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Costs and Benefits of Renewables Portfolio Standards in the United States

by

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Abstract

As state-level renewable portfolio standards (RPS) have driven large increases in U.S. renewable generation capacity, states have sought to quantify the costs and benefits of these policies. This paper examines recent costs and benefits of RPS implementation, focusing on the net (or incremental) cost to utilities of renewables used for compliance with RPS targets during the years 2010-2012. Incremental RPS cost estimates are developed using a wide variety of methods and assumptions, which makes comparisons among states imperfect. For states with restructured electricity markets, we use a standardized method to calculate incremental costs based on renewable energy certificate prices, alternative compliance payment levels, and compliance obligations. For states with traditionally regulated electricity markets, we rely on estimates produced by utilities and regulators, whose methods and underlying assumptions vary widely. We find that recent estimated incremental RPS costs were equivalent to less than 2% of retail rates in 17 states and about 2%–4% in eight states, or -\$4/MWh to \$48/MWh of renewable energy required across all states (for the most recent year available in each state). Estimated RPS costs in most states were well below the respective cost caps, although a few states are currently operating at or near their cap.

1. Introduction

Twenty-nine states, Washington DC, and Puerto Rico have adopted renewables portfolio standards (RPS), helping drive a roughly eight-fold increase in U.S. renewable generation capacity over the past decade. Concern over the impact of these policies on electricity prices and economic growth, however, has spurred recent legislation in at least a dozen states to repeal, reduce, or freeze existing RPS requirements. At the same time, other recent legislative proposals have sought to expand state RPS policies. Understanding the actual historical costs—and benefits—of RPS policies is critical to informing these legislative debates, but the subject is inadequately understood.

This paper examines historical costs of RPS implementation, drawing on a recent joint report by Lawrence Berkeley National Laboratory and the National Renewable Energy Laboratory, *Estimating the Costs and Benefits of Complying with Renewable Portfolio Standards: Reviewing Experience to Date* (Heeter et al. 2014).¹ We summarize the methods state agencies and utilities have used to assess RPS costs, compare incremental RPS compliance costs to date, and evaluate the potential for increases in RPS compliance costs as legislative targets rise and cost caps in some states potentially become binding. The aforementioned report also synthesizes recent estimates of broader societal benefits from formal state-agency evaluations—including estimates of health and emission reduction benefits, economic development benefits, and wholesale electricity market price reductions—though those findings are not included in the present paper. Compared to the summary of estimated RPS costs, the summary of RPS benefits is more limited, as relatively few states have undertaken detailed benefits estimates, and then only for a few types of potential policy impacts. In some cases, the same impacts may be captured in the assessment of costs. For these reasons, and because methodologies and level of rigor vary widely, direct comparisons between the estimates of benefits and costs are challenging.

2. Methods and Data Sources for Estimating Incremental RPS Compliance Costs

RPS compliance costs may be defined as either “gross costs” or “incremental costs.” Gross costs consist of the total cost of procuring renewables to meet the RPS, while incremental costs (also referred to as “net” or “above market” costs) represent

¹ This report is publically available at <http://emp.lbl.gov/publications>. Participation by Lawrence Berkeley National Laboratory was supported by the Office of Energy Efficiency and Renewable Energy (Solar Technologies Office) of the U.S. Department of Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH1131.

the difference between gross costs and the costs that would have been borne absent the RPS. We focus here on incremental costs, which represent a more-meaningful metric for assessing impacts on utilities and their ratepayers.

In general, our RPS cost-calculation methods depend on the manner by which load serving entities (LSEs) comply with RPS requirements, which in turn depends on the regulatory structure of the state. For states with restructured markets (i.e., with competitive retail markets), we estimate RPS compliance costs based on the cost of renewable energy certificates (RECs) and alternative compliance payments (ACPs).² For states with traditionally regulated markets, where incremental compliance costs must be imputed based on assumptions about what electricity generating resources would have been procured but for the RPS, we instead synthesize estimates of incremental RPS compliance costs published by utilities and regulators in those states. The following subsections further discuss the techniques and data sources used to estimate incremental RPS compliance costs, with the results presented in Section 3.

