we document results for 2015, when that state's RPS first reaches its ultimate percentage target of 10%.[23] (Note that the absolute amount of renewable energy may increase somewhat after the RPS target initially reaches its percentage peak due to load growth, even if the percentage itself then remains constant).

Though an imperfect metric for characterizing the full trajectory of cost impacts and renewable resource projections within each study, using the results from the initial peak year is a tractable and consistent method for comparing the projected impacts across studies with very different timeframes, especially considering the data limitations of the reviewed studies. The projected costs of state RPS policies in these initial peak target years tend to be the highest or close-to-highest of the cost impacts from all of the years that are modeled, allowing us to be conservative in reporting expected costs (i.e., to avoid under-representing the potential long-term costs of RPS policies).[24] Presenting data from the initial peak target year is also advantageous because the majority of the RPS cost studies provide data for that year.[25]

3.2 Projected Renewable Resource Mix: Base-Case Results

Though most of the studies in our sample are focused on cost impacts, the majority (23 of 28 studies) also forecast the mix of renewable technologies most likely to be used to meet RPS requirements (typically assuming that the least-cost renewable resources are selected before the more expensive ones). Figure 4 and Figure 5 present the projected mix of new renewable generation used to meet the modeled RPS policies.[26] (For a complete list of technologies modeled by the cost studies, please see Section 7.1.)

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[23] Due to data limitations, we were required to allow a few exceptions to this rule. Because Arizona (PEG) does not provide annual cost data, we use average 1998-2030 data as a proxy for long-term rate impacts. Iowa (WUC) provides only averaged data, so we use data averaged over 2005-2014 We interpolate between 2010 and 2015 data from New York (CCAP) to approximate estimates for 2012 (the initial peak target year of the RPS policy modeled in the study).

[24] Most cost projections indicate that RPS-induced rate impacts will decrease following the initial peak target year, sometimes by a substantial amount. Several factors may cause this result, but perhaps of most importance is the fact that the studies assume continued upward movement in the expected cost of fossil generation.

[25] It would have been far more difficult, for instance, to compare average cost impacts from the reviewed studies, because many of the studies do not include sufficient data to enable such a comparison.

[26] Again, for consistency the data are taken from the first year in which each modeled RPS reaches its ultimate target. Here and elsewhere in this report, results from Rhode Island (Tellus) reflect the impacts of RPS policies in

Perhaps not surprisingly, wind is expected to be the dominant technology, representing 62% of incremental RPS generation across all of the studies combined. Projected wind deployment is particularly prevalent in the Midwest and Texas, accounting for 94% of projected incremental RPS generation in those states. Geothermal, which accounts for 18% of projected incremental generation across the studies, is a distant second, and almost all of the expected geothermal additions are from the two California studies. Biomass co-firing and direct combustion account for approximately 8% of expected incremental RPS generation, while hydro, landfill gas, and solar each comprise less than 4%.[27]

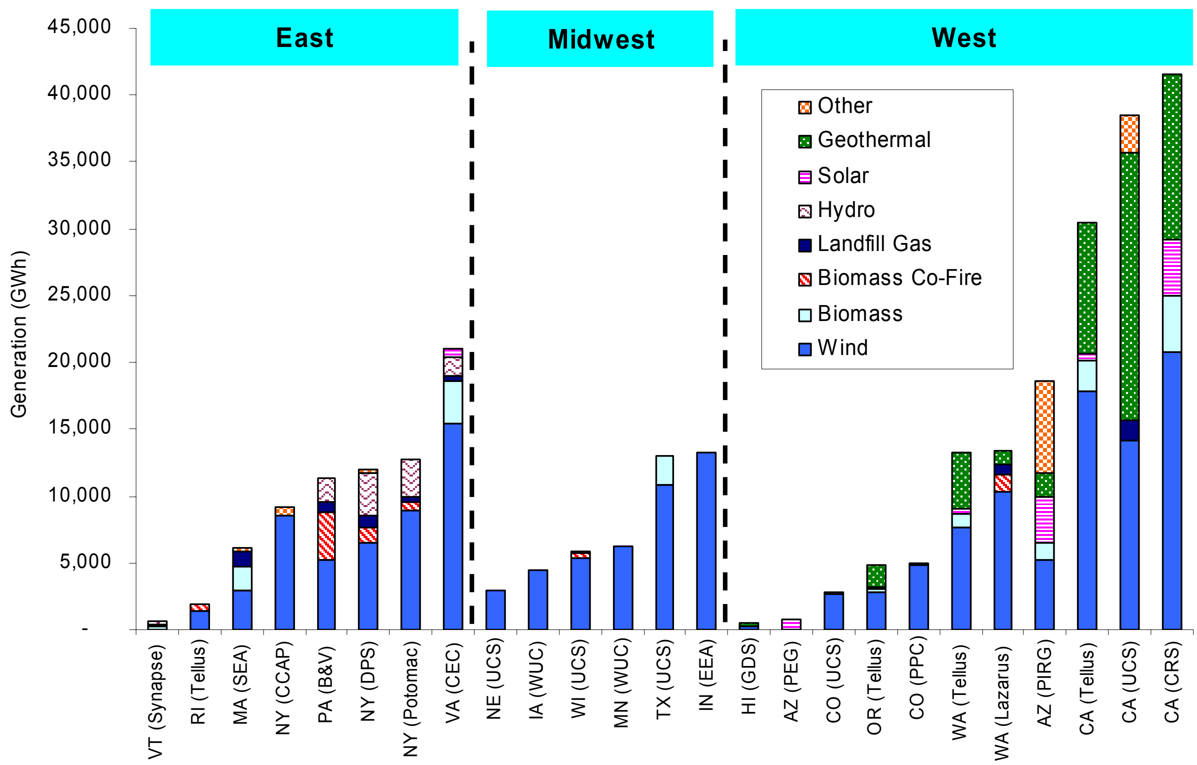

Figure 4. Incremental Renewable Energy Deployment by Study and Technology

Connecticut and Massachusetts as well as in Rhode Island. These impacts are apportioned to Rhode Island based on the state's contribution to demand for new renewable generation in the region. Please refer to the study for more detail on its modeling assumptions.

[27] These percentages are purely intended for illustrative purposes. They do not represent the overall RPS mix that would be developed if RPS policies were adopted in all of the states for which cost studies have been performed. Renewable energy deployment data are not available for all states, and multiple cost studies exist in some states, thereby "double counting" the impacts of those states' RPS policies on these percentage figures.

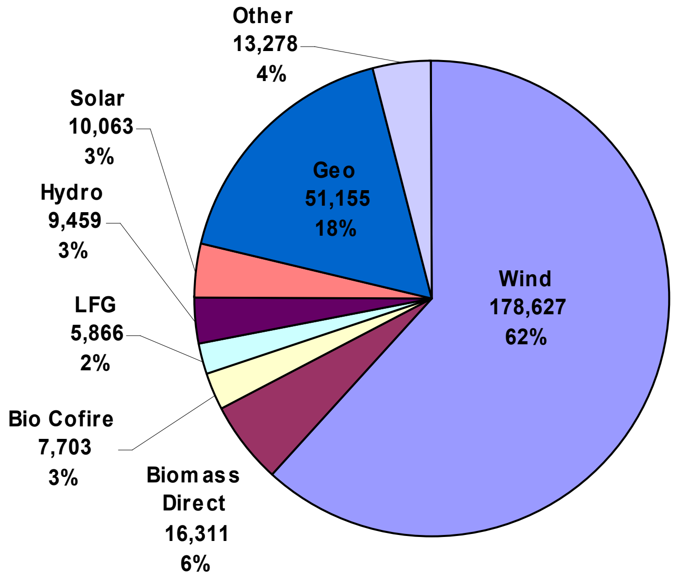

Figure 5. Mix of Incremental Renewable Generation from All Studies Combined (GWh, %)

Although not evident by the figures, it is worth mentioning that some studies treat the specific mix of renewable energy resources as an input to their cost estimation model, whereas in other studies the mix of renewable resources is a model output. When treated as an input, the renewable energy mix is typically crudely estimated according to the cost study author's knowledge of the situation in the state(s) being modeled. When treated as an output, renewable energy deployment is usually estimated by constructing an aggregate renewable resource supply curve, with the RPS target level determining which generators in the supply curve are "selected" in a given year. The methodologies and assumptions governing renewable resource estimates are discussed in greater detail in Section 7.2.

3.3 Direct Cost Impacts: Base-Case Results

Figure 6 presents the distribution of expected retail electricity rate impacts from the studies in our sample, again focusing on the initial peak target year of each study.[28] On the whole, RPS-induced rate impacts are typically projected to be relatively modest. More than half of the reviewed studies report base-case rate increases of between 0% and 1%. Six studies project that electricity consumers will experience cost *savings* as a result of the RPS policies being modeled, at least in the base-case scenario. On the other extreme, nine studies predict rate increases above 1%, and two of these studies predict rate increases of more than 5%.

[28] The number of studies in Figure 6 is higher than 26 (the number of studies in our review) because the individual state results from CA/OR/WA (Tellus) are shown separately.

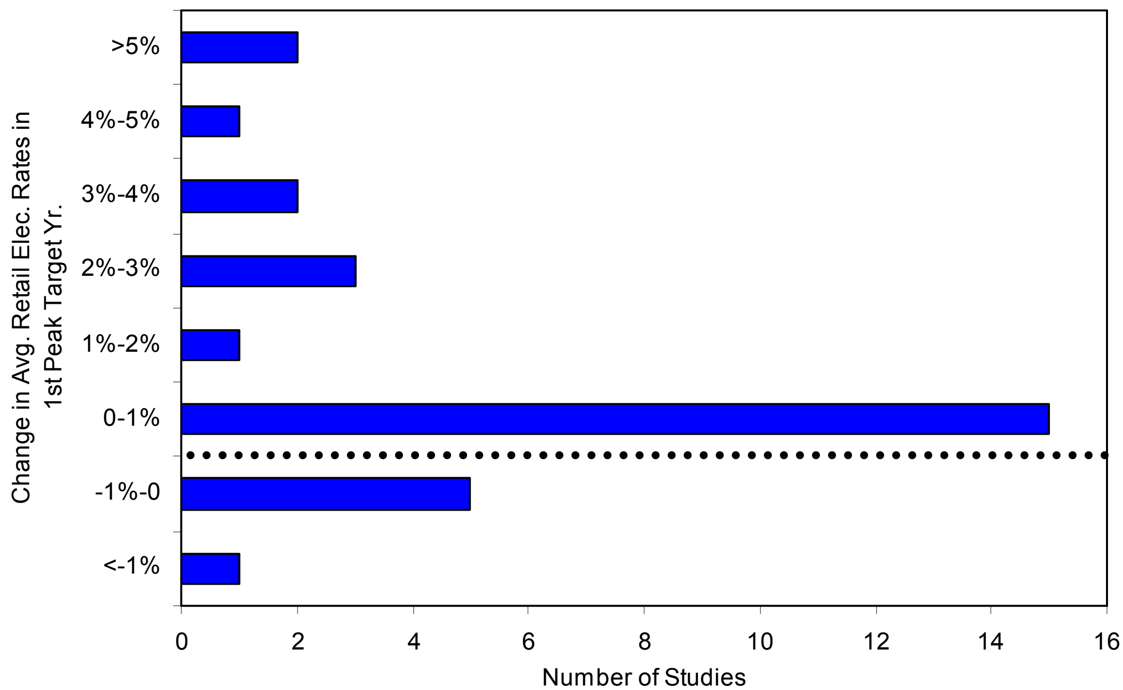

Figure 6. Distribution of Base-Case Impacts on Average Retail Electricity Rates

Figure 7 summarizes projected electricity rate impacts in percentage and ¢/kWh terms, for each individual RPS cost study (again, focusing on the base-case scenario). Among our sample, the median projected increase in retail electricity rates is 0.7%, or 0.04 ¢/kWh. Relatively few studies predict increases in retail electricity rates that exceed 0.25 ¢/kWh. The largest cost savings are reported in the Texas (UCS) study, which estimates that the modeled Texas RPS could reduce consumer electricity costs by 5.2% (-0.4 ¢/kWh) compared to the business-as-usual reference case. The largest rate increase is predicted by the Arizona (PIRG) study, which estimates that electricity rates in the state could increase by 8.8% (0.7 ¢/kWh) compared to the reference case.

These outlying rate projections are a function of the assumptions used in each study. The Texas (UCS) study assumed that the large amount of wind development resulting from the Texas RPS would have ripple effects on the national level. Specifically, the model assumed that the significant amount of Texas wind capacity additions would stimulate wind technology cost reductions on the national level, which would lead to increased wind development and greater natural gas price savings nationwide. In the case of the Arizona (PIRG) study, the high rate impact projections are in large part due to the study's assumption that 20% of the required RPS generation would be produced by relatively high-cost solar technologies (for reference, the average contribution of solar technologies to RPS generation across all of the studies that modeled RPS resource mix is less than 4%).

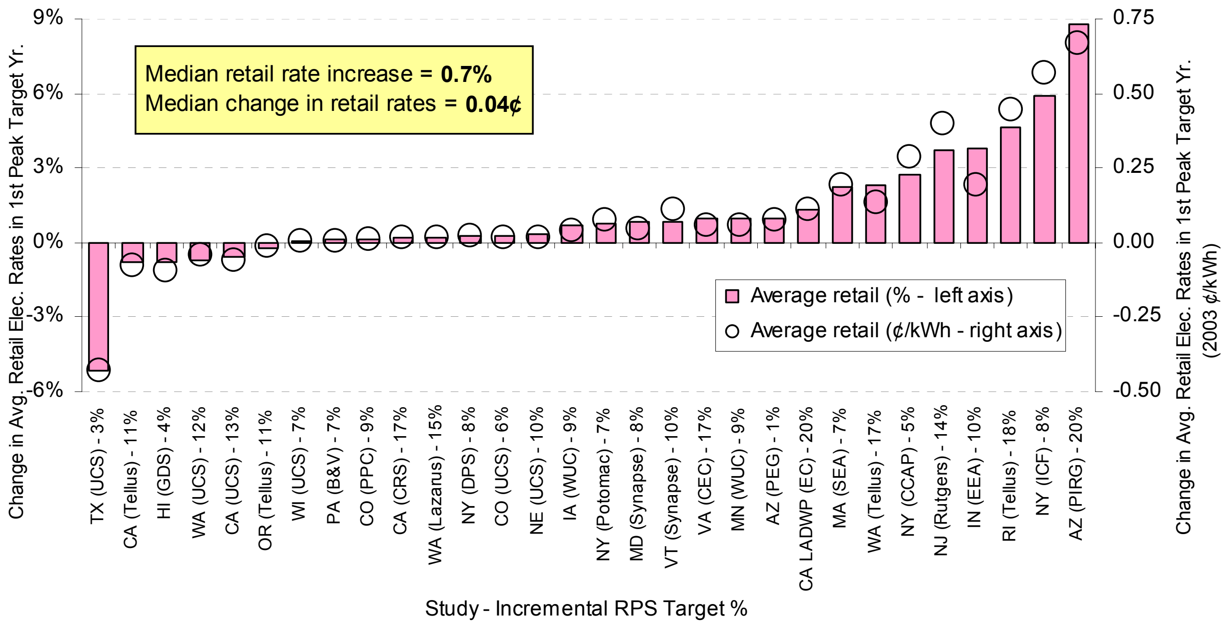

Figure 7. Projected RPS Electricity Rate Impacts by RPS Cost Study

Though most of the studies project relatively limited impacts on retail electricity rates, the wide range of impacts shown in Figure 6 and Figure 7 underscores the large variability among the studies' cost results. In fact, cost results can vary widely even within a single state. For instance, two of the three cost studies that analyze essentially the same RPS design in New York estimate retail rate increases of less than one percent (DPS and Potomac), but the third (the ICF study) projects the second highest cost increase of any study in our sample.[29]

Figure 8 presents a scatter plot of projected impacts on electric rates against the incremental RPS target as modeled by each cost study. There is a faint correlation between RPS target levels and incremental costs, but the R-squared of the linear regression is a modest 0.19. Clearly, factors beyond the RPS targets are driving expected costs.

The vertical error bars shown in Figure 8 represent the high- and low-cost estimates for each study that conducted scenario analysis around the base-case results. In some instances, these ranges can be extremely large. For example, the high estimate of the New Jersey Rutgers study, which applies to a scenario in which renewable technology fails to achieve expected future cost reductions, corresponds to a retail electricity rate increase of almost 23%. The results of this New Jersey study, as well as the other studies that conduct scenario analysis, reveal the sensitivity of projected RPS-induced costs to key input parameters. Section 4 contains a more detailed description of these scenario analyses.

[29] The fourth New York RPS study, which was written by CCAP, analyzes an RPS policy that is substantially different from the policy that was ultimately adopted.

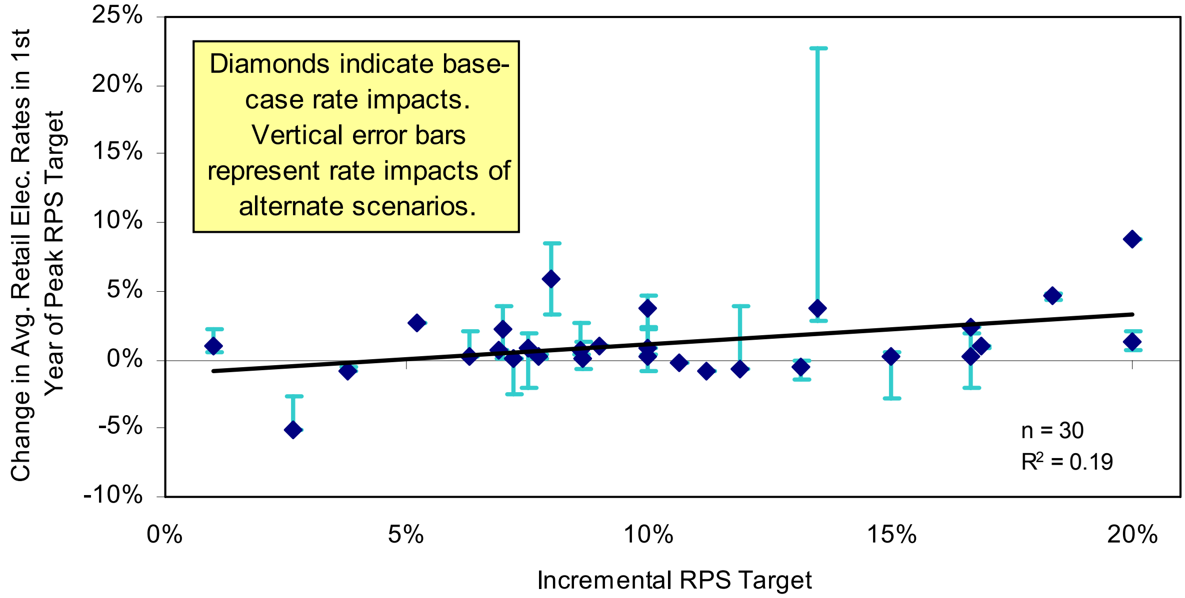

Figure 8. Relationship Between Incremental RPS Targets and Retail Electricity Rate Impacts

Direct costs can also be presented as the expected increase in an average residential consumer's monthly electricity bill. Figure 9 presents projected cost impacts in this form, along with error bars for those studies that include scenario analyses. As shown in these figures, cost studies of RPS policies in Eastern states (and, more specifically, in Northeastern states) generally forecast higher cost impacts than studies of RPS policies in other parts of the country. Four of the six highest projected RPS-induced cost impacts are from studies of Eastern states. The higher expected costs in the East are most-likely attributable to the region's lower renewable resource potential compared to elsewhere in the country and the higher costs of developing renewable projects in the Northeast. Though the predicted costs of RPS policies in the East may be relatively high compared to those in the rest of the country, the median monthly residential bill impact among the Northeastern studies is still modest, at \$0.82/month. Among the other (non-Eastern) states, the median monthly bill impact for an average household is \$0.13/month. All but three of these studies forecasts monthly bill increases of less than \$1.00 for an average household. The most noteworthy exception is the Arizona PIRG study, which projects a bill increase of over \$7.00 per month.