2.1. States with Restructured Markets

Load-serving entities (LSEs) in restructured markets typically meet RPS requirements by purchasing RECs, which represent the renewable energy “attribute”—in effect, the renewable energy “premium” above conventional power—and are often transacted separately from the underlying electricity commodity. Because LSEs in restructured markets typically do not have long-term certainty regarding their load obligations, they often purchase RECs primarily through short-term transactions, though longer-term (10- to 20-year) contracting for RECs has become more prevalent in recent years as a result of requirements or programs established to facilitate renewable energy project financing. Most states with restructured markets include an ACP mechanism whereby an LSE may alternatively meet its obligations by paying the program administrator an amount determined by multiplying the LSE’s shortfall by a specified ACP price (e.g., \$50/MWh). ACP prices serve, more or less, as a cap on REC prices, as LSEs generally would not pay more than the ACP rate for RECs.

Many RPS policies divide the overall RPS target into multiple resource tiers or classes, each with an associated percentage target. These typically consist of some combination of a “main tier” for those resources deemed to be most preferred or most in need of support (e.g., new wind, solar, geothermal, biomass, small hydro), one or more “secondary tiers” (e.g., for existing renewables that predate the RPS, large hydro, municipal solid waste), and a solar or distributed generation (DG) set-aside. REC pricing and ACP rates vary by tier, with the highest prices typically associated with the solar/DG set-aside, followed by the main tier, and the lowest REC pricing for the secondary tier. REC pricing also varies by state, depending on a great many factors (e.g., the stringency of the target, eligibility rules, REC banking provisions, etc.), though pricing may be correlated among states in a region (e.g., among New England states or Mid-Atlantic states) to the extent that renewable generators can sell RECs into multiple states in the region.

We estimate incremental RPS compliance costs for restructured markets based on REC and ACP prices and volumes for each tier.³ For several states, exceptions to (New York) or slight variations on (Illinois and Delaware) this approach are used.⁴ We translate these costs into \$/MWh by dividing by the amount of renewable generation required, and we translate them into a percentage of average retail electricity rates based on obligated LSEs’ retail sales and average statewide retail electricity prices published by the U.S. Energy Information Administration (EIA 2013).

For REC prices, we rely on PUC-reported data for the average price of RECs used for compliance in each year, where available. Those prices, which are often based on data reported confidentially by individual LSEs, are presumed to reflect the cost of all RECs retired to fulfill the RPS obligation in each year, including short-term purchases of varying durations as well

² In states with restructured markets, the traditional electric utility monopoly—where the utility provides generation, transmission, and distribution—has been split. Customers in restructured states can choose which electric service company will supply their generation. In traditionally regulated states, vertically integrated utilities provide generation, transmission, and distribution service to a captive market (i.e., franchise service territory). Although there is a spectrum of restructuring, for purposes of this study, we classify the following RPS jurisdictions as operating in restructured markets: Connecticut, Delaware, Illinois, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Washington DC.

³ Specifically, incremental costs are calculated according to: $C = \sum_{i=1}^n P_{REC,i} \times Q_{REC,i} + P_{ACP,i} \times Q_{ACP,i}$ where C is the calculated incremental compliance cost (in dollars) for a particular state in a particular compliance year (CY), n is the number of resource tiers within the RPS, P_{REC} is the average annual REC price, Q_{REC} is the number of RECs retired for RPS compliance purposes, P_{ACP} is the ACP price, and Q_{ACP} is the number of ACPs issued.