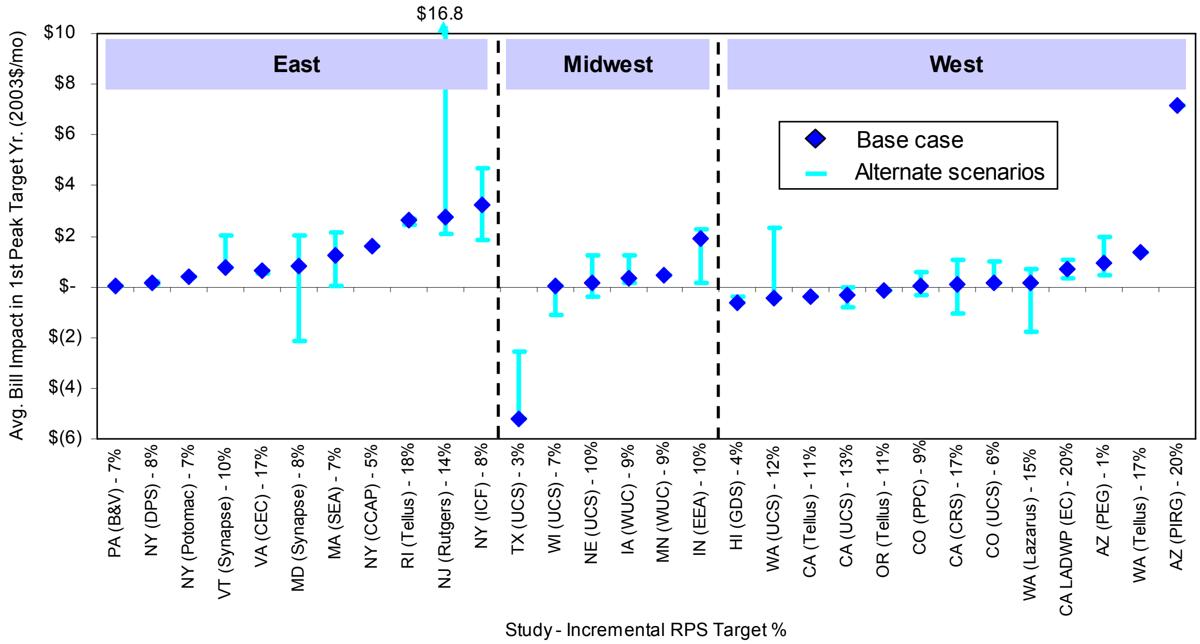

Figure 9. Typical Residential Electricity Bill Impacts Projected by RPS Cost Studies

4. Scenario Analysis

Twenty-one of the 28 studies we reviewed include some form of scenario analysis using input assumptions that differ from those used in the base case. No single type of scenario is dominant. This diversity is not surprising, and reflects differences among the RPS policies and the electricity market conditions in each state.[30]

Among the studies we reviewed, the scenarios that are most commonly modeled are the availability of the federal production tax credit, varying projections of renewable technology cost, fossil fuel price uncertainty, and wholesale market price uncertainty (Figure 10).[31] The prevalence of these scenarios perhaps implies – but does not prove – that projected RPS costs are more likely to be sensitive to these particular factors than to others. RPS cost sensitivity may be caused by a scenario's potentially large effect on electricity rates, by a high probability that a scenario will occur, or by a combination of a scenario's rate impact and probability of occurrence.

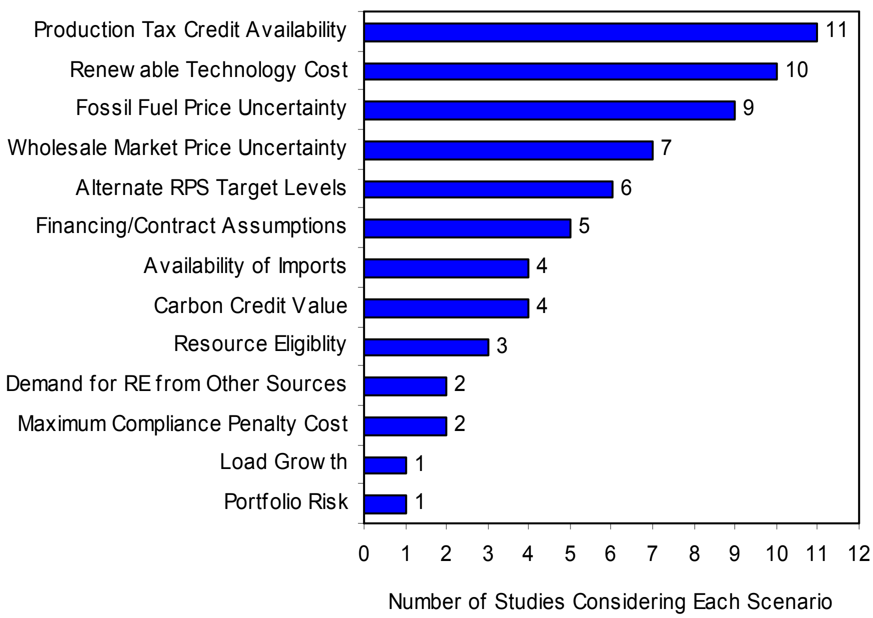

Figure 10. Sensitivity Scenarios Modeled by RPS Cost Studies

The sensitivity scenarios modeled by the RPS cost studies are briefly described below, in qualitative terms (as before, we use the term "base case" to represent the baseline RPS scenario, while we use the term "reference case" to refer to the business-as-usual, non-RPS scenario.):

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[30] As an example, cost studies of states that rely heavily on natural gas for their electricity supply are more likely to model the sensitivity of RPS rate impacts to changes in natural gas prices than are cost studies of states that are more reliant on coal.

[31] Two of the cost studies that we reviewed, New York (DPS) and Pennsylvania (B&V), include scenario analysis in earlier versions of their rate impact analysis, but did not re-model those scenarios in updated versions of that analysis. We do not include the results of these earlier analyses in this report, but we do count the scenario categories in Figure 10.

- **Production Tax Credit availability:** Reflects changes to the assumed duration of federal production tax credit (PTC) availability. Extended availability of the PTC results in lower RPS rate impacts.
- **Renewable technology cost:** Reflects changes to base-case renewable technology cost, fuel, and performance assumptions. Higher expected renewable technology costs result in higher RPS rate impacts.
- **Fossil fuel price uncertainty:** Reflects changes to reference-case fossil fuel (typically natural gas) prices. Higher fossil fuel prices result in lower expected RPS rate impacts.
- **Wholesale market price uncertainty:** Reflects changes to reference-case wholesale electricity market prices. Higher wholesale market prices result in lower RPS rate impacts.
- **Alternate RPS target levels:** Reflects variations in the RPS percentage target. Higher targets tend to increase expected RPS rate impacts, either positively or negatively depending on the sign of the rate increase in the base case.
- **Financing/contract assumptions:** Reflects changes to base-case renewable financing terms and/or different contractual arrangements for procuring renewable power. Lower cost financing and more favorable contract assumptions include lower finance rates and long-term, fixed-price contracts for bundled power.
- **Availability of imports:** Reflects variations in the treatment of renewable power or RECs that are imported from nearby states or regions. In addition to policy considerations, other factors, such as technical constraints (e.g. transmission capacity constraints) and economic constraints (e.g. wheeling charges) can also influence import availability. Increased import availability increases renewable supply and results in lower expected RPS rate impacts.
- **Carbon credit value:** Reflects the value of renewable energy in reducing carbon dioxide emissions, especially if future regulations limit such emissions. Applying this credit to renewable energy (or, conversely, applying an additional cost to fossil fuel-based generation) reduces the expected/effective cost of RPS compliance.
- **Resource eligibility:** Reflects different definitions of RPS-eligible renewable generating technologies. Looser, or less restrictive, eligibility provisions increase the supply of RPS-eligible resources and result in lower expected rate impacts.
- **Demand for renewable energy from other sources:** Reflects changes in demand for RPS-eligible renewable energy supply from other sources, such as voluntary green power programs or RPS policies in neighboring states. Increased demand for renewable energy – regardless of the source – results in higher expected RPS rate impacts.
- **Maximum compliance penalty cost:** Reflects the assumption that electricity suppliers pay the non-compliance penalty or alternative compliance payment that is assumed to apply to the RPS. Penalties and alternative compliance payments can sometimes bound the maximum possible cost of an RPS, because suppliers may choose to pay the penalty or alternative compliance payment when it presents a less costly alternative to purchasing renewable energy or RECs.
- **Load growth:** Reflects changes to load growth assumptions. Higher load growth increases renewable power obligations in MWh terms, which may result in higher RPS rate impacts.
- **Portfolio risk:** Reflects the cost risk associated with a given electricity generation portfolio. In theory, an RPS will reduce portfolio risk by reducing exposure to variable fuel costs, but this reduction in risk may result in higher average rate impacts. Depending on their resource constitution, RPS generation portfolios may have different levels of risk (with corresponding differences in rate impacts).

Due to the wide range of scenarios modeled and the different assumptions used within each type of scenario, it is difficult to draw definitive conclusions about the relative impact of different cost drivers. Figure 11 and Figure 12, however, show the expected cost impacts of all of the scenario types modeled in the RPS cost studies that we reviewed.[32] Within a data column, each marker represents the change in base-case monthly residential electricity bill impacts caused by an individual scenario from a single RPS cost study. Figure 11 presents data on scenario types that result in lower RPS-induced electricity rate/bill impacts, while Figure 12 presents data on scenario types that generally result in higher electricity rate/bill impacts.

Most individual scenarios do not appear to have major impacts on base-case RPS costs. With few exceptions, the residential electricity bill impacts of these scenarios – as measured by changes from the base case – are less than $1 per month. Though such changes are not overwhelming, it is important to recognize that the median *base-case* residential electricity bill impact among the studies in our sample is just $0.38/month, with a range of ($5.19)/month to $7.14/month. Therefore, even a $1/month change from this base-case is sizable in percentage terms, and demonstrates significant cost sensitivity to input parameters.

In some cases, scenarios result in incremental costs well above $1/month for an average household. The most conspicuous example is the New Jersey "high technology cost" scenario, which exceeds the base-case bill impact by about $14/month. This is largely explained by the relatively high amount of solar energy required by the New Jersey RPS, which would result in substantially higher costs if the technology does not become more economic over time.[33]

A confluence of multiple scenarios can also impact costs more dramatically. In the Massachusetts (SEA) study, for example, none of the individual cost-saving scenarios results in monthly electricity bill savings of more than $0.40/month relative to the base case.[34] However, the study also models the combined impacts of all of these cost-reducing scenarios and finds that they could save average residential customers $1.19 per month compared to the base case (the numbers are roughly reversed for the cost-increasing scenarios). This convergence of cost-reducing factors represents a "best case" scenario, though bill savings could be higher still if more aggressive assumptions are used.

It is also apparent from the data that rate impacts are far from symmetrical within each scenario, at least among our sample of studies. In three instances, for example, higher expected fossil fuel prices result in rate savings for an average household of over $1 per month relative to the base case, but the highest rate increase due to lower fossil fuel prices is just $0.79 per month. This asymmetry may result from uneven assumptions in the high and low scenarios (i.e. a high natural gas price forecast that departs from the base case forecast by more than the low forecast), or it

[32] Some studies model more than two scenarios for each scenario type, e.g. three different natural gas price forecasts instead of just a high and low forecast. In these instances, we include only the two scenarios (one cost-decreasing and one cost-increasing) that have the greatest impact on rates.

[33] In reality, higher-than-expected solar technology costs would probably cause legislators to change the RPS policy to require less solar energy rather than allow RPS rate impacts to reach such an extreme level.

[34] These individual cost-saving scenarios include: lower wholesale market price, less demand for renewable energy from other sources, PTC extension, more favorable financing, lower import costs, and lower renewable technology costs and fuel costs.

may result from significant non-linearity in the study's model. Natural gas price scenarios are further discussed in Section 5.2.

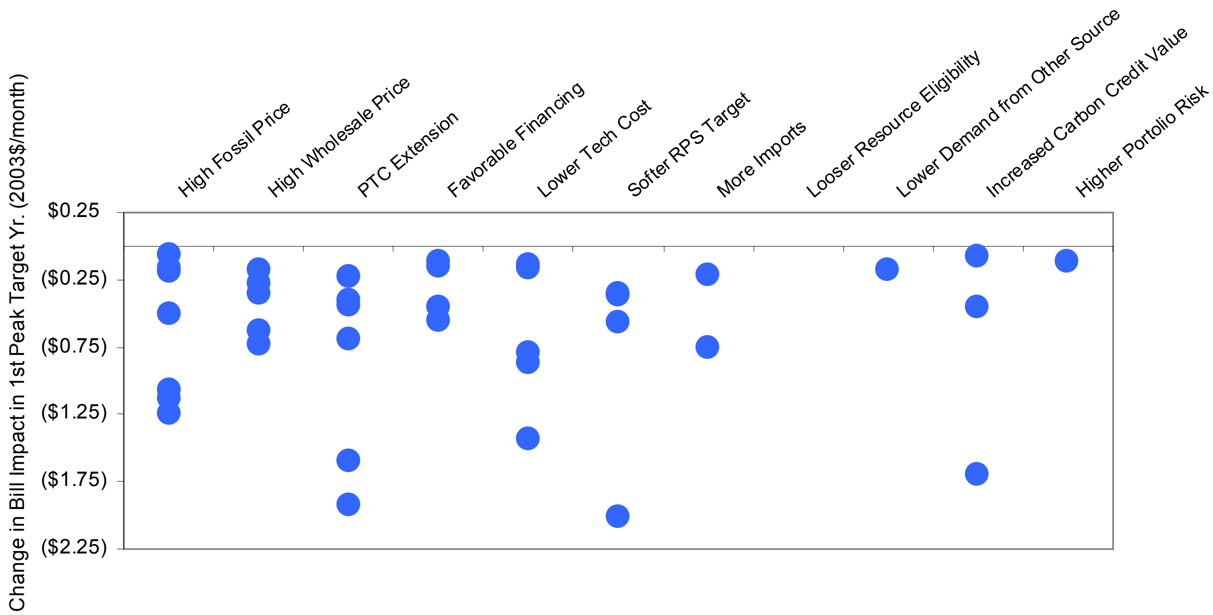

Figure 11. Changes to Base-Case Residential Monthly Electricity Bill Impacts by Individual Driver (Cost Decreasing Scenarios)

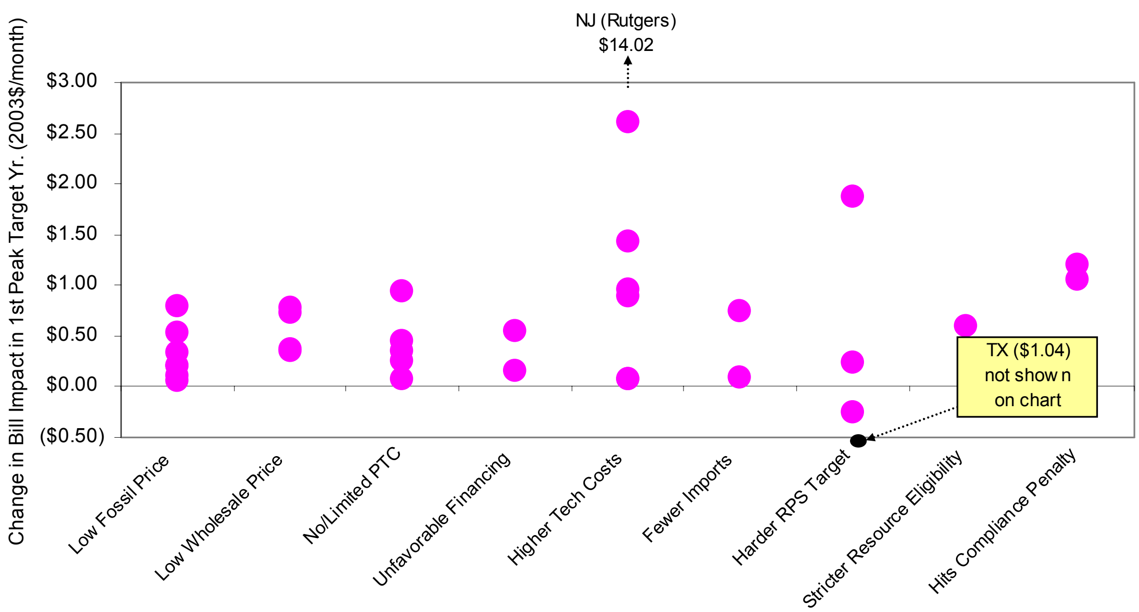

Figure 12. Changes to Base-Case Residential Monthly Electricity Bill Impacts by Individual Driver (Cost Increasing Scenarios)

5. Projected Benefits

Many of the studies also evaluate the potential public benefits of RPS adoption. These benefits can be divided into three main categories: macroeconomic, risk mitigation, and environmental. Figure 13 identifies the number of studies that model each of these potential benefits. Though the figure includes only the primary metrics of employment, gross state product, and income under the category of macroeconomic benefits, a smaller number of studies also quantify revenues from state income, sales, and property taxes, and land lease payments.[35]

Of the benefits covered in this section, only the risk mitigation benefits affect the *direct costs* shown in Section 3.3, and they do so only to the extent that they affect electricity prices. For example, the natural gas price suppression effect described later presumably reduces wholesale electric prices by decreasing the price of natural gas used in the electricity sector; these effects (where modeled) were included in the direct cost results presented earlier. In contrast, the benefits of lower natural gas prices for consumer natural gas bills (which can be much larger on a dollar-per-customer basis) are not included in the direct cost impacts reported earlier.

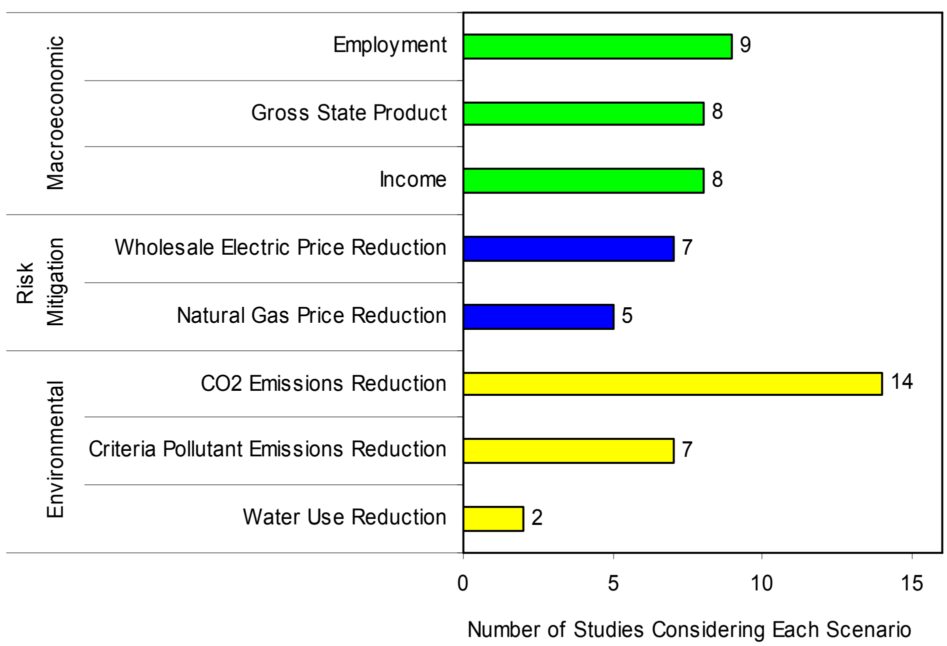

Figure 13. Potential Benefits Modeled by RPS Cost Studies

[35] Arizona (PIRG) and New Jersey (Rutgers) quantify at least one type of tax effect. Arizona (PEG) quantifies the combined impact of tax revenue and income, but does not provide a separate estimate of each individual effect. In addition to tax impacts, Colorado (UCS), Nebraska (UCS), Texas (UCS), Washington (UCS), and Wisconsin (UCS) also quantify land lease payments to rural landowners.

5.1 Macroeconomic Impacts

State RPS cost studies are increasingly considering macroeconomic impacts; seven of the nine studies in our review that estimate RPS employment benefits were published in 2004 or later. In addition, over the last several years, a number of RPS studies have exclusively modeled macroeconomic impacts; these studies are not included in our review, as we are primarily interested in expected rate impacts.[36] The recent emphasis on the potential macroeconomic benefits of state RPS policies may signify that RPS proponents are increasingly accentuating these impacts to justify policy action.

Figure 14 and Table 3 show the projected employment impacts from the nine cost studies in our sample that model these effects (Table 3 also shows gross state product effects).[37] All of the studies predict some level of net employment gain, ranging from a few hundred to several thousand jobs created. That growth in renewable energy generation may increase net employment is consistent with past analyses, which have often shown renewable energy to be more labor-intensive than conventional forms of electricity production (see, e.g., REPP 2001; Kammen et al. 2004).

Since the studies use different methods[38] and units[39], and estimate employment impacts of RPS policies of vastly different size, 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 renewable energy generation required to meet modeled RPS policies. This may be due to different mixes of renewable technologies developed, different assumptions concerning in-state versus out-of-state renewable energy project development and manufacturing, and different approaches to the incorporation (or lack thereof) of energy bill impacts into the macroeconomic analysis.[40]

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[36] These include: Bournakis et al. (2005), Perryman et al. (2005), and Altman et al. (2002).

[37] Though we label the employment impacts in Figure 14 and Table 3 as "Incremental Net Jobs in Peak Target Year," they may actually represent cumulative impacts in some cases, e.g. they may count increases in short-term construction jobs from earlier years that no longer exist in the peak target year. These and other timeframe and employment-type distinctions are not always clear in the studies, so we present the data with significant caveats.

[38] With the exception of Arizona (PEG), all of the studies in Figure 14 conduct input-output analysis that considers not only direct effects, but also indirect and induced employment gains and gross state product impacts. The specific tools used to conduct this analysis, however, vary by study. Arizona (PEG) is the only study that uses a "back-of-the-envelope" calculation to estimate direct economic effects

[39] Employment impacts, for instance, are typically reported using one of two metrics: "jobs," which are often of indeterminate length, and "job-years", which quantify both the number of jobs created and the duration of those jobs.

[40] Specifically, all of the studies summarized here except for Arizona (PEG) review the net employment gains of renewables deployment inclusive of job losses associated with the reduction in conventional forms of electricity production (Arizona (PEG) apparently does not account for these job losses). A majority of the studies – Arizona (PIRG), Colorado (UCS), New Jersey (Rutgers), Texas (UCS), Washington (UCS), and Wisconsin (UCS) – evaluate the influence of RPS-induced retail rate impacts (either positive or negative) on employment (e.g., if an RPS is expected to raise retail electricity rates, those increases would be expected to result in some loss in statewide employment). The Washington (UCS) results presented in this report, however, do not include these retail rate impacts because UCS was unable to provide impacts that are uniquely associated with renewable energy (their analysis also included energy efficiency impacts).

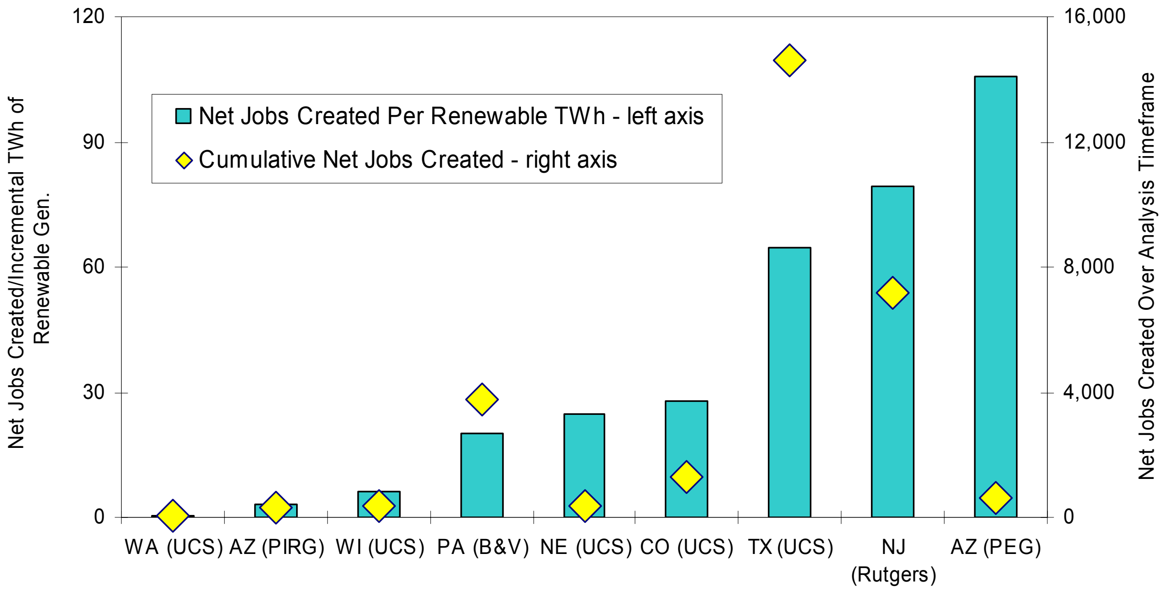

Figure 14. Employment Impacts Predicted by RPS Cost Studies

Table 3. Employment and Gross State Product Impacts Predicted by RPS Cost Studies

Cost Study	Incremental Net Jobs In Peak Target Year	Timeframe of Analysis	Cumulative Incremental RPS Target (GWh)	Change in Gross State Product ($2003 Millions)	Model Used
Arizona (PIRG)	308	2005-2020	96,500	$374 (in 2020)	IMPLAN
Wisconsin (UCS)	380	2006-2020	61,300	$95 (in 2020)	IMPLAN
Nebraska (UCS)	357	2003-2012	14,500	$37 (in 2012)	IMPLAN
Arizona (PEG)	600	1998-2010	5,700	n/a	Spreadsheet
Colorado (UCS)	1,290	2005-2020	46,500	$51 (in 2015)	IMPLAN
Pennsylvania (B&V)	3,747	2006-2025	186,600	$9,038	RIMS II
New Jersey (Rutgers)	2,600-11,700	2005-2020	90,300	$203-1014 (in 2020)	R/ECON I-O
Texas (UCS)	14,600	2005-2025	225,800	$61 (in 2025)	IMPLAN
Washington (UCS)	30	2010-2025	76,400	$10 (in 2020)	IMPLAN

Note: All employment figures represent employment gains that occur in the state of the modeled RPS. 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 other "Tier II" alternate (mostly non-renewable) energy sources. Employment and gross state product figures from Washington (UCS) represent only the impacts of the renewable energy additions of the RPS (the study also models an efficiency standard), and do not include induced impacts from energy price changes. The Pennsylvania and Arizona employment figures are calculated by dividing the job-years reported in the studies by the length of the study's timeframe. Lower and upper bounds of range of New Jersey (Rutgers) impacts represent results from two renewable technology manufacturing scenarios: one in which all renewable technology is manufactured out-of-state, and one in which 100% of renewable technology is manufactured in-state (the data in Figure 14 represents the average of these two scenarios). Wisconsin (UCS) provides Scenario 2 results in the report text, but data shown here is from Scenario 1 (to be consistent with our base-case designation).

5.2 Risk Mitigation Benefits

Two distinct types of risk mitigation benefits have been evaluated in the RPS cost studies in our sample: energy price suppression effects and hedging energy price uncertainty.

5.2.1 Suppression of Electricity and Natural Gas Prices

The effect of incremental renewable generation on reducing wholesale electricity and natural gas prices is a significant potential benefit of RPS policies. However, few studies have attempted to quantify these price suppression effects, and the magnitude of these effects is somewhat uncertain.

5.2.1.1 Electricity price effects

In some instances, the increased cost of renewable generation relative to conventional fossil generation may be mitigated by cost savings that derive from reductions in wholesale electricity prices. Adding a substantial amount of low-marginal-cost renewable generation to the electricity system reduces the demand for generation from conventional sources and may thereby suppress competitive wholesale energy prices. This effect may only be significant and important in markets with liquid wholesale spot markets, such as New England, New York, and PJM. Moreover, the magnitude of this effect is debatable: some studies believe that significant long-term reductions in wholesale energy prices are possible, while others have concluded that such reductions are likely to be minimal and fleeting as suppliers adjust to the new market conditions. According to the latter argument, to fairly evaluate this effect, it is critical to consider supplier response to lower prices (e.g., lower prices may slow capacity expansion, thereby increasing prices up to their pre-RPS levels, either through wholesale energy prices and/or through separate capacity markets).

The four RPS cost studies in our review that quantify these potential savings are all analyses of RPS proposals in New York (Figure 15).[41] Each of the studies projects overall long-term *firm* price reductions, ranging from 0.4% (NY CCAP and NY Potomac) to 2.6% (NY ICF).[42] These overall effects are influenced by impacts on both wholesale energy and capacity prices. Three of the four studies, for example, predict increases in capacity prices (capacity prices have been converted to $/MWh in the figure, for ease of comparison), suggesting that any reduction in wholesale energy prices due to an RPS may be partially or almost entirely offset by increases in

[41] Three other studies, Colorado (UCS), Rhode Island (Tellus), and Texas (UCS), also include some electricity price suppression effect (at a minimum through lower natural gas prices), but those effects are not specifically and separately quantified, and are therefore not reported here. In addition, New Jersey (Rutgers) includes a very small wholesale electricity price suppression effect that is induced by reductions in electricity demand that themselves are caused by higher overall electricity prices. Because this effect is fundamentally different from the price suppression effect that results from increased renewable generation, we do not include New Jersey (Rutgers) among the seven studies shown in Figure 13.

[42] The other study, New York (DPS), projects that firm wholesale prices will be reduced by 1.7%. For simplicity, we use price reduction data from Scenario 1 of New York (ICF). The price reduction effect is negligibly higher in Scenario 2.

capacity prices.[43] For instance, the Potomac study predicts that increases in long-run capacity prices will offset the majority of the wholesale energy price reductions. However, even small reductions in overall wholesale energy/capacity prices hold the prospect of offering significant aggregate savings to electricity consumers (which come at the expense of producers, so may not reflect a net societal gain).[44] Table 4 shows that projected residential electricity bills would range from $0.11/month to $0.57/month higher if the four New York cost studies had not modeled the effects of RPS generation on wholesale market prices.

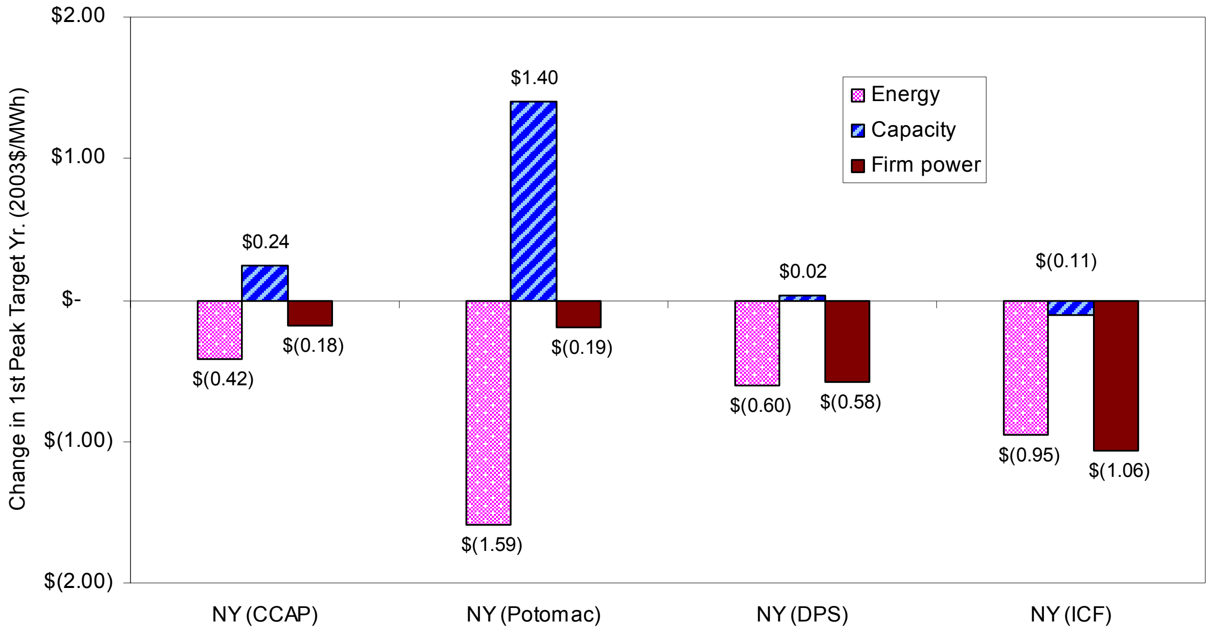

Figure 15. Wholesale Energy and Capacity Price Changes Projected by RPS Cost Studies

Table 4. Effect of Wholesale Market Price Reductions on RPS Rate Impacts in 1st Year of Peak RPS Target

Cost Study	Retail Rate Impact Accounting for Wholesale Price Effects (i.e. as Modeled)	Retail Rate Impact Excluding Wholesale Price Effects	Residential Electricity Bill Impact Accounting for Wholesale Price Effects ($/mo.)	Residential Electricity Bill Impact Excluding Wholesale Price Effects ($/mo.)
NY (CCAP)	2.7%	3.0%	$1.63	$1.76
NY (Potomac)	0.8%	1.0%	$0.42	$0.53
NY (DPS)	0.3%	1.0%	$0.14	$0.53
NY (ICF)	5.9%	7.0%	$3.25	$3.82

[43] This effect is likely to occur in markets where the capacity factor of renewable generators is significantly higher than the capacity credit that they receive, thus shifting revenues from the energy to the capacity market.
[44] As noted earlier, these electricity-sector consumer savings (where modeled) are embedded in the direct cost results presented in Section 3.3.

5.2.1.2 Natural gas price effects

State RPS policies will also reduce fossil fuel consumption by avoiding generation from conventional sources, primarily natural gas and coal. Many recent reports have shown that increased renewable energy and energy efficiency deployment may put downward pressure on natural gas prices by reducing national and regional gas demand and thereby easing supply constraints (see, e.g., Elliot and Shipley 2005; Wiser et al. 2005). Reduced gas prices will result not only in lower wholesale electricity prices (this effect, where modeled, is included in the direct cost results presented in Section 3), but also in lower end-use natural gas bills. Increasingly, renewable energy proponents cite this benefit in support of RPS policies, though it deserves note that these consumer savings come at least in part at the expense of natural gas producers.

Five of the studies in our sample quantify natural gas price effects in their base case analysis. Three of these five studies quantify the expected natural gas price savings in terms of in-state or intra-regional delivered natural gas prices, which (relative to the reference case scenario) are estimated to decline by an average of 0.1% in Rhode Island (Tellus), 0.6% in Texas (UCS), and 0.8% in Colorado (UCS) (Figure 16).[45] Of the other two studies, the New York ICF analysis concludes that the natural gas savings are negligible, despite electricity sector natural gas demand reductions of 4-5% in the last year of the study (2013). The remaining study, New York (CCAP), also does not specifically enumerate its natural gas price reductions, but concludes that natural gas prices will decline slightly in 2010 and increase slightly in 2020, in response to decreases in electricity sector natural gas consumption of 8% and 7%, respectively.

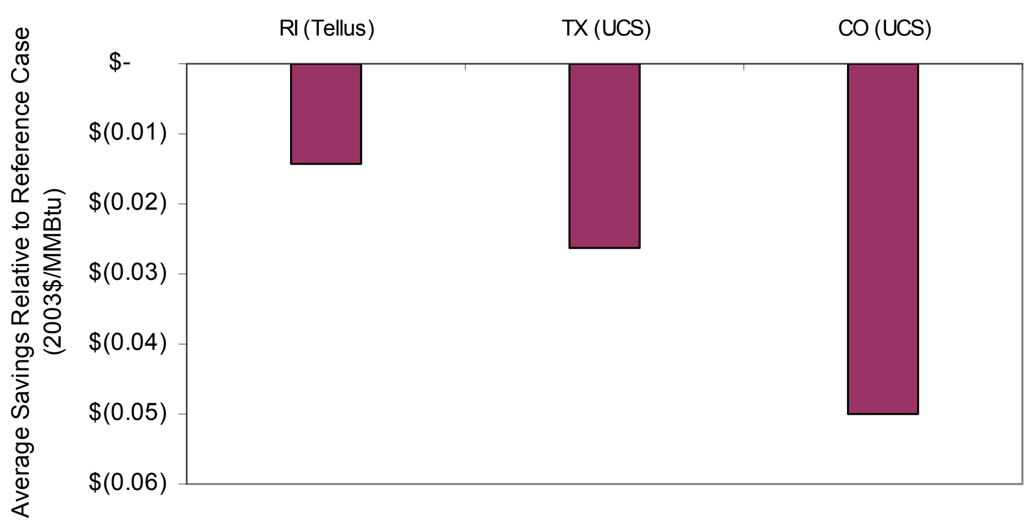

Figure 16. Delivered Natural Gas Price Savings Projected by RPS Cost Studies, Averaged Over Each Study's Timeframe

[45] These percentage reductions, and the data in Figure 16, represent the average change in delivered natural gas prices over the time period during which the RPS ramps up to its ultimate target level. This timeframe is 2005-2020 for Rhode Island (Tellus), 2005-2025 for Texas (UCS), and 2005-2015 for Colorado (UCS). Rhode Island and Colorado data are for non-electric customers only; Texas data includes savings for electric generators.

Three other studies – California (CRS), Maryland (Synapse), and Virginia (CEC) – externally estimate potential natural gas price savings for illustrative purposes only (i.e., these savings did not factor into the analysis of direct RPS costs). California (CRS) applies the empirical method developed by Wiser et al. (2005) to estimate potential price reductions. California (CRS) finds that gas prices would be reduced by an average of $0.02-0.06/MMBtu during the 2011-2020 timeframe. In lieu of estimating natural gas price reductions, Virginia (CEC) simply assumes that each MWh of renewable generation will result in three dollars of consumer savings, using the Wiser et al. (2005) results as a benchmark. Maryland (Synapse) models two scenarios in which natural gas prices are assumed to fall by 2% and 4% relative to the reference case forecast.

Natural gas price reductions caused by increased renewables deployment will benefit consumers nationwide, with a relatively small proportion of this benefit being gained by consumers in the state in which the RPS is adopted. Nonetheless, though the expected price savings in Figure 16 may appear insubstantial, consumer natural gas bill savings are sometimes projected to be large enough to eclipse the electricity bill impacts of some RPS policies.[46] This is true of the Colorado (UCS) study, which estimates that average residential natural gas bill savings in Colorado will reach $1.25 per month by 2015, compared to an estimated increase in electricity bills of just $0.13 per month in that year. By contrast, the Rhode Island (Tellus) and Texas (UCS) studies project much smaller natural gas savings. Rhode Island (Tellus) estimates average residential natural gas bill savings of $0.22 per month in 2020, compared to an expected increase in electricity bills of $2.64 per month in that year. Texas (UCS) estimates natural gas bill savings of $0.31 per month over the 2020-2025 timeframe, which is far smaller than the projected electricity bill savings of $4.26 per month over the same time period.[47] The authors of one of the New York (ICF) studies predict no change in natural gas prices despite a 4-5% reduction in New York's natural gas demand.

These contrasting results arise in part from very different assumptions concerning the price elasticity of natural gas supply nationally, and the impact of regional transportation constraints. The model used in the New York (ICF) study assumes that natural gas supply is inelastic at the demand reduction level induced by the New York RPS, while the model used in the Colorado (UCS) study assumes that reductions in natural gas demand in Colorado will have a relatively sizable impact on regional gas prices. More generally, one would expect that at least two conditions would be necessary to achieve significant *in-state* natural gas bill savings from a state RPS: (1) the state RPS would need to result in sizable reductions in natural gas demand, such that those reductions can influence *national* natural gas prices; and (2) the state would need to have significant aggregate natural gas demand, such that even modest price reductions could have significant overall bill impacts. Regional natural gas pipeline constraints may further increase projected regional savings in that reduced gas demand would alleviate both national supply and local transportation constraints.

[46] Because the data in Figure 16 are averaged over the "ramp-up" period of each RPS, the data likely under-represent the long-run natural gas savings that would result from RPS policies once they reach their ultimate renewable target level. We have presented average, rather than "initial peak year," savings because data from these studies occasionally show unpredictable effects in individual years where gas prices may fluctuate up or down from year to year without any discernible pattern. This is likely an artifact of the NEMS model, which these studies have used to quantify RPS impacts.
[47] We present average, rather than peak year, data for Texas because the natural gas savings data from the study exhibit substantial year-to-year variability as discussed generally in the previous footnote.