⁴ For New York, we calculate incremental RPS costs based on reported expenditures by the New York State Energy Research and Development Authority, which procures RECs on behalf of the state’s IOUs. Those expenditures consist primarily of costs to procure RECs for the main tier and the cost of incentive programs for the DG set-aside, as well as administrative costs. For Illinois, compliance costs for default service load are based on estimates reported directly by the Illinois Power Agency (IPA), which reflect the cost of RECs procured by IPA on behalf of default service customers. For Delaware, 2012 compliance costs for Delmarva Power & Light are based on surcharge collections, which are a direct pass-through of REC costs.

as RECs purchased under longer-term contracts. If PUC-reported REC price data were unavailable, we instead use the average of monthly spot market prices published by REC brokers (Marex Spectron for main-tier and secondary-tier RECs and a combination of sources for solar RECs [SRECs]). Broker-reported spot market data are supplemented, when possible, with REC pricing data for long-term contracts that may have been in effect during 2010–2012. Data on long-term contract pricing for New England states was provided by Sustainable Energy Advantage (SEA) and for Delaware was obtained from Delmarva Power & Light’s Integrated Resource Plans (IRPs).⁵ Volumes of REC retirements and ACPs are generally based on retrospective data published in utility or PUC compliance reports or otherwise obtained directly from PUC staff. ACP prices are typically established by statute or regulation; main-tier and secondary-tier ACPs generally are either fixed over time or increase with inflation, while solar ACPs often decline according to a pre-specified schedule. Further details on the data sources used to compute incremental RPS costs are summarized in Heeter et al. (2014).

Various limitations are inherent in our approach to calculating incremental RPS costs for restructured markets, including the following:

- **Omitted costs and savings:** REC and ACP costs do not capture the full range of costs and benefits to the LSE. Of particular note, integration costs and savings from reductions to wholesale energy market clearing prices are omitted. Wind integration cost studies have yielded a wide range of estimates, although generally less than \$5/MWh up to relatively high penetration levels (Wiser and Bolinger 2013). Wholesale market price reductions, in comparison, have often been estimated through modeling to be around \$1/MWh or less (for all generation in the market). However, this price-suppression benefit expressed as a fraction of renewable energy generation can be substantially larger in some cases, with estimates ranging from \$2/MWh to \$50/MWh.
- **Limited REC price transparency and liquidity:** Broker-published REC price indices may be a poor proxy for the average price of all RECs used for compliance. This may happen when a significant portion of REC transactions are occurring through long- or medium-term contracts and/or if broker prices are based on a small volume of transactions, in which case they may not even be representative of spot market prices as a whole. We attempted to mitigate these potential issues by relying, wherever possible, on PUC-published average REC prices and available long-term contract data. However, for some states and years, spot market index prices were the only available data and were therefore used in isolation (specifically, for Washington DC in 2012, New Jersey in 2012, Ohio in 2010, Pennsylvania in 2012, and Texas in 2010–2012).
- **REC price volatility:** REC prices—and hence RPS compliance costs derived from REC prices—can be volatile, with large swings from year to year depending on whether a state is under- or oversupplied. This fundamental feature of many RPS markets complicates and obscures cross-state comparisons and long-term temporal trends of RPS compliance costs. This volatility also underscores the importance of recognizing that REC prices in any particular year do not necessarily reflect the underlying incremental levelized cost of renewable generation.

2.2. States with Regulated Markets

In traditionally regulated states, utilities typically comply with RPS requirements through long-term power-purchase agreements (PPAs) with renewable electricity generators or build and own renewable-generation projects directly. Because expenses associated with long-term PPAs or utility-owned include both the cost of RECs and the cost of the underlying electricity commodity, determining the incremental cost of the renewable energy requires a comparison to the avoided cost of conventional generation that would have otherwise been procured, but for the RPS.

We do not develop independent estimates of incremental RPS costs for regulated states, but rather synthesize estimates published by utilities and regulators and translate those data into a common set of metrics for comparison. For most states, the cost data are derived primarily from utility compliance reports where RPS compliance costs are reported retrospectively, in some cases for ratemaking purposes and/or to demonstrate compliance with any applicable cost caps (see Heeter et al., 2014 for the list of data sources).

Utilities and public utility commissions (PUCs) in regulated states have used various approaches to calculating incremental RPS compliance costs, sometimes guided by statutory or regulatory guidelines.⁶ These approaches fall into three general

⁵ SEA provided data on long-term REC contract pricing based on its own internal research and analysis. For bundled contracts, SEA estimated the implied REC price premium based on a comparison of the bundled renewable PPA prices to market prices for energy and capacity.