5.2.2 Hedging Energy Price Uncertainty

Though natural gas and wholesale electricity prices are uncertain and prone to significant fluctuation, the price of renewable energy is largely fixed. In the broader literature, a variety of methods have been developed to try to quantify the benefit of the price certainty that renewable energy can provide (see, e.g., Bolinger et al. 2006; Awerbuch 1993, 2003). With few exceptions, however, these methods have not been directly used in the RPS cost studies in our sample.[48]

Despite this, the value of renewable energy as a hedge against price uncertainty is implicitly considered by those studies that model natural gas and wholesale electricity price scenarios that differ from the base-case price scenario. The results of these analyses demonstrate that the value of renewable energy is especially great under scenarios of unexpectedly high natural gas and wholesale electricity prices.

Figure 17 illustrates the sensitivity of RPS costs to expected natural gas prices, for those studies that analyze multiple natural gas price scenarios.[49] With few exceptions, the expected cost of RPS policies appears to be moderately sensitive to changes in expected natural gas prices. A linear regression of this relationship has an R-squared value of 0.68 and a slope of -0.40. Taken at face value, this implies that a $1.00 per MMBtu increase in expected natural gas prices is projected to reduce the monthly incremental cost (or increase the monthly savings) of a typical RPS policy for an average household by $0.40 (relative to the base-case RPS scenario).[50]

Figure 18 shows the sensitivity of RPS costs to expectations of wholesale electric prices in the reference case. As with the natural gas results, changes in wholesale market prices have moderate effects on the expected bill impacts of RPS policies. A linear regression of this relationship yields an R-squared of 0.95 (though this is inflated by the high incidence of symmetrical data points across the y-axis) and a slope of -0.69. This suggests that a 1 ¢/kWh increase in (reference-case) expected wholesale electric prices will reduce the monthly incremental cost (or increase the monthly savings) of a typical RPS policy for an average household by $0.69 (relative to the base-case RPS scenario).

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[48] Based on the work conducted at Berkeley Lab (see Bolinger et al. 2006), the original Pennsylvania (B&V) study included a hedge adder of $0.50/MMBtu in its natural gas price forecast for one of its sensitivity scenarios; however, the updated version of the B&V analysis does not model this scenario. Virginia (CEC) uses a "mean-variance portfolio" analysis to highlight the risk reduction benefits of an RPS, but does not include hedge adders for fuel or wholesale electricity prices. The methodology of the Virginia study is described in greater detail in Section 6.1.

[49] In addition to those studies included in the figure, the Colorado (PPC) study estimates that residential customers would save $0.46 to $0.67 on their monthly electricity bills with an RPS in place during the two years in which hypothetical natural gas price spikes (the magnitude of which are not fully disclosed) occur.

[50] In reality, the relationship between RPS cost impacts and natural gas prices is probably not a linear one, due in part to fuel substitution effects, but we assume a linear trend for simplification.

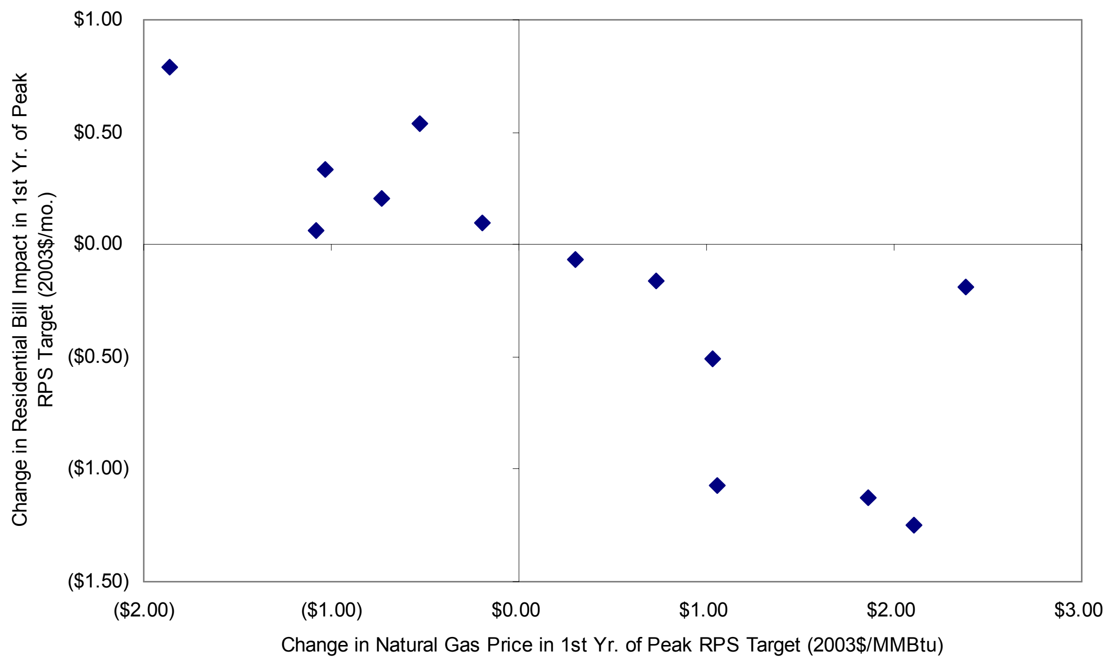

Figure 17. Sensitivity of RPS Bill Impacts to Alternative Natural Gas Price Scenarios

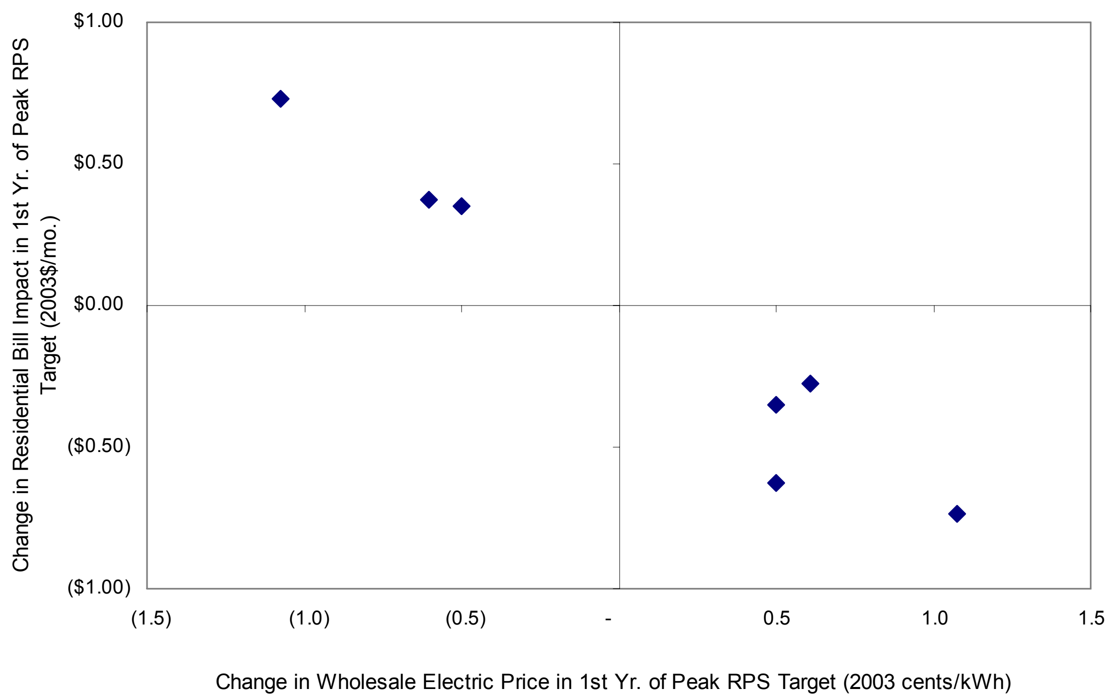

Figure 18. Sensitivity of RPS Bill Impacts to Alternative Wholesale Electric Price Scenarios

Data from these sensitivity scenarios show that RPS policies do offer some insurance in the event of higher-than-expected natural gas and wholesale electricity prices. The results suggest that a 20-25% change in wholesale electric price assumptions alters the expected cost of RPS policies by roughly 1% of overall retail rates, relative to the base-case scenario. This effect is roughly half as large in the case of natural gas prices: a 20-25% change in natural gas prices adds or subtracts roughly 0.5% of overall rates to the base-case RPS rate impact. These effects are far from negligible. More than two-thirds of the RPS cost studies report base-case retail cost increases of 1% or less, as reported earlier. Our findings show that increases in wholesale electric price expectations of 20-25%, or natural gas price expectations of 40-50%, could entirely offset a base-case RPS-induced rate impact of 1%.[51]

These results are especially notable in light of the relatively low natural gas price forecasts that were used by many of the studies in our sample. The average base-case delivered natural gas price forecast in the initial peak target year of each study (2010 to 2023, depending on the study) shown in Figure 17 is just $4.52/MMBtu. This compares to 2010 NYMEX Henry Hub futures prices that in 2005-2006 have regularly exceeded $6.00/MMBtu when converted to delivered prices in 2003 dollars.[52] If one used today's expectations for future natural gas prices (whether EIA forecasts or extrapolated NYMEX forward curves), the projected cost of state RPS policies would be significantly below (or savings significant above) the base-case cost study projections summarized in this paper.[53] We devote further discussion to the importance of natural gas price assumptions in Section 8.3.

5.3 Environmental Benefits

Of the potential environmental benefits quantified in the cost studies, carbon dioxide emissions reductions are the most common, appearing in half of the reviewed studies. Less than a third of the studies quantify reductions in criteria pollutants such as nitrogen oxides, sulfur dioxide, and mercury,[54] and only two studies quantify reductions in water use resulting from less cooling water consumption at fossil fuel plants.

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[51] Of course, these calculations assume that renewable energy offsets natural gas-fired electricity production. As gas prices have risen, the prospect for coal displacement has increased. In this instance, the "hedge" benefits of renewable energy – at least relative to natural gas prices – would be diminished.

[52] The EIA projects lower long-term delivered natural gas prices ranging from $4.97 to $5.27/MMBtu from 2015 to 2020 (EIA 2006a). Bolinger and Wiser (2005), however, observe that EIA natural gas price forecasts have been consistently below contemporaneous long-term forward prices in recent years, and argue that the cost of fixed-price renewable generation should be compared against long-term forward natural gas prices (that can be locked in with certainty) rather than uncertain EIA gas-price forecasts.

[53] Again, assuming that renewable energy continues to offset natural gas, rather than coal, generation.

[54] One reason that some studies may fail to estimate criteria air pollution reductions is that in many instances increased use of renewable energy will have little aggregate impact on those emissions. In particular, for pollutants covered by national or regional cap-and-trade programs, increased use of renewable energy may put downward pressure on the cost of compliance with the environmental regulations, but is unlikely to reduce aggregate emissions per se (except in the unlikely event that emissions allowances are explicitly retired). It appears that Indiana (EEA), New York (ICF) and New York (CCAP) are the only studies in our review that explicitly model the impact of RPS policies on emission allowance prices (the NEMS model, which is used by a number of additional studies to estimate RPS impacts, also typically addresses impacts on emission allowance prices, in which case CA/OR/WA (Tellus), Colorado (UCS), Rhode Island (Tellus), Texas (UCS) also incorporate these effects).. Future RPS cost studies may wish to evaluate these compliance cost effects, but without additional documentation and reasoning, should generally not claim RPS-induced emissions reductions from pollutants covered under cap-and-trade programs.

None of the studies directly quantifies the value of the health and economic impacts of reductions in air pollutant emissions and water use. Lack of agreement on a credible methodology for estimating these impacts, in dollar terms, makes quantification challenging. The New Jersey (Rutgers) study provides illustrative calculations of potential environmental and public health benefits using generic externality adders, but the calculations are not included in the study's cost results. A few other studies include qualitative discussions of these impacts.

Focusing on those studies that evaluate possible carbon reductions, Figure 19 presents the CO_2 reductions and implied CO_2 emissions rates of generation displaced by RPS resources in each study's peak RPS target year.[55] The magnitude of CO_2 emissions reductions, which is a function of the amount of incremental renewable generation and the emissions profile of displaced generation, varies tremendously across the studies, from a low of 0.88 million metric tons (MMT) in Rhode Island (Tellus) to a high of 26.0 MMT in California (Tellus). The displaced emissions rate also varies considerably, from a low of 0.22 metric tons of CO_2 ($MTCO_2$) per MWh in the Washington (Tellus) study to a high of 0.73 $MTCO_2$/MWh in the Colorado (UCS) analysis. The median displaced CO_2 emissions rate of 0.46 $MTCO_2$/MWh is low compared to the national electricity-sector average emissions rate of 0.60 $MTCO_2$/MWh (EIA 2006b), reflecting an expectation that RPS resources will largely displace generation from natural gas plants. The median displaced CO_2 emissions rate is 25% higher than the emissions rate of a new combined-cycle natural gas generator.

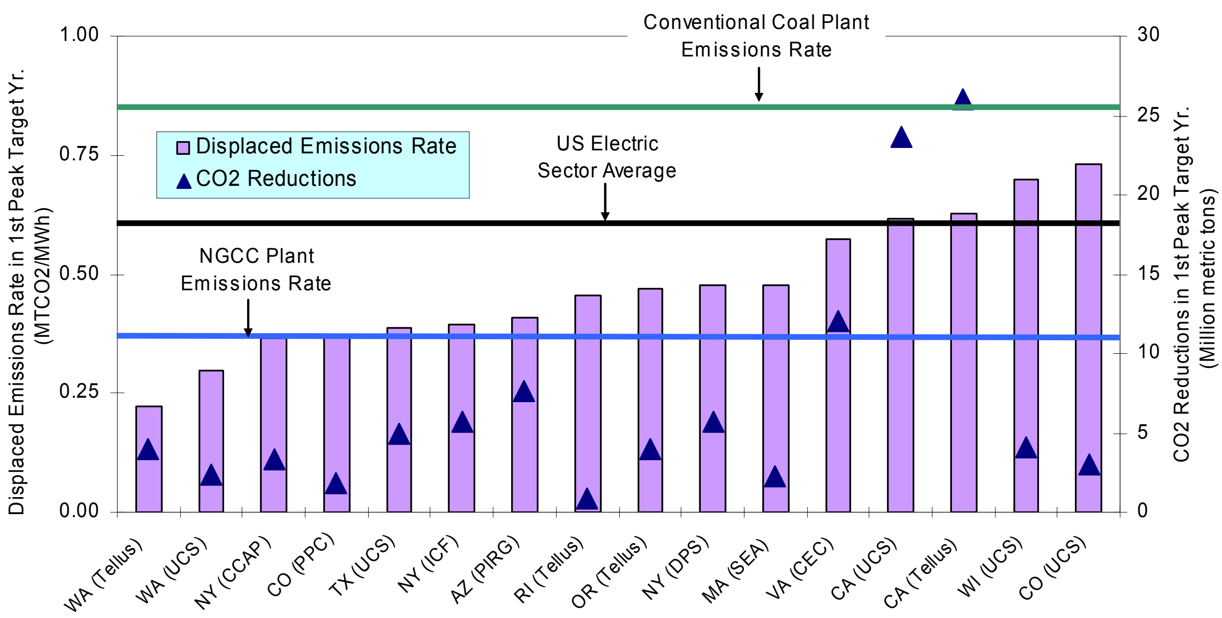

Figure 19. Projected CO_2 Emissions Displaced by RPS Policies in Initial Peak Year of RPS

The low displaced CO_2 emissions rates predicted by some studies appear puzzling at first. One study projects avoided CO_2 emissions rates that are lower than the emissions rate of a new

[55] Not all of the studies that quantify CO_2 reductions provide sufficient data to be included in the figure. Colorado (PPC) provides emissions reduction estimates for two scenarios: RPS generation displaces natural gas combined-cycle generation, and RPS generation displaces coal-fired generation. Since the study uses the estimated cost of a natural gas combined-cycle plant to calculate avoided costs, we use the CO_2 reductions from the former scenario.

combined-cycle natural gas plant. A few other studies seem to predict avoided CO_2 emissions rates that are roughly equal to or barely higher than that of a new combined-cycle natural gas plant, perhaps suggesting that RPS generation in these states will not displace any other conventional generators. This unexpected result can be partly explained by the fact that some studies predict that RPS generation will displace, to some degree, in-state hydropower generation. But the cost studies' treatment of renewable energy imports is perhaps the more significant factor. Specifically, a few of the studies with low rates of CO_2 displacement may not account for the CO_2 emissions of displaced fossil-fuel generation imports (focusing instead on just the displacement of in-state sources of CO_2).[56] If the RPS policy is expected to displace large amounts of imported fossil power, in-state CO_2 reductions can be significantly lower than the total reductions induced by the RPS. As a result, in-state CO_2 reductions may not appear commensurate with the total amount of incremental renewable generation.

Though reductions in carbon emissions is not the sole – or even primary – justification used to support many state RPS policies, Figure 20 shows the implied CO_2 abatement costs projected by those studies that estimate CO_2 reductions, focusing again on the peak RPS target year of each study.[57] CO_2 abatement costs vary widely, from a low of -\$427/MTCO$_2$ in Texas (UCS) to a high of \$181/MTCO2 ton in New York (ICF), with a median value of \$3/MTCO$_2$. The wide variation in CO_2 abatement costs is a reflection of the variation in retail rate impact projections among the studies. Not surprisingly, the four studies with the highest per-ton abatement cost projections in Figure 20 represent four of the six studies in our review with the highest expected base-case retail rate impacts. Another factor may be the analytic assumptions used to draw system boundaries. In some studies, a significant amount of the conventional generation expected to be displaced is projected to come from out-of-state generators, and if the corresponding emissions reductions are not counted, the per-ton abatement costs will be unduly inflated.

These implied CO_2 abatement costs can be benchmarked against the assumed CO_2 regulatory compliance costs that are incorporated in the long-term resource plans of electric utilities. According to Bolinger and Wiser (2005), for example, the recent resource plans of seven Western utilities assume CO_2 compliance costs (often as scenarios, not necessarily in the base-case analysis) ranging from \$0-\$64/MTCO$_2$ (levelized over each utility's planning horizon, in 2003 dollars). As reported in the same paper, this range is not inconsistent with the expected compliance costs shown in the broader modeling literature under a range of carbon reduction scenarios, including those estimated by the EIA under various regulatory regimes. The spread of abatement costs in Figure 20 is obviously far broader, but 13 of the 16 RPS cost studies included in the figure (if we count the California/Oregon/Washington Tellus study as three separate studies) project CO_2 reduction costs in the peak target year that fall within the \$64/MTCO$_2$ upper

[56] In cases where an RPS cost study reports CO_2 emissions reductions both in-state and regionally, we use regional data to present CO_2 reductions and to calculate CO_2 emissions displacement rates and implied abatement costs.
[57] These costs were calculated by dividing by the base-case direct RPS electricity cost impacts (which do not include natural gas bill reductions) in the initial peak target year of each study by the corresponding CO_2 reductions in Figure 19. Since these are single-year costs, they do not represent the average costs of CO_2 abatement over the lifetime of each modeled RPS policy. Furthermore, these costs are consumer costs, which often include wealth transfers to generators and do not necessarily reflect the true social cost of each RPS policy.

bound of the Western utility compliance cost assumptions. Seven of these studies project reductions in CO_2 emissions that come with net *savings* to electricity consumers.