⁶ Statutory or regulatory language related to cost calculation methodology can often be open to interpretation, resulting in differing methods across utilities within a state. As such, PUCs in several states—including California, Delaware, Minnesota, Oregon, and Washington—are currently engaged in processes to formalize or standardize RPS cost calculations (CPUC 2014, DE DNREC 2013, MN PUC 2013, PUC OR 2014, WA UTC 2013).

categories—comparison to a proxy conventional generator (e.g., a combined-cycle natural gas generator), comparison to wholesale electricity market prices, and modeling the electricity system with and without the RPS—each with its advantages and disadvantages. For example, using wholesale prices as the basis for avoided costs may be relatively simple and transparent analytically but may represent a poor counterfactual for the costs that the utility would have otherwise borne. Conversely, modeling approaches may more-realistically account for avoided costs and for system-level interactions (including integration costs), but often require large amounts of data and complex models that are not easily vetted among stakeholders.

Beyond the choice among those three basic approaches are a host of other key methodological issues that can also influence the magnitude of the resulting incremental cost, such as:

- Whether to include the cost of renewables procured prior to enactment of the RPS policy
- Whether and how to include indirect expenditures, such as integration, transmission, distribution, and administrative costs attributable to the RPS, which can be challenging given that many of those costs are associated with both renewable and non-renewable energy
- Assumptions about the operating life of renewable and non-renewable energy facilities, which can dramatically impact the calculated levelized cost of energy
- Whether costs are annualized in order to account for the “lumpiness” of renewable energy procurement
- Whether costs of energy efficiency programs are included, for those states where a portion of the RPS target may be met with energy efficiency

Given this background, several important caveats and complexities apply to the set of RPS cost estimates summarized for regulated states. First, data are wholly unavailable for a number of states (Hawaii, Iowa, Kansas, Montana, and Nevada) or are available for only a subset of utilities or years. Second, although we present data on a statewide basis, costs for individual utilities may differ from the statewide average. Where possible, we note within the text where variations among utilities in a given state are particularly significant. Third, as noted above, the methods and conventions used by utilities and regulators when estimating incremental RPS costs vary considerably and are often not completely transparent. The comparisons across states are thus imperfect, although, to the extent possible, we discuss qualitatively how methodological differences may affect the results. Finally, there are often disconnects in regulated states between the timing of RPS obligations and when costs are incurred. For example, utilities often procure renewable resources in advance of their compliance obligations, and some utilities provide up-front incentives for renewable DG. In general, the data we report represent costs incurred by utilities in each year and therefore correspond to actual renewable energy procurement in that year. For several states, however, the data instead represent the incremental cost of renewable energy applied toward the requirement in each year (which may differ both in quantity and in the underlying resources from the renewable energy procured in the same year). These differences in accounting methods are noted within the results, where relevant.

3. Results: Estimated Historical RPS Costs from 2010-2012

This section summarizes and compares incremental RPS compliance costs for 2010–2012, separately addressing states with restructured markets and those with traditionally regulated markets.⁷ Two metrics are used to describe incremental RPS costs:

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

Given the scheduled increases in RPS targets under current policies, we also discuss drivers impacting the trajectory of future RPS costs and the potential role of RPS cost-containment mechanisms in constraining cost growth (and limiting achievement of RPS targets).

3.1. States with Restructured Markets

As noted in Section 2.1.1, we use data on REC and ACP prices and volumes to estimate incremental RPS compliance costs in each state. In terms of cost per unit of renewable energy required, the costs range from well below \$10/MWh for some states and years to upwards of \$60/MWh in others. This variation partly reflects differences in REC and ACP prices across states

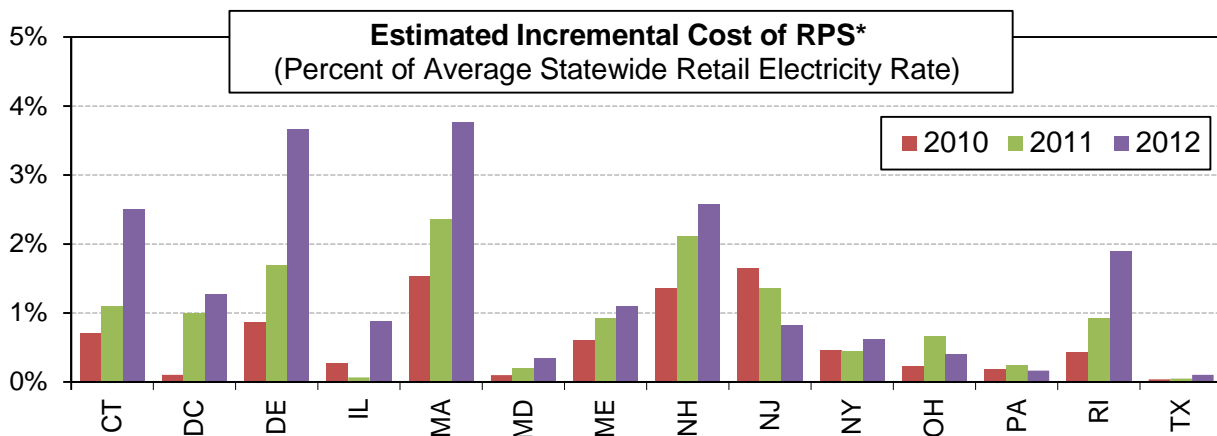
⁷ We examine a multi-year period to capture fluctuations in REC pricing and to expand the scope of states that can be included, given varying data availability in some states from year to year. As of this report writing, insufficient data for 2013 were available for inclusion.

and years. For example, low main-tier REC prices in Maryland, Pennsylvania, and Texas led to correspondingly low incremental RPS costs in those states (less than \$5/MWh during 2010–2012). Conversely, relatively high and progressively increasing main-tier REC prices among northeastern states underlie those states’ relatively high and increasing RPS incremental costs (rising to \$35–\$40/MWh in 2012). The highest compliance costs occurred in Ohio in 2011, with an average cost of roughly \$60/MWh across all tiers and all LSEs. The PUC subsequently ruled that one of the state’s utilities, FirstEnergy, substantially overpaid for RECs, and ordered the utility to refund its customers \$43.3 million for excess REC purchase costs over the 2009–2011 period (PUCO 2013b).

Differing mixes of resource tiers within each state’s RPS also drive incremental-cost variations. As such, RPS costs were generally low for states with large secondary-tier targets, as those tiers are typically characterized by low REC prices. The most pronounced example is Maine, where the secondary tier for existing resources constituted roughly 85%–90% of the overall RPS requirement each year, and where RPS compliance costs have been less than \$5/MWh. Conversely, states with higher solar set-aside requirements tended to have higher incremental RPS costs, because SREC prices generally have been relatively high compared to other tiers. For example, New Jersey and Washington DC had relatively high solar set-aside targets during 2010–2012, contributing to relatively high average incremental costs for the RPS as a whole (\$20–\$30/MWh) in some years. A precipitous decline in SREC prices during 2010–2012, however, tended to dampen the impact of solar requirements on overall RPS compliance costs and, in the case of New Jersey, led to a marked decline in average per-MWh RPS compliance costs.

Figure 1 expresses incremental RPS compliance costs as percentages of average retail electricity rates—the ratio of the dollar value of RPS compliance costs to total revenues from retail electricity sales in each year.⁸ Unlike compliance costs per unit of renewable energy required (in terms of \$/MWh), costs as a percentage of retail rates are tied directly to the size of the target (because higher targets, all else being equal, correspond to higher dollar costs associated with REC and ACP purchases) and are, in effect, normalized to each state’s retail electricity. To reiterate, compliance costs denoted in these terms are not necessarily equivalent to actual retail rate impacts (such as for states where ACP costs are not recovered from ratepayers).