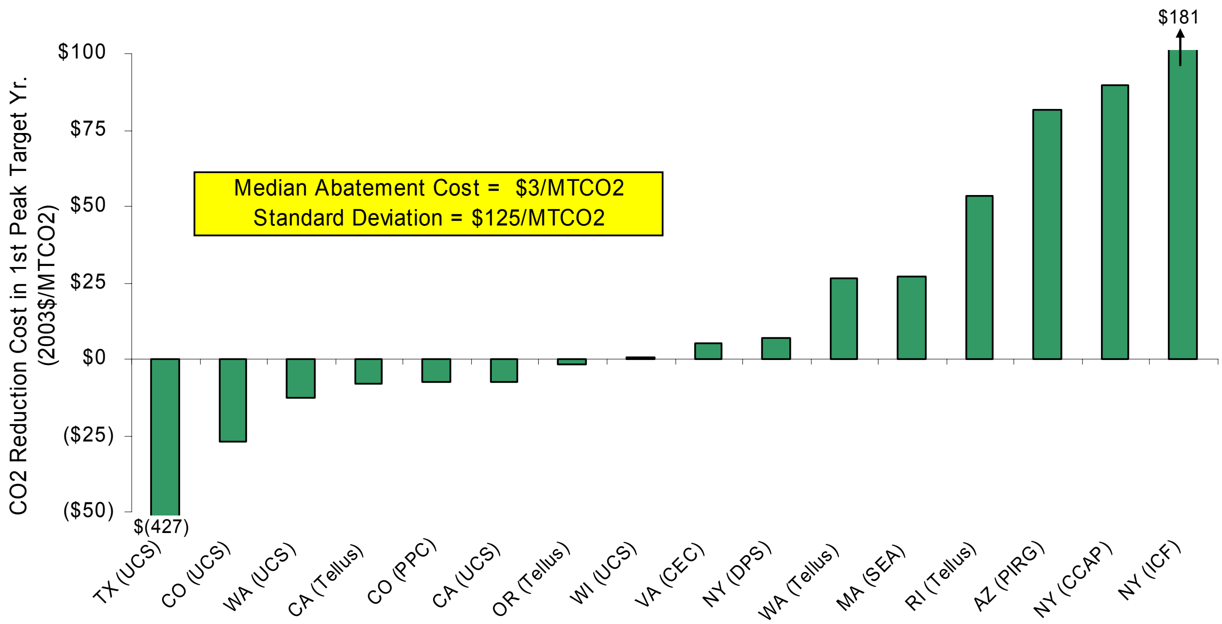

Figure 20. Projected CO_2 Abatement Costs in Initial Peak Year of RPS

More generally, the laws and regulations governing the environmental impacts of electricity generators are likely to change over the lifetime of electricity supply investments, as will the cost of compliance with existing environmental regulations. These changes could impose substantial costs on electricity-sector shareholders and customers (Repetto and Henderson 2003). Traditional air pollutants (SO_2, NOx, mercury, fine particulates, etc.) may be regulated more tightly in the future. Perhaps more significantly, new state or federal carbon regulations are possible over the 10+ year time horizons of state RPS policies. Because renewable energy sources are unlikely to be affected by these future requirements, purchasing or owning renewable energy assets may reduce exposure to these environmental compliance risks. This potential financial value has only been specifically quantified by four of the reviewed studies: Indiana (EEA) applies a carbon tax of $19/MTCO2 to fossil fuel-based generation in a scenario analysis; Iowa (WUC) considers a carbon credit value of $1-$46/MTCO$_2$ in various scenario analyses; Washington (UCS) assumes an emission allowance cost of $5/MTCO2 in 2013, gradually increasing to $28/MTCO2 by 2025; and Wisconsin (UCS) assumes an emission allowance cost that starts at $9/MTCO$_2$ and increases 5% per year thereafter. Given recent state activity on carbon emissions regulations, the carbon credit value of RPS policies may be worth further exploration in future analyses.

6. Comparison of Study Methodologies and Assumptions

Previous sections of this report have summarized some of the key findings of the RPS cost studies. We now turn to a description of the general modeling approaches used by these studies, and then to the major assumptions and sources that have been employed. In this section, we describe the four basic modeling approaches used by the RPS cost studies in our review and how assumptions about RPS market structure can significantly affect cost results. The remainder of the report provides more detailed descriptions of the methodologies and assumptions used to estimate renewable (Section 7) and avoided generation costs (Section 8).

6.1 General Modeling Approaches

The studies use a range of different cost estimation methods that do not always lend themselves to clear categorization. For descriptive purposes, we identify four broad categories of RPS cost estimation models, listed below in approximate order of increasing complexity (as we note later, more complexity does not necessarily equate with model superiority).[58] These approaches differ in the methods used to characterize the cost of renewable energy and the avoided cost of conventional fuels that are displaced by renewables deployment. Table 5 summarizes some the key aspects of the four modeling approaches described below, while Figure 21 identifies the studies that use each approach.

- **Category A: Spreadsheet model of renewable generation and avoided utility cost**

  Under this approach, both renewable generation and avoided utility costs are estimated with a spreadsheet model; the projected cost impact of an RPS is simply the difference in renewable generation and avoided utility costs. Sixteen of the 26 studies utilize cost estimation models that can be described by this broad category. The level of model complexity and sophistication varies widely – models range from simple estimates with few inputs to detailed supply curve models built from original research on the cost and availability of different generation options. The RPS-driven renewable resource mix can either be an input (in simpler approaches) or an output (in more detailed supply curve based approaches) of the model.

  The general advantage of a spreadsheet model comes in its transparency, simplicity, and relatively low cost. The input parameters in a spreadsheet model can typically be easily changed to accommodate scenario analysis and alternate assumptions. However, a spreadsheet model is typically unable to capture wholesale electricity and fossil fuel price feedbacks, and may not be well suited for modeling RPS policies in situations where these effects are expected to be sizable. A spreadsheet model also does not provide the same level of detail about avoided costs as a generation dispatch model. The additional detail offered by dispatch models can enable more accurate comparisons of the wholesale energy and capacity value of renewable generation relative to the value of conventional generation.

[58] Some of these characterizations are based on previous work by Grace et al. (2003).

- **Category B: Spreadsheet model of renewable generation and generation dispatch model of avoided utility cost using reference-case (non-RPS) resource mix**

  This approach uses the same general method for estimating renewable generation cost as the approach described in Category A, but estimates avoided utility cost through the use of a generation dispatch model (e.g. GE MAPS, PROSYM). These models are complex software programs that simulate the interaction of supply and demand in an electric system and provide detailed wholesale electricity price projections as a model output. Four of the studies in our sample employ this approach.

  The advantage of using a dispatch simulation model for this purpose is that it yields a potentially more accurate forecast of avoided utility costs than would a spreadsheet-based approach, and is capable of capturing the time-varying price of wholesale electricity. The latter is useful in estimating the true wholesale market value of renewable generation sources whose output profiles are temporally dependent.[59] Like Category A, however, this approach does not capture electricity and fossil fuel price feedbacks, because the dispatch model is only run based on the reference-case (pre-RPS) resource mix. This approach may also add additional costs because generation dispatch models often require specific training and can entail significant software or licensing costs.

- **Category C: Spreadsheet model of renewable generation and generation dispatch model of avoided utility cost using implied RPS resource mix**

  This approach again relies on a spreadsheet model to estimate the cost and availability of renewable generation. The dispatch model, however, is now run under two different resource supply scenarios: (1) the reference case, non-RPS resource mix (as in Category B); and (2) the implied RPS resource mix. The implied RPS resource mix is an output of the spreadsheet model, and the capacity of each renewable generator type is input into the generation dispatch model along with conventional generators. Though the renewable generators are included in the dispatch model run of the RPS case, the cost of these generators is modeled separately in the spreadsheet model.[60] The dispatch model thereby provides electricity production costs for the reference and RPS scenarios, and the model of the implied RPS resource mix will have a lower cost result because the renewable generators are modeled at zero-cost. The avoided cost of the RPS policy is then calculated as the difference between the total costs of these two scenarios, and can then be compared to renewable generation costs (which are an output of the spreadsheet model) to determine overall projected cost impacts. The two studies in our sample that employ this approach both evaluate the New York RPS using GE-MAPS software.

  Unlike the approaches used by Category A and Category B models, this approach has the advantage of quantifying the effect of RPS-eligible generation on reducing wholesale electricity prices. It can also provide specific information about which conventional

[59] Though, as we note in Section 8.1, spreadsheet models can also approximate the time-varying value of renewable generation.
[60] In these dispatch models, renewable generators are often modeled as “must-run” resources and are not subject to least-cost dispatch.

generators are likely to be displaced by increasing levels of renewable generation, which may provide a more accurate forecast of avoided pollution emissions than would other techniques. This approach does not, however, model the natural gas demand and price reductions that might result from RPS policies. Further, some generation dispatch models are not well suited to model renewable generation, and modeling the implied RPS resource mix within a dispatch model may require an immense number of input assumptions (e.g., location and temporal generation profile of each RPS resource).

- **Category D: Integrated energy model**

  An integrated energy model is an energy-sector model that endogenously determines fuel prices, capacity expansion, and electricity prices. The two most commonly used integrated energy models used for state RPS cost studies thus gar are NEMS (National Energy Modeling System), developed by the U.S. Energy Information Administration (EIA), and IPM (Integrated Planning Model), developed by ICF Consulting. With this approach, the mix of RPS resources and the production costs of those resources (as well as the cost of the resources that they offset) are estimated using the integrated energy model. Six of the studies in our sample employ this method.

  Perhaps the most advantageous feature of these models in the context of RPS cost analysis (relative to Category C models) is their ability to capture fossil fuel price feedbacks. Integrated energy models are also capable of endogenously estimating renewable technology costs (based, of course, on model input assumptions), though, as we explain in Section 7.3.2, their methods of doing so are sometimes controversial. Because these models often come with built-in assumptions already in place, it may not be critical to conduct a bottoms-up analysis to develop refined assumptions. Unfortunately, these models tend to be less transparent than others, and without detailed knowledge of the model's functionality, it can be difficult to understand how input assumptions lead to model results, particularly when the model and its source code are proprietary. Furthermore, an integrated energy model such as NEMS is designed to analyze the national energy sector and may require substantial modification to obtain the specificity and detail that is necessary to accurately model state-level policies.

Though we use these four categories to loosely summarize the modeling approaches employed by the RPS cost studies in our sample, not every study in our review fits neatly into one of the four categories. One study in particular deserves mention for the uniqueness of its modeling approach. Virginia (CEC) uses "mean-variance portfolio analysis" to show the cost impacts of electricity generation profiles at varying levels of financial risk.[61] The study's model is an Excel workbook that finds the minimum-cost electricity portfolio at a given level of risk, subject to other constraints. The model's use of a risk constraint distinguishes it from other studies that use Category A modeling approaches.

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[61] The model defines portfolio risk as a weighted average of the individual technology cost variances, adjusted for their co-variances.

Table 5. Summary of Basic Modeling Approaches

Model type	Category A	Category B	Category C	Category D
Description	Spreadsheet model of renewable generation and avoided utility cost	Spreadsheet model of renewable generation and generation dispatch model of utility avoided cost using reference-case resource mix	Spreadsheet model of renewable generation and generation dispatch model of utility avoided cost using implied RPS resource mix	Integrated energy model
Model platform	Spreadsheet	Spreadsheet + dispatch model (e.g. PROSYM, GE-MAPS)	Spreadsheet + dispatch model (e.g. PROSYM, GE-MAPS)	Macro energy-sector model (e.g. NEMS, IPM)
Ability to capture possible power market price suppression effect?	No	No	Yes	Yes
Ability to directly capture possible natural gas price suppression effect?	No	No	No	Yes
Ability to capture time value of renewable energy	Limited	Yes	Yes	Yes, but details depend on model
General transparency	High	Medium	Medium	Low
Number of required input assumptions	Few to many	Few to many	Typically many	Typically many, but may already be build into model
Advantages	Simplicity; transparency; flexibility; relatively low cost	May provide more accurate forecast of utility avoided cost and more detailed information about time-value of renewable generation	In addition to benefits of Category B, can capture market price suppression effect and provides detail on individual generators and avoided emissions	In addition to benefits of Category B/C, can capture effects on fossil fuel prices; can provide regional-level impacts; comes with built-in assumptions
Disadvantages	Inability to capture price feedbacks; avoided cost and renewable cost estimates can be crude	Additional expense and training required; inability to capture price feedbacks	May require large number of input assumptions; dispatch models may not be well suited to modeling renewable generators; does not model reductions in fuel price	Lack of model transparency; model may require modification for state-level analysis; can be difficult and costly to use

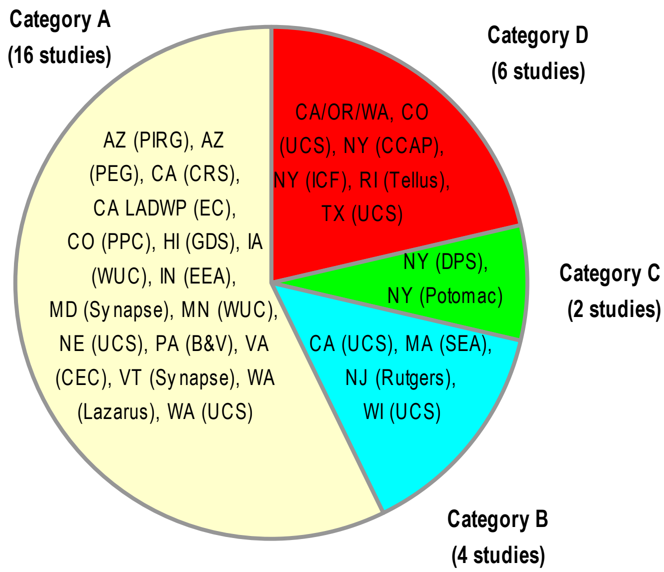

Figure 21. General Modeling Approaches Used for Estimating RPS Costs

Overall, this diversity of modeling approaches indicates that a standard template for state RPS cost estimation has yet to emerge. One might assume that accuracy increases with each modeling approach from Category A to Category D, as each successive model tends to provide more detail and captures more complexity. However, not enough is yet empirically known about the actual cost impacts of RPS policies to validate the accuracy of one model over another. Energy markets are subject to significant uncertainty, and future renewable energy costs, while less volatile than conventional electricity prices, are also uncertain. As a result, the assumptions governing these costs may ultimately prove more important than the choice or complexity of the model itself. In fact, as described above, each modeling approach possesses advantages and disadvantages, and no single approach is clearly superior to the rest. Instead, the choice of the modeling approach should be linked to the time and resources available to the study team, the goals of the study, the need for transparency and multi-stakeholder involvement, and the availability and quality of input data, among other factors

6.2 RPS Market Structure

The presumed structure of the RPS market in a given state or region is an important consideration for modeling the cost impacts of an RPS policy. In the paragraphs that follow, we describe possible RPS market structures and the modeling approaches that cost studies have used to represent these structures.

Much as electricity suppliers can purchase power to meet their load through a variety of different contract types, suppliers in some markets may be able to meet their RPS obligations through multiple contract and compliance strategies. Renewable energy certificates, or RECs, are used in many RPS markets to demonstrate compliance with renewable mandates. RECs can often be sold or traded separately from the electricity commodity itself, and thereby create a supplemental revenue stream for renewable generators. RECs can be bought under long-term contract, or in short-term markets. The use of short-term REC transactions is most common in restructured electricity markets, where retail suppliers are less likely to pursue long-term contracts with renewable generators. Brokered REC markets have also emerged in these regions.

In situations where RECs are primarily obtained in spot or short-term forward markets rather than under long-term contracts, there is little incentive for renewable generators to sell below the current spot price of RECs. In this **market-clearing** model, the incremental cost of the highest-cost marginal renewable generator at any given time effectively determines the REC price, which is then paid to all renewable generators regardless of their actual costs (see Figure 22). This allows lower-cost generators to earn revenues that exceed their costs – not unlike any other commodity market – and can lead to higher RPS compliance costs for ratepayers.[62] At a minimum, this market-clearing model is appropriate for estimating the retail rate impacts of RPS policies in competitive electricity markets that are expected to primarily feature short-term REC contracts. The market-clearing model is exemplified by the RPS policies in much of the Northeastern U.S., where retail electricity suppliers commonly purchase RECs in short-term markets to meet their RPS obligations.[63] However, medium- and long-term contracts for RECs have been executed in all of these markets, though in many cases annual or spot purchases for RECs are still the most common form of RPS compliance.

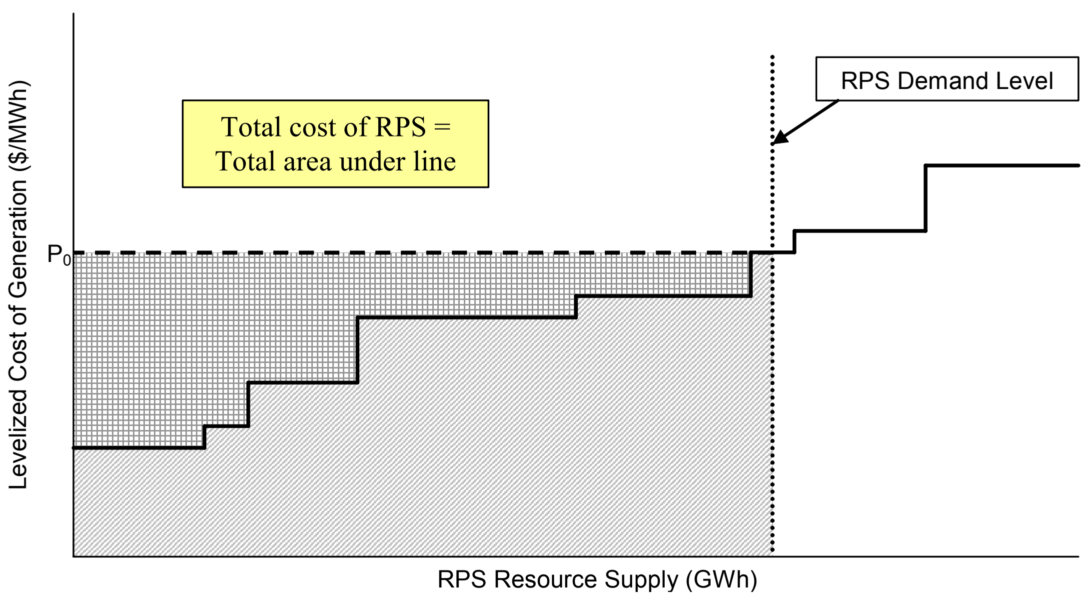

Figure 22. Graphical Representation of Market-Clearing RPS Compliance Model

[62] Note that the *social cost* of the policy still represents the area under the stair-stepped renewables supply curve. The area below the dashed horizontal line and above the step function represents producer surplus: profit received by generators that comes at the expense of consumers, and that is properly considered a wealth transfer, not a true social cost.
[63] A shortage of qualifying renewable supply in the early years of the Massachusetts RPS has driven REC prices to roughly $50/MWh. RPS officials in New England and elsewhere are understandably interested in avoiding future REC supply shortages that lead to such high costs, and some states now provide technical and financial support to facilitate long-term renewables contracts.

Even in markets dominated by longer-term contracts (with or without RECs), the pricing of those contracts may tend to rise to the cost of the marginal renewable generator, and may therefore approximate a market-clearing model. Because prices are fixed at contract signature, however, the market-clearing contract price in this case would effectively be set by each solicitation and would then be fixed for generators selected under that solicitation for the duration of their contracts. Each solicitation or time period thereby would yield a new market-clearing-based long-term contract price.[64]

An alternative approach altogether is to assume an **average-cost** pricing model, which is likely to be most appropriate where longer-term (RECs, or RECs plus electricity) contracts are the predominant form of compliance (especially in still-regulated markets). Under this model, it is assumed that these long-term contracts are priced based on the actual cost of each renewable energy project (which will differ by technology), and are not influenced by the bid prices of other developers (see Figure 23). The total cost of RPS compliance is determined by the weighted average cost of all RPS resources, rather than by the marginal cost resource, leading to lower compliance and ratepayer costs.