As shown in Figure 1, incremental RPS costs in most states constituted less than 2% of average retail rates over the 2010–2012 period.⁹ In 2012, these costs averaged 1.4%, ranging from below 0.5% in many states to 3%–4% in Delaware and Massachusetts. That variation reflects the same fundamental underlying drivers discussed above (differences in REC pricing and the mix of resource tiers) as well as differences in RPS target sizes across states and over time. In most states, costs increased over this period as RPS percentage targets ramped up (the most notable exception being New Jersey, where declining SREC prices more than offset increasing RPS targets). We discuss in Section 3.4 considerations related to how RPS costs may evolve given continued increases in RPS targets over the next decade.



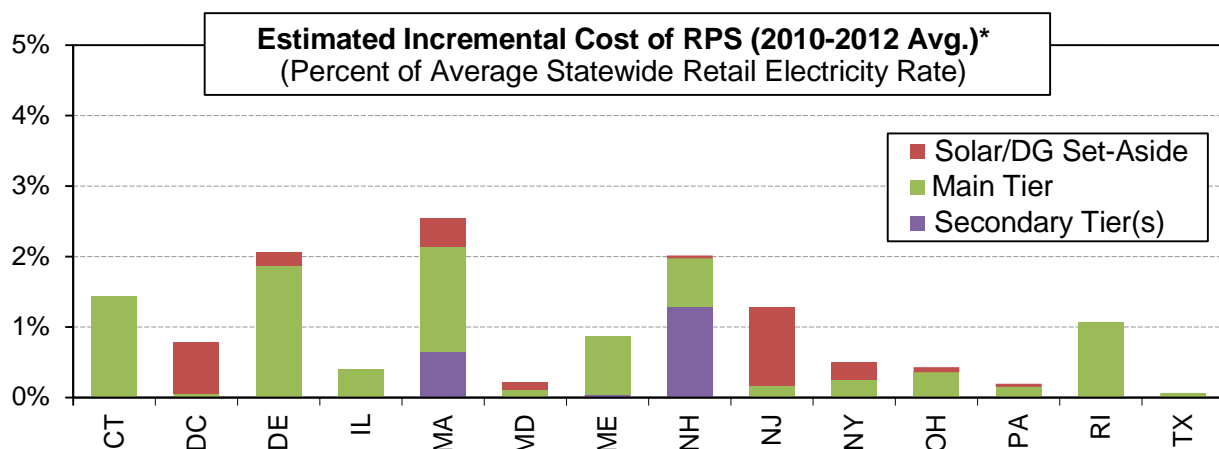
* Incremental costs are estimated from REC and ACP prices and volumes for each compliance year, which may differ from calendar years. If available, REC prices are based on average prices reported by the PUC (DC, IL, MD, ME, OH, NJ, PA); they are otherwise based on published spot market prices, supplemented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

⁸ Note that the years shown in Figure 1 and all subsequent figures correspond to each state’s definition of CY (compliance year), which begins on June 1 in Delaware, Illinois, New Jersey, and Pennsylvania.

⁹ Several of the states included in Figure 1 have independently published their own estimates of RPS compliance costs (CEEPP and R/ECON 2011, LEI 2012, NHPUC 2011, ME PUC 2012, ME PUC 2013, NJ BPU 2011, NYSERDA 2013b). Those analyses are often based on similar methods as used within the present study; thus, not surprisingly, the results are generally consistent.

Figure 1. Estimated incremental RPS cost over time in states with restructured markets (% of retail rates)

Figure 2 shows the contribution of each resource tier to incremental costs in each state, averaged over 2010–2012 to smooth fluctuations associated with large annual REC price swings. For most states, main-tier requirements represented the bulk of total RPS compliance costs, with notable exceptions. In Washington DC and New Jersey, which had both relatively high solar set-aside targets and relatively high SREC prices, solar set-aside costs constituted most of total RPS costs during 2010–2012 and about 1% of average retail electricity rates. New York’s DG set-aside constituted roughly 50% of total RPS costs. Secondary-tier shortages boosted REC prices in Massachusetts and New Hampshire, resulting in substantial costs associated with compliance with secondary-tier targets.