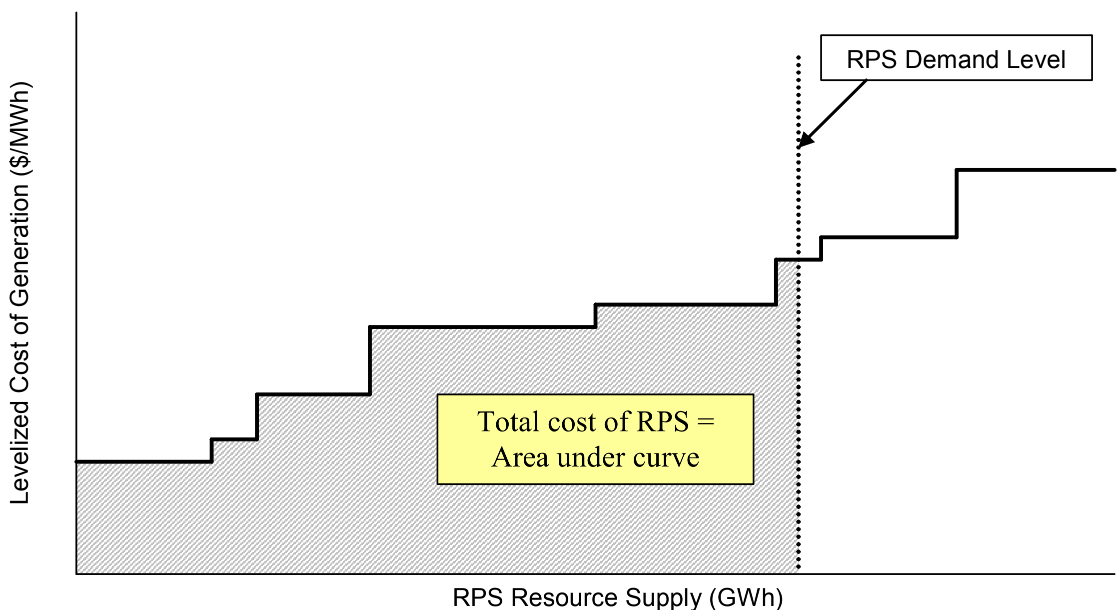

Figure 23. Graphical Representation of Average-Cost RPS Compliance Model

Figure 24 presents the number of studies that utilize the different approaches to characterizing the RPS market structure. Ten of the studies we reviewed adopt an average-cost approach for estimating RPS cost impacts. Another 14 studies adopt the market-clearing approach (including two studies that also use an average-cost approach in a different scenario). Those studies that take the market-clearing approach are typically those that analyze RPS policies in states with competitive electricity markets (e.g., Massachusetts, New York, and New Jersey). Of these

[64] With this method, the contract price received by an RPS generator is not affected by the marginal unit price in subsequent years.

studies, seven assume that the prices received by all renewable generators in any given year are determined by the price of the marginal renewable energy unit in that year, while the other seven use the longer-term contract-based market-clearing approach described earlier. A final six studies do not clearly take either the average-cost or the market-clearing approach. This is because in these cases a supply-curve method for characterizing renewable costs is not used, and these studies instead simply assume that all RPS-eligible resources are of the same cost in a given year.

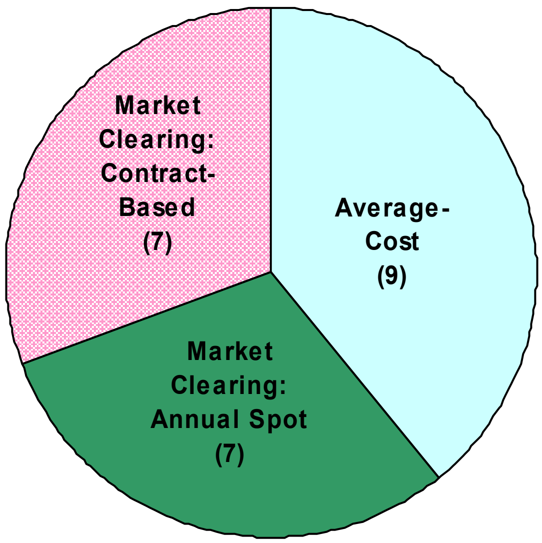

Figure 24. Approaches for Characterizing RPS Market Structure

Two studies, New York (DPS) and Vermont (Synapse), model RPS costs using both the market-clearing and average-cost methods.[65] These studies find that the two approaches can yield substantially different results: a retail cost increase of 0.39% (market clearing) vs. 0.13% (average cost) in the case of New York (DPS), and an increase of 0.84% (market clearing) vs. 0.33% (average cost) in Vermont (Synapse). The difference between market-clearing and average-cost results should be most pronounced when the renewable energy supply curve is sharply upward sloping.

Given the limited early experience with RPS markets, it is perhaps premature to judge the relative accuracy of these different cost-estimation assumptions. Considering the significant structural and regulatory variations among RPS compliance markets, it is also reasonable to expect that the average-cost approach will be more accurate in some states (especially still-regulated states where long-term contracting is prevalent), while the market-clearing approach will be better suited for others (competitive markets where short-term trade in RECs is common). In many instances, actual RPS contracting may resemble elements of each approach.

[65] New York DPS adopts the long-term contract approach to model the market-clearing scenario. The Vermont study adopts the spot market approach.

7. Modeling Renewable Technologies, Resources, and Costs

The renewable technology costs of an RPS policy are a function of the resource eligibility requirements of the policy, the presumed resource availability within the state or region (if out-of-state imports are allowed), the present and projected costs of the technologies, and the expected demand for renewable generation (which may include non-RPS-driven demand and/or out-of-state demand). In this section, we examine how the RPS cost studies in our sample have accounted for each of these factors. Section 7.1 identifies the technologies that are modeled by the studies, and whether renewable technology deployment is treated as an input or output of the studies. Section 7.2 and 7.3 describe the studies' methods for estimating resource availability and production cost, respectively. Section 7.3 also presents a few of the key renewable cost assumptions that are used by the studies.

7.1 Technologies Modeled

The number and type of renewable technologies considered in each RPS cost study is dependent on the resource eligibility provisions of the proposed RPS, the predicted degree of competition among different renewable resource options, the availability of existing resource assessment data, and the time and funding available to model different technologies. Table 6 shows the technologies that are modeled by each RPS cost study in our sample.[66]

Even if a technology is analyzed by an RPS cost study, it may not be expected to contribute to RPS requirements if its cost is expected to be too high or its resource potential is deemed too low. This is often the case with solar technology, which, despite being included in the technology assessments of many cost studies, is predicted by some of these studies to be non-economic compared to other technologies, and is thus assumed to contribute negligible generation towards meeting RPS targets.[67]

The simplest approach to estimating renewable resource availability is to assume the existence of sufficient resource potential of a single type of renewable technology to fully meet the RPS requirements with that single technology type. This is most commonly done for wind power, due to its abundant resource potential in many parts of the country as well as an expectation that it will be a least-cost renewable resource. Studies that rely on more detailed resource assessments are likely to model wind resources with much greater specificity, and may model both offshore and onshore sites of different sizes, each with varying cost and performance characteristics. As shown in Table 6, three of the studies in our sample only consider wind power. The majority of the studies, however, consider a wider variety of resource types. In addition to wind, studies regularly include landfill gas, photovoltaic and/or central station solar, and one or more biomass technologies. A smaller number of studies include geothermal, hydro fuel cells, anaerobic digestion, and MSW incineration. [68]

[66] Some studies model more detailed categories of renewable technologies than those shown in Table 6. For instance, NY (DPS) models hydro upgrades at existing facilities as well as new hydro facilities.
[67] Of course, studies that analyze RPS policies with solar set-asides, such as New Jersey (Rutgers) will predict a non-trivial amount of solar energy production, even if solar is not cost-competitive with other renewable technologies.
[68] A few studies also consider less commercial technologies, such as tidal or wave power. These technologies are not individually identified in Table 6, but they are included in the "Other" column.

Table 6. Technologies Modeled by Each RPS Cost Study

RPS Cost Study	Wind	Offshore Wind	Geothermal	Hydro	Landfill Gas	Biomass Direct	Biomass Co-Fire	Biomass Gasification	Anaerobic Digestion	MSW	Photovoltaic	Concentrating Solar Power	Fuel Cell	Other	Notes
AZ (PIRG)	✓		✓		✓	✓			✓		✓	✓			a,b
AZ (PEG)											✓				
CA (CRS)	✓		✓		✓	✓			✓	✓	✓	✓			
CA (Tellus)	✓		✓					✓			✓			✓	c,g
CA (UCS)	✓		✓		✓			✓			✓	✓	✓		d,e
CA LADWP (EC)	✓		✓		✓										
CO (PPC)	✓										✓	✓			
CO (UCS)	✓		✓						✓		✓	✓			c
HI (GDS)	✓		✓	✓							✓				
IA (WUC)	✓														
IN (EEA)	✓														
MA (SEA)	✓	✓			✓	✓	✓	✓					✓		f
MD (Synapse)	✓				✓	✓					✓				
MN (WUC)	✓														
NE (UCS)	✓														
NJ (Rutgers)	✓										✓				
NY (CCAP)	✓				✓		✓							✓	g
NY (DPS)	✓	✓		✓	✓	✓	✓	✓	✓		✓		✓		f
NY (ICF)	✓				✓		✓	✓			✓		✓		f
NY (Potomac)	✓	✓		✓	✓	✓	✓	✓	✓						
OR (Tellus)	✓		✓					✓			✓			✓	c,g
PA (B&V)	✓			✓	✓	✓	✓		✓		✓	✓	✓	✓	e,h
RI (Tellus)	✓			✓	✓			✓							c
TX (UCS)	✓			✓				✓			✓				c
VT (Synapse)	✓	✓		✓	✓	✓	✓		✓						
VA (CEC)	✓	✓		✓	✓	✓				✓	✓				a
WA (Lazarus)	✓		✓		✓		✓								
WA (Tellus)	✓		✓					✓			✓			✓	c,g
WA (UCS)	✓		✓	✓	✓		✓								
WI (UCS)	✓			✓	✓		✓	✓	✓						

Notes:
a - Study does not disaggregate biomass resource into different technologies, and may model other technologies in addition to direct biomass.
b - Based on text of report, we assume that the biomass technologies modeled in the study are biomass direct, landfill gas, and anaerobic digestion.
c - Study uses NEMS. The technologies listed here are only those specifically identified in the study, and do not represent all technologies implicitly considered within NEMS, which contains resource potential and cost assumptions for most of the technologies in the table above.
d - Based on text of report, we assume that the biomass technology modeled in the study is biomass co-firing.
e - Study models fuel cells running on renewable fuels.
f - Study models fuel cells running on non-renewable fuels (i.e. natural gas).
g - Study does not specify which technologies are included in "Other."
h - "Other" technologies considered are ocean energy (i.e. ocean thermal, wave, and tidal).

It is important to note that renewable technology deployment is an *input* assumption to some studies and a model *output* of others. The former approach is used by studies that assume that the entirety of the RPS generation requirement is met with a single type of technology: Arizona (PEG), Indiana (EEA), Iowa (WUC), Minnesota (WUC), Nebraska (UCS). In addition, a few other studies – Arizona (PIRG), Colorado (PPC), Maryland (Synapse), New Jersey (Rutgers), and Washington (Lazarus) – assume a specified RPS generation mix from the onset that consists of more than one technology type.[69] This approach lacks the analytical rigor of more sophisticated modeling approaches, but may be sufficient for a study whose primary focus is providing cost estimates, especially if only one or two technologies are expected to effectively determine the cost impacts of the RPS.

The other 17 studies in our review treat renewable technology deployment as a model output, i.e., the model "selects" renewable technologies in order of ascending cost until sufficient resources are developed to meet the RPS target. In addition to providing more credible estimates of the contribution of each renewable technology to meeting RPS goals, this approach also provides more precise (though not necessarily more accurate) estimates of the aggregate renewable production cost of the RPS policy. Such precision may be desirable when modeling an RPS policy whose cost impacts likely depend on the cost and availability of a number of different technologies.

7.2 Renewable Resource Characterization

RPS cost impacts are, to some degree, a function of the available renewable resource potential within a state or region. Though most of the RPS cost studies in our sample assume that only the most cost-effective renewable technologies will be built, there are limits to the resources that can be developed within a specific geographic area and time frame. Estimating the available renewable resource supply is thus an important component of most RPS cost studies.

The availability of a particular renewable technology is highly dependent on the geographic limits within which the resource potential for that technology is analyzed. These limits, which are prescribed by the RPS policy that is modeled, may be as small as a single state or as large as multiple NERC regions spanning several states and Canadian provinces.[70]

The methods and sources that the studies use to characterize renewable resource supply are as varied in complexity and detail as the general modeling approaches described in Section 6. As mentioned previously, some studies do not estimate renewable resource availability, and instead simply assume the existence of adequate supply to meet RPS targets at a given price point.[71] Occupying the opposite end of the spectrum are studies that perform original detailed resource assessments, sometimes analyzing wind speed data or quantifying the potential renewable

[69] In addition, one study – California LADWP (EC) – assumes a non-specified RPS generation mix of multiple technologies.

[70] Since non-hydro renewable power transactions have not regularly crossed international borders in North America, it is not clear whether such transactions, even if allowed, will actually result from RPS policies. A few cost studies predict that such imports will be used to meet RPS requirements (either in the base case or in a scenario analysis), but the likelihood of these transactions remains a source of uncertainty.

[71] This may be a defensible approach if the required amount of renewable generation is relatively low and the resource supply is known to be more than sufficient.

capacity at specific individual sites. The substantial regulatory, technical, and economic uncertainties affecting renewable resource availability and cost are such that renewable resource characterization is, by nature, a somewhat speculative exercise. Due to the considerable degree of guesswork involved and the potential for diminishing returns (in terms of predictive accuracy) from increasing specificity, it is unclear whether highly detailed resource assessments necessarily lead to significantly improved RPS cost estimates.

For the purpose of an RPS cost study, renewable resource assessments typically begin with a survey of existing estimates of resource potential in the state or region of interest. These estimates may come from government sources, such as the EIA, the National Renewable Energy Laboratory, or state energy agencies. Estimates are also sometimes done by consultants with expertise in analyzing resource potential, typically funded by public agencies.

Figure 25 identifies the principal sources of renewable resource availability data among the studies in our sample. Though many of the reviewed studies use data from existing resource estimates (some may also make adjustments to these estimates based on knowledge of the renewable energy market), some rely on primary research to develop original resource assessments. This research generally entails collecting market intelligence through interviewing renewable energy project developers, energy analysts, and other industry experts. At a more technical level, it may also include deriving resource potential estimates from existing data that is in another form; for instance, calculating potential wind capacity and capacity factors from wind speed data. Detailed original resource assessments can be costly, and the relatively small number of studies that perform such assessments is more likely due to the limited financial resources available for these studies than to an abundance of existing reliable data on renewable resource availability.

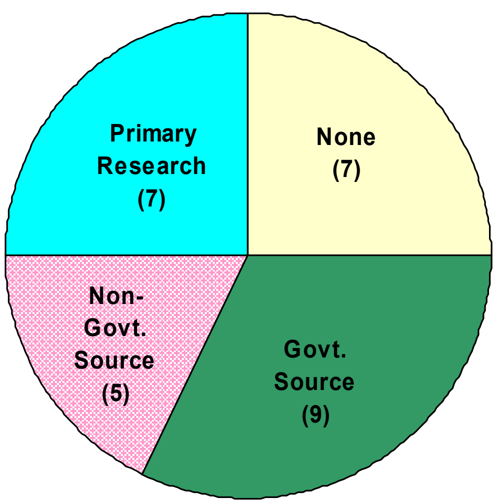

Figure 25. Principal Sources of Renewable Resource Data

7.3 Renewable Energy Cost Characterization

Renewable generation costs can be loosely divided into two categories: busbar and secondary. Busbar costs are the direct costs of a generation facility at the individual plant level, without accounting for any secondary effects that the plant may have on utility operations or transmission expansion. We start our discussion below on busbar costs, and cover secondary costs later in this section.

7.3.1 Sources and Methods for Estimating Busbar Costs

Figure 26 identifies the principal sources for busbar cost data among the studies in our sample. The most common are government estimates, such as from the EIA's Annual Energy Outlook or the EPRI/DOE Renewable Technology Characterization. As with resource potential, however, the studies employ a wide range of methods to estimate busbar costs, from simple top-down estimates derived from a single data source, to original bottom-up estimates requiring several input assumptions from multiple data sources.

As mentioned previously, many of the studies develop a renewable resource supply curve to estimate RPS cost impacts. These supply curves identify the quantity (either aggregate or incremental to the previous year) of RPS-eligible resources that are available at a given levelized cost in a given year. To avoid the potentially cumbersome task of creating supply curves for each year of the study timeframe, some studies construct supply curves for a few "snapshot" years, typically spaced at three- to five-year intervals.[72] The point at which the supply curve intersects RPS demand level in a given year determines the marginal cost resource. Depending on the assumed structure of the RPS, this marginal cost resource may in effect set the levelized price that all renewable resources are assumed to receive (a further discussion of this issue is provided in Section 6.2). When multiple resource tiers are included in an RPS proposal, a separate supply curve for each resource tier is required.

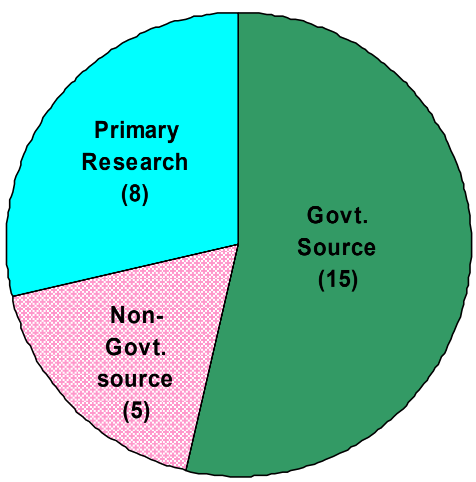

Figure 26. Principal Sources of Renewable Energy Busbar Cost Data

[72] Costs in interim years are then interpolated, or simply not estimated.

The majority (93%) of the studies we reviewed account for technology learning in some form (i.e., expected future reductions in renewable cost due to technological improvements). In some studies, however, these cost reductions are counterbalanced by expected cost increases as the best renewable resource sites are developed.

The busbar cost of renewable energy is a function of multiple input assumptions, including:

- capital cost
- operating and maintenance (O&M) cost
- fuel cost (if applicable)
- capacity factor
- finance terms and rates
- financial incentives

These assumptions can vary not only with time and region but also within a technology type. Not surprisingly, the assumptions differ considerably across the RPS cost studies we reviewed. Often, these variations can be explained by regional factors (e.g., higher wind capacity factors in windier states), by differences in financing structures (e.g., municipally owned vs. privately developed resources), or by expectations of technology cost and/or incentive availability that may vary according to when the study was completed.

The lack of agreement in renewable generation cost estimates points to a larger problem involving renewable resource data. As the renewable energy market continues to rapidly expand and evolve, the need for accurate, rigorous, and up-to-date estimates of renewable resource cost, performance, and potential is as important as ever. Unfortunately, the most commonly used data sources for these variables sometimes do not reflect the most recent knowledge about renewable technology performance and cost. As a result, the assumptions underpinning renewable cost and performance estimates in some studies may be dated, inaccurate, or inconsistent with current market conditions. RPS cost studies are not necessarily culpable for this, since developing better estimates of renewable cost and performance would require time and resources that are beyond the scope of many RPS cost studies. Such an ambitious undertaking would probably be best managed by a government research agency. The availability of better estimates of renewable cost and performance would improve the credibility of RPS cost analysis and lend more weight to economic analysis of renewable technologies in general.

Even if more accurate data sources were available, however, substantial uncertainties would still exist. Below, we provide a comparison of the assumptions for two key RPS cost drivers that underscores both the need for more current data and the uncertainties surrounding future renewable generation costs. These two key assumptions – wind capital cost and the duration of PTC availability – are specified in many of the RPS cost studies and, as evidenced in Figure 11 and Figure 12, both are potentially significant cost drivers. Though these two factors are among the most important determinants of RPS cost impacts, a more thorough review of the cost studies would need to evaluate other factors as well. However, because the many assumptions affecting renewable energy costs are often not explicitly provided in the cost studies, it can be difficult to unpack individual cost drivers.

7.3.2 Wind Capital Cost Assumptions

The assumed cost of constructing wind projects varies considerably among the reviewed studies (Figure 27).[73] Among the 17 studies that present these data, the highest capital cost estimate in the 2010-2015 timeframe (from Scenario 1 of the New York ICF study) is four times higher than the lowest estimate (from the Vermont study).[74] A majority of the studies use wind capital cost assumptions that are lower than EIA estimates from the 2006 Annual Energy Outlook; the median capital cost among the studies is $41/kW lower than the EIA estimate in 2010 and $71/kW lower in 2020.

Many of the studies assume that capital costs will gradually decline over time.[75] On the other hand, wind costs are endogenously modeled and actually increase over time in at least six of the reviewed studies: CA/OR/WA (Tellus), Colorado (UCS), New York (ICF), New York (CCAP), Rhode Island (Tellus), and Texas (UCS).[76] This is consistent with the idea that capital costs will increase in a given region after the best sites are developed, and therefore that capital costs are a function of installed capacity as well as time.[77] In some studies, the increase in capital cost with increased wind development significantly outweighs any learning effects that would otherwise reduce costs over time.