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

Figure 2. Estimated incremental RPS cost by tier in restructured markets (% of retail rates)

3.2. States with Regulated Markets

We synthesize estimates published by utilities and regulators as described in Section 2.1.2 to estimate total incremental RPS compliance costs in each state with a traditionally regulated market. In terms of cost per unit of renewable energy procured, the costs were generally near or below roughly \$20/MWh for six of the states for which information was available: Arizona, Colorado, Michigan, Oregon, Washington, and Wisconsin.¹⁰ These data are, in effect, the average above-market cost (i.e., implicit REC price) of the various contracts and projects procured for RPS obligations in each state, based on the particular method used by the reporting entity. Incremental costs in Wisconsin were somewhat higher (\$44/MWh) for the single year available (2010) because the Wisconsin Public Service Commission (PSC) estimated compliance costs using historical Midwest energy spot-market prices as the basis for avoided costs, and those market prices were particularly depressed in 2010 as a result of the economic downturn. In Oregon, average utility estimates of incremental compliance costs were actually slightly negative (-\$4/MWh); that is, RPS resources were determined to cost less, on a statewide average basis, than the proxy non-renewable resources that would have otherwise been procured.¹¹ In part, this reflects the integrated resource planning process in the state, through which the state’s two large utilities have procured cost-effective renewable resources on economic grounds, as well as opportunistic purchases of low-cost unbundled RECs.¹² Multiple RPS cost estimates were developed for California, using different avoided cost methodologies, with the derived incremental results ranging from -\$24/MWh (i.e., a net cost savings) to \$63/MWh in 2011 (the only year available).¹³

¹⁰ These values account only for resources procured for each state’s general RPS obligations (that is, excluding any solar or DG set-aside). We focus here on general RPS obligations because of the complications associated with calculating the incremental cost of DG set-asides in \$/MWh terms and lack of the requisite data. DG set-aside costs are, however, included in results discussed elsewhere, where RPS costs are presented as a percentage of average retail rates.

¹¹ Of the two utilities with compliance obligations in 2011–2012, only PacifiCorp estimated net cost savings from its RPS resources, while Portland General Electric estimated a slight increase in revenue requirements.

¹² The IOUs are allowed to meet up to 20% of their RPS obligation in each year with unbundled RECs.

¹³ The California PUC provided data on gross RPS expenditures for each of the state’s three IOUs, along with two sets of avoided-cost estimates that can be used to compute incremental costs (CPUC 2013). One set of avoided cost estimates is based on the state’s Market Price Referent (MPR), which is intended to estimate the all-in cost of a combined-cycle gas turbine and is used by the CPUC as a proxy for long-term electricity market prices when calculating the above-market costs of individual RPS contracts. The other set of avoided-cost estimates, which was provided by the utilities, is based on day-ahead California Independent System Operator (CAISO) energy market

In general, cost variations among the states resulted from different renewable energy costs (particularly different wind power costs), non-renewable power costs, and methods for calculating incremental costs. With regard to methods, relying on wholesale electricity market prices as the reference point for incremental RPS costs (as, for example, Wisconsin did) may capture fewer sources of avoided cost than the other approaches used, thereby resulting in somewhat higher RPS compliance cost estimates. In addition, relying on historical wholesale market prices as the basis for avoided costs can yield volatile results, given potentially wide fluctuations in wholesale electricity market prices from year to year. For example, the Wisconsin PSC estimated RPS compliance costs to be \$27/MWh in 2008 versus \$44/MWh in 2010, with the difference largely attributable to higher wholesale electricity market prices in 2008.

Figure 3 presents incremental RPS compliance costs for regulated states as percentages of average retail electricity rates. Using this metric (rather than the \$/MWh metric) yielded results for 10 states because of greater data availability. As explained previously, these data essentially represent the dollar value of annual compliance costs as a percentage of total retail electricity costs. Again, comparability across states is somewhat limited by the differences in methods and conventions used by the utilities and regulators that developed these cost estimates.