The assumed capital cost of wind projects can significantly affect the predicted cost of RPS policies. For example, a change in capital costs of $100/kW roughly corresponds to a $5/MWh change in levelized generation costs.[78] Of the studies reviewed here, most predict wind capital costs of under $1200/kW, and some predict long-term costs well below this figure. Notable is that current wind costs are reportedly in the $1400-2000/kW range, driven higher in recent months by adverse exchange rate movements, rising energy and steel prices, tight wind turbine manufacturing capacity, and a general rush to install wind projects while the PTC remains in place. As a result, the wind cost assumptions employed in most of the RPS analyses presented here do not accurately reflect the *current* cost to build a wind project. This disparity between

[73] Most of the capital costs shown here are "overnight" capital costs, which refer to the total construction cost if the wind farm could be built instantaneously, i.e., without including interest on the construction funds. In some cases, however, the capital costs presented may represent rolled-in capital cost, which include construction financing costs. None of these capital costs include transmission costs. Where studies provide estimates for capital costs for wind projects in different regions, we show cost estimates for projects within the region of the modeled RPS policy.
[74] The high capital cost assumption from Scenario 1 of the New York (ICF) study results from that study's reliance on EIA "cost adjustment steps," which multiply initial capital cost estimates by up to a factor of three to reflect expected resource degradation. We include the capital cost assumptions of both Scenario 1 and Scenario 2 of the study in Figure 27 because they are substantially different, and neither scenario is clearly identified as the base case.
[75] Several studies use current and projected wind capital cost estimates from EPRI/DOE Renewable Energy Characterization publications or from estimates published by the Government Performance Review Act (GPRA). Both of these sources project more aggressive cost reductions than those estimated by EIA.
[76] However, Colorado (UCS), New York (CCAP), and Texas (UCS) do not provide enough data to be included in the chart. Though Pennsylvania (B&V) does not endogenously model wind costs, the study applies a capital cost adder of $500/kW to 50% of the available wind resource (this cost adder is not reflected in Figure 27). It is unclear how much this more expensive wind resource is assumed to contribute to RPS requirements.
[77] These cost increases may also be reflected in some studies that do not endogenously model wind costs. These studies may assume that a certain fraction of wind resources are of higher cost than others. As the lower cost wind resources are used up, the higher cost resources are then developed, which may increase average wind costs over time.
[78] Assuming a simple capital recovery factor of 15% and a capacity factor of 34%.

study expectations and current market reality suggests that (all else being equal) the actual cost impacts of state RPS policies may exceed those estimated in our sample of studies, especially if higher wind costs persist.[79]

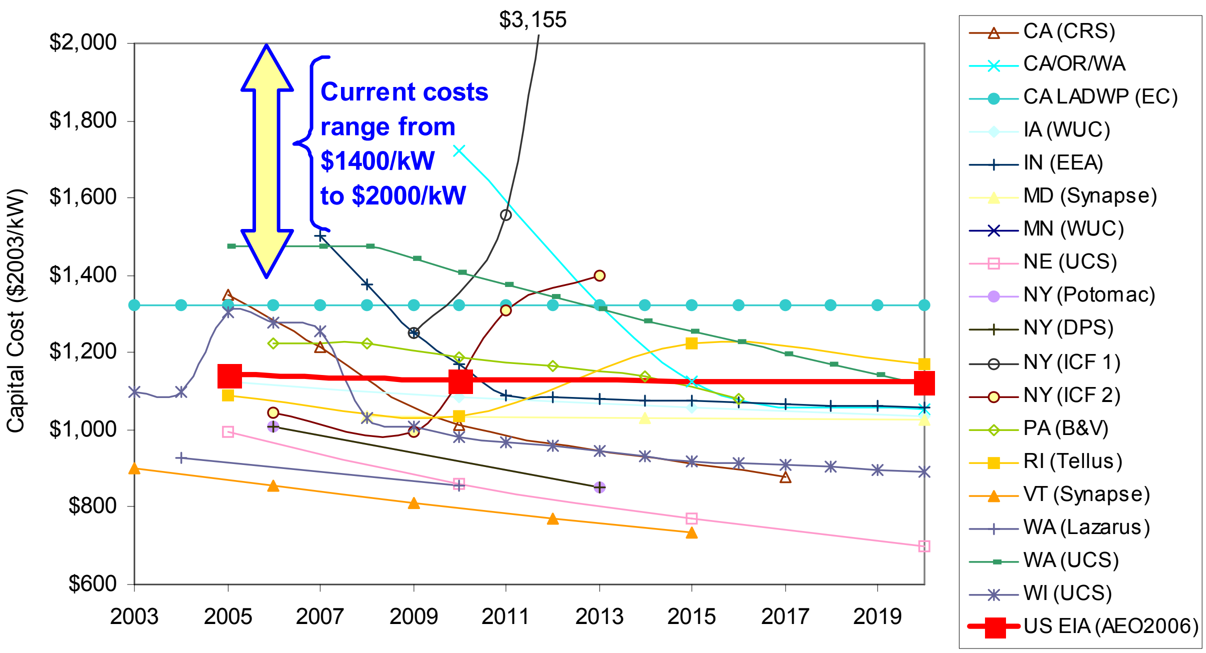

Figure 27. Wind Power Capital Cost Assumptions (Base-Case Analysis)

7.3.3 Federal Production Tax Credit Availability

The federal PTC can "buy-down" the cost of renewable energy by roughly $20/MWh on a long-term, levelized cost basis. As such, assumptions about the availability and level of the PTC can greatly impact the predicted cost of RPS policies.

Figure 28 illustrates the duration of PTC availability assumed by the studies in our sample.[80] The lack of consistency in these assumptions reflects the political uncertainty surrounding PTC extension. Given the changes in the status of the PTC over time, it is not surprising that an RPS cost study from 2002 (when existing legislation did not provide for PTC extension beyond 2003) might assume that the PTC would extend to a different year than an RPS cost study conducted in 2005 (when Congress extended the PTC through 2007).

[79] It is somewhat unclear whether this substantial increase in cost is a short-term phenomenon or if it marks a more permanent shift in the wind energy market. Some experts believe that a supply imbalance caused by the boom in turbine demand following the recent extension of the PTC is largely responsible for the recent cost run-up, but other factors (e.g., high steel prices, a weak U.S. dollar, or a move by manufacturers to increase profits to sustainable levels) may also be significant.

[80] In 2006, the inflation-adjusted PTC was worth 1.9 cents per kWh. The credit is available for the first 10 years of a plant's lifetime.

The final year of PTC availability is most commonly assumed to be 2006. The last six studies shown in the figure assume PTC availability throughout the entire timeframe of their analysis, while seven studies do not appear to include the PTC in their analysis at all.[81]

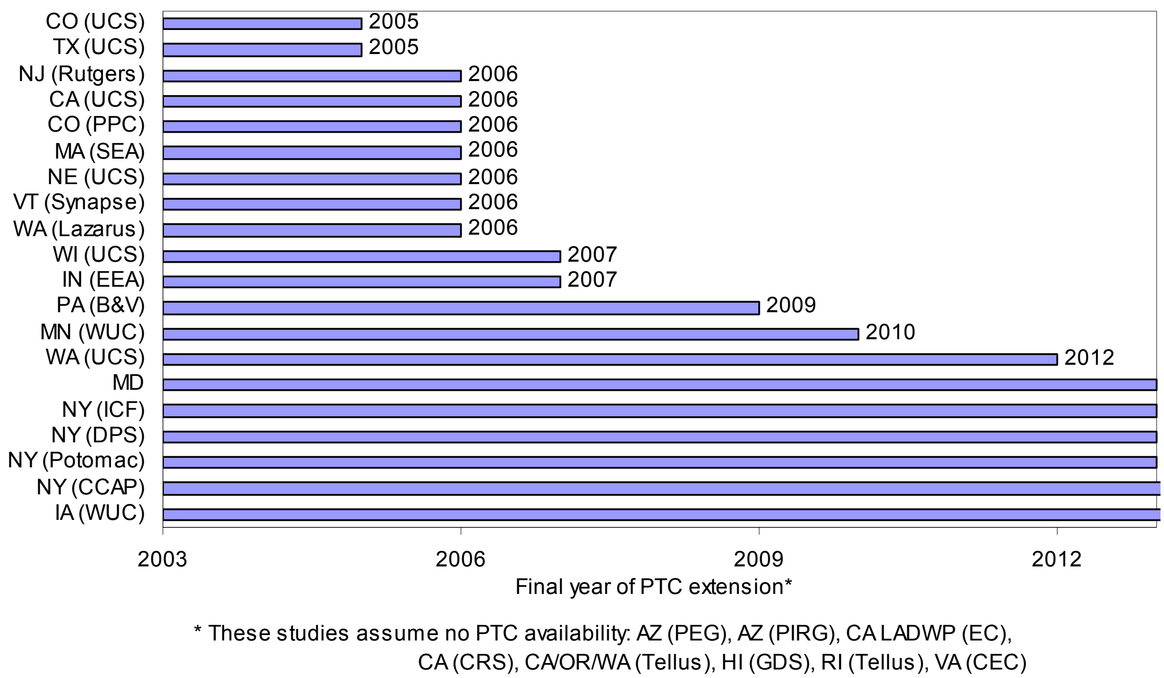

Figure 28. Duration of PTC Availability Assumed by RPS Cost Studies (Base-Case Analysis)

The studies are also not consistent in their assumptions of which specific technologies will qualify for the PTC. In addition to wind, some studies assume that the PTC is available for some or all types of biomass, including landfill gas. Though the PTC was recently extended through the end of 2008 and expanded to include geothermal, open-loop biomass, and other previously excluded resources, its long-term fate remains highly uncertain. Several studies have reflected this uncertainty in their analysis by modeling various PTC availability scenarios.

7.3.4 Treatment of Secondary Costs

To accurately reflect the true cost of renewable energy, it is not sufficient to only estimate busbar economics. Instead, a variety of secondary costs must also be considered: transmission costs, integration costs, resource adequacy or capacity costs (or capacity value), and administration and transaction costs. Table 7 identifies the studies that incorporate these costs into their calculation of overall cost impacts.

[81] Some of these studies do not consider the PTC because they exclusively model other renewable technologies (i.e., Arizona PEG solely considers solar technologies) or they assume that all wind energy is obtained through public power ownership (i.e., CA LADWP EC).

Table 7. Secondary Costs of Renewable Generation Considered by RPS Cost Studies

Cost Variable	Number of Studies	Studies
Capacity value	20	AZ (PEG), CA (CRS), CA/OR/WA (Tellus), CO (PPC), CO (UCS), IA (WUC), IN (EEA), MD (Synapse), MA (SEA), MN (WUC), NE (UCS), NY (CCAP), NY (DPS), NY (ICF), NY (Potomac), PA (B&V), RI (Tellus), TX (UCS), WA (UCS), WI (UCS)
Transmission costs	15	CA (CRS), CA (UCS), CA/OR/WA (Tellus), CA LADWP (EC), CO (PPC), CO (UCS), IA (WUC), MA (SEA), MN (WUC), NE (UCS), PA (B&V), TX (UCS), VT (Synapse), WA (UCS), WI (UCS)
Integration costs	12	CA (CRS), CA/OR/WA (Tellus), CO (PPC), CO (UCS), IA (WUC), IN (EEA), MN (WUC), NJ (Rutgers), TX (UCS), WA (Lazarus), WA (UCS), WI (UCS)
Administration & transaction costs	5	CA (UCS), MA (SEA), WA (Lazarus), WA (UCS), WI (UCS)

These costs can be significant, especially in regions with transmission constraints and aggressive RPS targets. They are especially relevant for wind power, which offers a variable production pattern from projects often located at some distance from load. The fact that many of the studies in our sample ignore many of these costs suggests that RPS cost-impacts may be underestimated by these studies, all else being equal.

Perhaps the most significant secondary cost, especially for wind power, is transmission. Transmission costs have become a significant constraint for many wind power project developers (see, for instance, CDEAC 2006). These transmission costs are extremely site-specific, however, and do not lend themselves to the simplifying assumptions that are often made to model other parameters. It is also not always clear what *specific* costs should be allocated to the cost of the RPS, especially in the event that transmission expansion would have been necessary to meet the needs of growing loads and conventional generators.[82] Roughly half of the cost studies in our sample include transmission in their analysis, but few if any of the studies analyze these costs in a detailed fashion.

As wind power penetration has increased, the question of how much dependable capacity wind power can provide to a system has taken on increased relevance. Wind projects do not offer the same value to an electricity system as a base-load coal plant or a dispatchable gas plant, but still provide some contribution to resource adequacy and therefore have some capacity value. Of the 20 studies that specifically analyze the capacity value of renewable energy, most assume that the capacity value of wind generation is likely to be commensurate with the expected capacity factor of these plants. Absent more detailed study, this approximation may not be a bad one, at least at relatively low levels of wind penetration (Giebel 2005).

Wind integration costs represent the combined impact of incorporating variable or "as-available" wind power into the grid. The science of understanding and quantifying the integration impacts and costs of wind power has solidified over the last several years, with most studies concluding

[82] See CDEAC (2006) for a detailed discussion of transmission cost allocation and recovery issues for wind generators.

that these costs represent only a small fraction of overall renewable production costs, typically under 0.5 ¢/kWh at levels of wind penetration as high as 10-20% (Bolinger and Wiser 2005; EWEA 2005; Smith et al. 2004). Only 12 of the studies in our sample include these potential costs in their analysis of RPS impacts.

Finally, a few of the RPS cost studies include administration and transaction costs that accompany RPS implementation, typically finding that these costs are expected to be small.[83]

7.4 Renewable Demand Characterization

Cost studies that use a supply curve to represent renewable resource costs and availability must also develop a renewable demand curve to estimate RPS rate impacts. The most basic version of such a curve would simply assume that all demand for renewable resources is driven by the RPS in question; in this case, yearly renewable energy demand is simply calculated by multiplying the RPS target percentage by the expected retail electric load of the year of interest.

This simplified approach, however, may well be inaccurate. In reality, multiple sources of demand for RPS-eligible renewable energy may exist. These sources include competing RPS policies from neighboring states, government agency green power commitments, and customer-driven green power programs. Of these demand drivers, existing or future RPS policies from neighboring states are likely to be the most significant in many regions. In a small Northeastern state such as Rhode Island or Vermont, this external RPS demand may dwarf the demand from the state's own policy. Especially in these regions, it is essential to develop estimates of *regional* renewable energy supply and demand, a task that can be greatly complicated by differences in the types of technologies that are considered eligible by each competing RPS policy.

Ignoring these other demands could yield a sizable underestimate of RPS costs if the renewable energy supply curve is sharply upward sloping. Seven of the cost studies we reviewed account for competing renewable energy demands from existing RPS (or other renewable incentive) policies in nearby states, while four consider customer-driven green power demand.[84] None of the studies considers the potential incremental demand that could come if other states in the region were to adopt RPS policies in the future.

[83] For example, California (UCS) expects these costs to vary from roughly 0.01% to 0.03% of total retail costs through the course of the study.
[84] One of these studies, New York (Potomac), implicitly accounts for out-of-state RPS and green power demand by using the renewable generation cost estimate developed in New York (DPS) (The latter study accounts for both demand sources).

8. Modeling Avoided Cost

The difference between renewable energy costs (busbar and secondary) and the cost of conventional power that would otherwise be used to meet load (avoided costs) determines the projected rate impacts of RPS policies. Depending on the approach, these avoided costs may be either an input or an output. If an input, then avoided costs are static, and are assumed to not be affected by increased renewables generation. In other words, wholesale market prices are the same in both the reference-case and RPS scenario. When avoided costs are a model output, on the other hand, incremental renewable generation may cause the wholesale market price to differ in the RPS scenario relative to the reference-case scenario.

Here we discuss three important elements of avoided cost calculations: (1) the general methodology that is used to estimate these costs, (2) temporal and geographic variations in avoided costs, and (3) the natural gas price forecast that is used.

8.1 General Methodologies

The most common method for estimating avoided costs is to use a conventional fossil-fuel plant proxy (Figure 29). The fuel type of this plant has typically been natural gas (7 of 13 studies), but some studies have estimated the cost using a mix of coal, gas, and other conventional generators (6 of 13 studies).[85] Estimating the levelized cost of the proxy plant typically requires input assumptions on capital and O&M costs, fuel prices, and financing terms. In most studies, the levelized cost of the proxy plant is assumed to set the long-term marginal wholesale price, which is then used as the long-run avoided cost forecast. In the short run, the avoided cost forecast is sometimes approximated using utility filings or forward market prices.[86] The fossil-fuel plant proxy approach is relatively simple and straightforward, but does not account for wholesale electric or natural gas price feedbacks, and may not be the preferred method for modeling RPS impacts in situations where these feedbacks may be important. The proxy plant method is also not well-tuned to analyze the wholesale market value of temporally-dependent renewable energy production profiles, though it can be substantially modified to approximate these values.[87]

[85] As natural gas prices have risen in recent years, it has become increasingly likely that renewable generation will offset coal production over time.
[86] There may also be an interim forecast period between the short and long run where market prices are interpolated.
[87] For example, the avoided cost estimate in one of the California studies (CRS) is based on the California Public Utilities Commission's avoided cost forecast methodology, the production cost component of which is based on the estimated cost of a new combined-cycle natural gas plant. The methodology then maps the hourly profile of a historical dataset of wholesale market prices to the long-run average cost of the natural gas plant to develop an hourly market price forecast

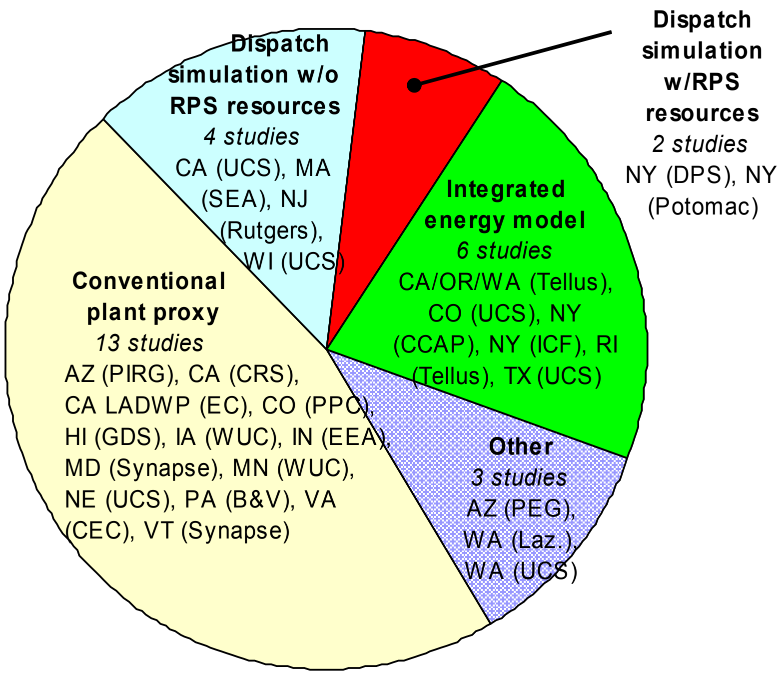

Figure 29. RPS Cost Study Methodologies for Estimating Avoided Cost

Six of the studies rely on dispatch simulation models to generate avoided cost forecasts. These models differ on one main point: whether or not RPS resources are included in the dispatch simulation. The California (UCS), Massachusetts (SEA), New Jersey (Rutgers), and Wisconsin (UCS) dispatch simulations model only the reference-case resource mix, and thereby provide a static avoided cost forecast.[88] On the other hand, the New York (DPS) and New York (Potomac) simulations model both the reference-case resource mix and the implied RPS resource mix, allowing wholesale market prices to vary between these two cases and therefore providing a dynamic avoided cost estimate.[89] Dispatch simulation models should be able to provide more specific and precise estimates of electricity system operating characteristics (such as hourly and seasonal market prices, hourly emissions, and displaced generation types) than would proxy-plant methods, but many of these characteristics can also be roughly estimated with relatively simple spreadsheet models.

Six of the studies employ an integrated energy model, either NEMS or IPM, to analyze potential cost impacts. These models are capable of endogenously determining fuel prices and capacity expansion, in addition to electricity prices. The avoided cost in this instance is not a direct output of the model – instead, the model calculates the entire electricity (or energy) system cost of the reference-case and RPS scenarios, and the incremental RPS cost is simply the difference between the costs of the two scenarios.

[88] The wholesale market price forecast used by the New Jersey study was determined in the New Jersey Renewable Market Assessment, prepared by Navigant Consulting and published in August 2004.

[89] In this case, RPS-eligible renewable resource types and generation costs are estimated externally to the dispatch simulation using a linear spreadsheet model, and renewable generators are modeled as zero-cost in the dispatch simulations.

Finally, three studies rely on alternative approaches altogether. Arizona (PEG) simply assumes that average retail rates will decline by 2% a year for the first 12 years of the study, and remain constant thereafter. Washington (Lazarus) assumes a constant avoided generation cost throughout the course of the study. Washington (UCS) bases its avoided cost assumptions on the "high fuel price" case of the Northwest Power and Conservation Council's Fifth Power Plan.

8.2 Temporal and Geographic Variations in Avoided Cost

The avoided costs of increased renewable generation are dependent on the timing of the displaced generation (i.e. peak, off-peak, summer, etc.) and, in some instances, the location of that generation. Twelve of the studies account for the time-differentiated value of renewable energy. This practice may be particularly important in regions of the country that experience high variability in diurnal and seasonal wholesale market prices, and where renewable energy output profiles are either especially well or poorly matched to those changes.

Only a few studies account for the geography of displaced generation within a specific state. The advent of locational marginal pricing in some regions of the country has improved our intuitive understanding of, and capability to model, geographically varying avoided costs. Only the Hawaii (GDS) and New York (DPS) studies actually model generator location, however.[90] Predicting the likely location of renewable resource additions requires a detailed resource assessment – a feature that is available to few of the RPS cost studies we reviewed.

8.3 Natural Gas Price Forecasts

In many studies, the most important input to the avoided cost calculation is the natural gas price forecast. This is due to two factors: (1) natural gas prices are highly uncertain, especially when compared to coal prices, making gas prices particularly difficult to predict; and (2) the majority of studies expect that increased renewable generation will largely displace natural gas-fired generation. The importance of the natural gas price forecast is also reflected by the relatively large number of studies that examine RPS cost sensitivity to natural gas prices, as discussed earlier in this report.

Figure 30 presents the delivered natural gas price forecasts used by the RPS cost studies in their base-case analyses (alternate price forecasts used in sensitivity scenarios are not included in the figure).[91] These forecasts reflect the upward shift in natural gas prices projections over the past several years, with most of the higher forecasts in the figure coming from more-recent studies. Though significant price discrepancies are apparent in the short term, projected prices converge to some degree in the longer term. The thick line marked by squares represents the EIA's 2006 forecast for average natural gas prices delivered to lower-48 electric generators. The EIA

[90] The other three studies (Colorado PPC, Colorado UCS, and Washington Lazarus) allocate aggregate RPS cost impacts to utilities according to utility-specific resource requirement provisions in the state's RPS legislation or by comparing a proportional amount of total incremental RPS generation costs to avoided cost forecasts that vary by utility.

[91] Not all of the reviewed RPS cost studies are represented in the figure. Some did not use a natural gas price forecast as a model input, and others did not provide the natural gas price data that they used.

forecast is close to the median value of the RPS cost study forecasts, at least in the later years of the forecasts.

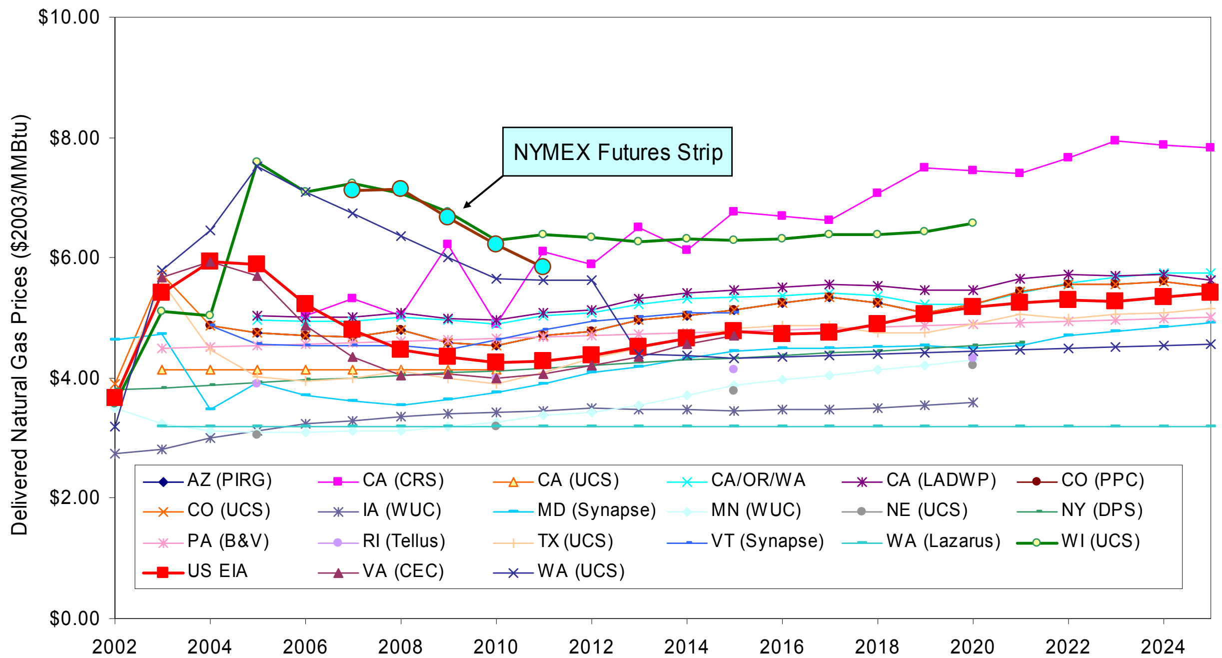

Figure 30. Base-Case Natural Gas Price Assumptions of RPS Cost Studies

Prices for 2007-2011 NYMEX natural gas futures have recently been trading at much higher levels than the vast majority of the forecasts shown in Figure 30.[92] As described in Bolinger et al. (2006), NYMEX futures prices – which can be locked in with certainty – offer a more-appropriate proxy for the avoided cost of fuel-free renewable generation than do uncertain fundamentals-based price forecasts. This suggests that the majority of the RPS cost studies we reviewed rely on natural gas price forecasts that are lower than what "should" be used, if the analysis was prepared today, at least for gas prices through 2011 and probably for later years as well. This has important implications for evaluating the results of the cost studies. As we note in Section 5.2.2, a change in natural gas prices of 20-25% can lead to a 0.5% impact on retail rates. Because many of the RPS cost studies predict retail rate impacts of less than 1%, this implies that an increase in natural gas prices of approximately $2/MMBtu relative to the base case – not an unreasonable expectation given current natural gas prices – could entirely offset the expected incremental cost of the RPS in a number of states.[93]

[92] The NYMEX data series was downloaded on November 24, 2006. Annual prices were estimated by averaging monthly prices (without weighting for consumption), and these estimated annual Henry Hub prices were converted to average wellhead prices for the lower 48 states using a method published by EIA (Budzik 2002). Wellhead prices were then converted to average delivered prices using the differential between average 2006 wellhead prices and delivered prices to electric generators in EIA 2006a.

[93] Of course, with higher natural gas prices, renewable energy is more likely to be competing with coal-fired generation in the future. Moreover, the effect of higher natural gas prices in mitigating potential RPS costs may be counterbalanced by other uncertainties that lead to higher-than-expected renewable generation costs. For instance, few of the reviewed studies predicted that wind capital costs would rise, rather than fall. If wind turbine costs remain at their current levels, it is possible that the unexpectedly high cost of wind generation will mitigate any cost advantages that renewable generation might have achieved under a scenario of high natural gas prices. The

9. Conclusions

With a few exceptions, the long-term rate impacts of RPS policies are projected to be relatively modest. Only two of the 28 RPS cost studies in our sample predict rate increases of greater than 5%, and 19 of the studies project rate increases of no greater than 1% (and six of these studies predict rate *decreases*). The median residential electric bill impact is +$0.38 per month. When combined with possible natural gas price reductions and corresponding gas bill savings, the overall cost impacts are even more modest, resulting in net consumer savings in at least one additional case.

Not surprisingly, wind power is expected to be the dominant RPS resource, comprising 62% of incremental RPS generation across the reviewed studies. The prevalence of wind suggests that wind generation costs (including transmission, capacity, and integration costs, as well as capital costs) are particularly important input assumptions to most RPS cost models.

The studies in our sample utilize a variety of modeling approaches, methods, and data sources to estimate RPS costs and benefits. A standard cost template has not yet emerged. This is in part due to regional differences in RPS policies and electricity markets, as different situations call for different modeling approaches. However, a more important factor may be the time and funding constraints imposed on individual studies. RPS cost studies are typically done with limited budgets on short timeframes, and the sophistication and detail of the analysis may largely be a function of these factors.

More-sophisticated models can account for interesting and potentially significant natural gas and wholesale electricity price feedbacks and may therefore be better-received by policymakers and RPS stakeholders. These models may also be better able to capture the benefits of increased renewable energy deployment. It is not entirely clear, however, that such models necessarily improve predictive accuracy. The assumptions for the primary and secondary costs of renewable energy, as well as the cost of conventional generation offset by increased renewable energy deployment, are likely of far more importance than the type of model used.

Though this report has focused most heavily on RPS-induced rate impacts, an increasing number of studies are modeling the macroeconomic or other public benefits of RPS policies, either in addition to, or exclusive of, rate impacts. Similarly, studies are increasingly evaluating the sensitivity of RPS costs to uncertain input parameters, and are considering the potential value of renewable energy in reducing certain electricity sector risks.

RPS cost studies are becoming more sophisticated, but improvements are still possible. Based on our review, we identify a number of areas of possible improvement for future RPS cost studies:

- ***Improved treatment of transmission costs, integration costs, and capacity values.*** Transmission availability and transmission expansion costs have become among the most important barriers to renewable energy in many states, but these costs are often poorly understood and imprecisely modeled in RPS cost studies. The capacity value of renewable

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uncertainties involved with predicting natural gas prices and wind capital costs (to name but two of a plethora of uncertain cost-driving factors) underscore the importance of performing scenario analysis.

energy (wind, in particular), as well as the cost of integrating renewable energy into larger electricity systems, are likewise emerging as potentially important variables, and studies analyzing RPS policies with relatively high incremental targets must be careful to properly account for these potential costs and impacts.

- ***More rigorous estimates of the future cost and performance of renewable technologies.*** As the renewable energy market continues to rapidly evolve and expand, the need for accurate, rigorous, and up-to-date estimates of renewable resource cost, performance, and potential is as acute as ever. Unfortunately, some of the most commonly used data sources for the cost and potential of renewable generation technologies are somewhat dated and arguably not up to the task. Developing better estimates of future renewable technology cost and performance would require time and resources that are beyond the scope of many RPS cost studies, and would probably be best managed by a government agency. The availability of such information would improve the credibility of RPS cost analysis and lend more weight to economic analysis of renewable technologies in general.
- ***Consideration of competing RPS requirements.*** As the number of states that have adopted RPS policies continues to grow, the available supply of renewable energy in regions with limited renewable potential (e.g., New England) may become more costly due to increased demand. Future cost studies would be well served to consider renewable demand from existing and potentially new RPS policies in neighboring states and regions and evaluate the potential effect of this demand on RPS rate impacts.
- ***Estimating the future price of natural gas.*** Where possible, base-case natural gas price forecasts should be benchmarked to then-current NYMEX futures prices (Bolinger et al. 2006). Furthermore, given fundamental uncertainty in future gas prices, a healthy range of alternative price forecasts should be considered through sensitivity analysis. To calculate the potential secondary impacts of increased renewable energy deployment on natural gas prices, either an integrated energy model or the simplified tool developed by Wiser et al. (2005) might be used.
- ***Evaluation of coal as the marginal price setter.*** With high natural gas prices, some states are shifting away from natural gas towards other resources, especially coal. A few of the RPS cost studies already assume that coal is the marginal fuel type that is offset by increased renewable generation, but most of the studies assume that natural gas will be the primary source of displaced electricity generation. New studies should more closely investigate the possibility that RPS generation may increasingly displace coal-fired and other non-gas-fired generation. Such a shift would likely reduce the importance of natural gas bill savings, but could also increase the importance of carbon emissions reductions.
- ***Greater use of scenario analysis.*** The inaccuracy of long-term fundamental gas price forecasts from the EIA and other private sector firms in recent years underscores the importance of using scenario analysis to bound possible outcomes. Not only is the future cost of conventional generation unknowable, renewable technologies themselves are experiencing rapid changes, both of which render the long-term impacts of RPS policies highly uncertain. Such uncertainty can be evaluated, to a degree, through greater use of scenario analysis. Some of the variables that may be most appropriate for scenario analysis include renewable technology potential and costs, future natural gas and wholesale electric prices, the period of PTC extension, and the potential impact of future carbon regulations.
- ***Consideration of future carbon regulations.*** As some states and regions begin to implement carbon regulations, renewable generators may stand to benefit. It is also possible that federal

carbon regulations will be developed within the time horizon of state RPS policies. Although these trends may significantly reduce the incremental cost of the renewable generation that is required by RPS policies, the risk of future carbon regulation has only been modeled by four of the studies in our sample. In future studies, we recommend that the risk of future carbon regulations be explicitly considered, at a minimum though scenario analysis.

- ***Accurate representation of RPS market structure.*** In some regions of the country, RPS compliance strategies based on short-term markets for RECs have led to unexpected cost impacts. All other factors being equal, markets in which electricity suppliers primarily rely on spot market REC transactions for RPS compliance may result in substantially different consumer cost impacts than markets that are dominated by traditional long-term contracting for renewables procurement. Where the former conditions apply, the market-clearing model should be used to estimate consumer costs. Where long-term contracts are more common, the average-cost model may be more appropriate for estimating these cost impacts. Future RPS cost studies should seek to adopt modeling approaches that are consistent with probable RPS market structures.
- ***More robust treatment of public benefits.*** Though an increasing number of studies have modeled macroeconomic benefits, the assumptions driving these analyses are often inconsistent, and the wide range of results may detract from the credibility of such studies. More work is needed to identify the most feasible and defensible assumptions governing the public benefits of renewable energy, including the fossil fuel hedge value of renewable energy and the benefits of reduced carbon emission, in addition to employment and economic development impacts.

Actual RPS costs may differ from those estimated in the RPS cost studies. The improvements listed above, if adopted, should lead to more accurate and realistic projections of the costs and benefits of state RPS policies in the future. In the meantime, it is difficult to assess whether the RPS impact studies reviewed in this report present overly optimistic or overly conservative estimates of future costs. Some of the assumptions in the RPS cost studies that may result in an underestimation of actual RPS costs include:

- Wind capital cost assumptions that appear too low in many cases, given recent increases in wind costs;
- Transmission and integration costs that are not fully considered in some instances;
- Use of an "average cost" model in some situations when a "market-clearing" model may be more appropriate;
- Lack of full consideration for the potential demand for renewable energy from other sources, such as demand from other state RPS policies;
- Increased likelihood that coal-fired generation will set wholesale market prices in some regions which, in the absence of carbon regulations, may make renewable generation less economic than when renewable energy is presumed to compete with natural gas; and,
- Expectations in some cases that the federal production tax credit (PTC) will be available indefinitely, which may be overly optimistic given the political uncertainty affecting PTC extension.

Conversely, a number of other cost study assumptions may result in an overestimation of actual RPS costs, including:

- Reliance on natural gas price forecasts that are almost universally substantially below current price expectations;
- Secondary natural gas and/or wholesale electric price reductions that have not been modeled in many of the studies;
- The potential for future carbon regulations, which are ignored in most of the studies in our sample; and
- Expectations in many cases that the PTC will only be available for either a very limited period or not at all, which may be overly conservative given the recent two-year extension of the PTC and the possibility for longer-term extension.

As states accumulate more empirical experience with actual RPS policies, future analyses should benchmark the cost projections from RPS cost studies against actual realized cost impacts as a way to both inform future RPS modeling efforts and better weigh the potential costs and benefits of state RPS policies.

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Appendix B. Base-Case Scenarios Chosen for RPS Cost Studies

Study	Scenario Chosen for Base-Case	Rationale
AZ (PEG)	Scenario 1, Option 1	Most similar to existing Arizona RPS
CA (LADWP)	"Renewables Above Gas/Coal Mix"	Cost results of this scenario are between the results of the other two scenarios
HI (GDS)	"9.5% RPS/Reference Oil Price Case"	Text of report appears to indicate that this is more likely scenario
IN (EEA)	Scenario 1	All other scenarios in the report are compared against this scenario
NY (DPS)	Average of "Market Clearing" and "Average Cost" approaches	Study does not indicate which scenario is more likely
NY (ICF)	Average of Scenario 1 and Scenario 2	Study does not clearly identify a base case scenario
RI (Tellus)	20% RPS target	Study provides complete set of sensitivity results for this target level, but does not provide complete sensitivity results for other levels
TX (UCS)	"TEPC Proposal, More Likely Scenario"	TEPC proposal of 10,000 MW by 2025 more closely resembles actual legislation
VA (CEC)	20% RPS, Low Imports	20% is the RPS target level currently being considered in the state legislature. To be conservative, "Low Imports" scenario chosen because it has higher cost impacts than "Low Natural Gas" scenario.
VT (Synapse)	"Vermont-Only renewables, Excluding Hydro-Québec"	Although text of report *appears* to indicate that Hydro-Quebéc resources are included in base case, the study provides more comprehensive results for the scenario in which these resources are excluded
WI (UCS)	"PTC to 2007 no CO2 savings"	Supplemental information provided by study authors identifies this scenario as the base case

Note: For studies not included in the table, the base-case is specifically identified in the cost-impact report.

Appendix C. Methodology for Converting Cost Results

In general, the cost studies provided cost results in at least one of the following formats:

1) Percentage changes in retail electricity rates
2) Monthly electricity bill impacts for typical customers
3) Cents/kWh retail rate impacts
4) $/MWh cost premium of RPS generation (RECs)
5) Annual cost premium/savings of RPS

As noted in Section 3.1, we have converted all cost results to the first three of these metrics. We consistently relied upon two data sources to perform these conversions:

- 2003 average monthly residential electricity consumption data and retail rates for each state, from EIA (2004)
- Projected average retail and residential electricity rates by Electricity Market Module (EMM) region from the EIA (2005) Annual Energy Outlook (AEO). Where necessary, we normalized these rates for each state according to the following formula:

  Expected retail rate in state in 20xx =

  $$\text{Projected retail rate in EMM region in 20xx} * \frac{\text{Average retail rate in state in 2003}}{\text{Average retail rate in EMM region in 2003}}$$

Specific calculation steps to arrive at percentage changes in electricity rates, monthly bill impacts, and cents/kWh retail rate impacts are detailed below (italicized terms represent variables mentioned above):

1) *Percentage changes in retail electricity rates*
To calculate percentage changes in retail rates, it was necessary to first calculate *¢/kWh* rate impacts (if they were not already provided by the cost study).[94] We converted *monthly bill* impacts to ¢/kWh by dividing them by average *residential monthly electricity consumption* figures from EIA (2004).[95] We converted *annual cost* impacts to ¢/kWh by dividing them by the projected electricity load (that is subject to the RPS) in the relevant year. We then calculated the percent change of this ¢/kWh rate impact from the *expected retail rate* in the relevant year.

2) *Monthly electricity bill impacts for typical customers*
To calculate monthly electricity bill impacts, it is also necessary to first calculate *¢/kWh* rate impacts. We converted *percentage changes* in retail rates to ¢/kWh by applying these changes to the *expected retail rate* in the relevant year. To convert other cost metrics to ¢/kWh, we followed the calculation steps outlined above. Once we estimated the ¢/kWh rate impact, we multiplied it by *average residential electricity consumption* to arrive at the monthly bill impact.

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[94] If the study provided projected REC prices instead of ¢/kWh retail rate impacts, we used RECs prices as a proxy for ¢/kWh.

[95] Note that this calculation yields the ¢/kWh impact for residential customers, which may, depending on the study's cost allocation assumptions, differ from the ¢/kWh impact for all retail customers. This difference, if it exists, is likely to be negligible.

3) *Cents/kWh retail rate impacts*
We converted other cost metrics to ¢/kWh retail rate impacts using one of the methods described in the two numbered items above.