As shown in the left part of Figure 3, RPS costs during 2010–2012 were generally around or below 2% of average retail rates for most states, although these costs span a wide range. With negative incremental costs, Oregon is at the low end. Missouri also had very low costs because its utilities met all their non-solar obligations in 2011 and 2012 with banked RECs from renewable resources procured prior to enactment of the RPS, thus the data in Figure 3 represents only the cost of SREC purchases and solar rebates issued for compliance with the state’s solar set-aside. Note that, for both Oregon and Missouri, the data are based on the incremental cost of resources applied towards the RPS requirement in the years shown, but utilities in these states procured substantially greater amounts of renewables, banking the excess for compliance in future years.¹⁴

In Arizona, Colorado, and New Mexico, average incremental costs were 3%–4% of average retail rates in most years for several reasons. As shown in the right part of Figure 3, DG and/or solar set-aside requirements in those states constituted the bulk of total RPS compliance costs in most years. The apparently high cost of the DG set-asides is partially because the costs are heavily front-loaded: rebates and performance-based incentives are paid upfront (or over several initial years of production) in exchange for RECs delivered over each DG system’s lifetime. Those costs have declined somewhat over time, however, as utilities in these states have reduced incentive levels and moved away from upfront rebates. In addition, RPS costs in Colorado were relatively high because Colorado’s RPS procurement levels were substantially higher than the levels in other states shown in Figure 3. The state’s largest utility, Xcel Energy, attained renewable procurement levels equal to 15%–22% of retail sales during 2010–2012, compared to renewable procurement levels of 5%–10% in most of the other states shown.¹⁵ Arizona, unlike most other states, includes administrative expenses in its calculations, which add roughly 10% to total RPS costs for the years shown.

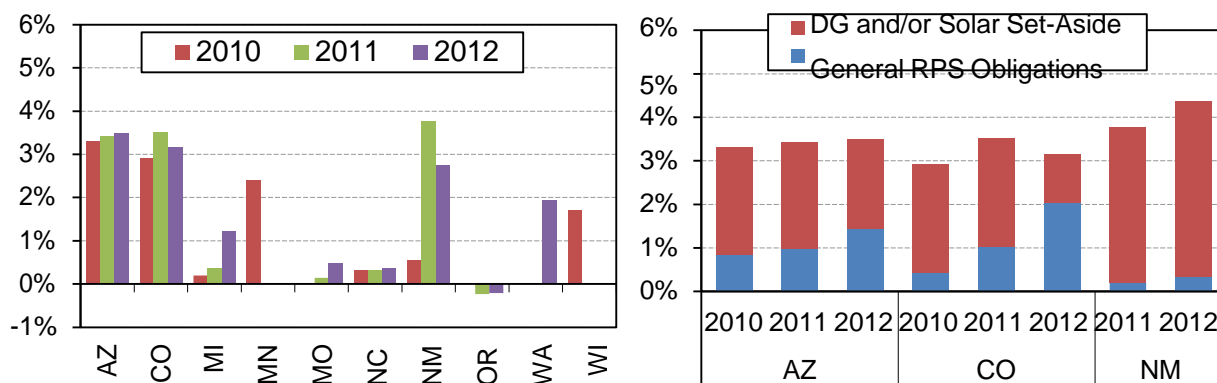
Importantly, the statewide averages presented in Figure 3 may mask variability in RPS costs among utilities within some states. In Washington, for example, all three IOUs as well as the state’s largest municipal utility reported costs for 2012 of around 0.5%–1.4% of retail rates, but many of the smaller publically owned utilities reported higher costs (in several cases as high as 8%–9%). Minnesota utilities reported 2010 RPS costs of 0.1%–8.6% of average retail rates (although most were around 1%–3%). New Mexico’s statewide averages are based on only two utilities, but those utilities reported divergent costs for 2012: 1.9% for Public Service Company of New Mexico versus 4.4% for Southwestern Public Service Company. In general, this intra-state variability is rooted in many of the same factors that drive differences in RPS costs across states—such as differences in procurement levels, resource costs, and cost-calculation methods—although determining the relative significance of these underlying drivers is typically not feasible.

prices and the cost of capacity in the CAISO market. These alternate avoided-cost estimates yield dramatically different incremental RPS cost results. Relative to the MPR, the incremental cost of the RPS in 2011 was negative (i.e., the RPS yielded net cost savings), equal to -\$24/MWh of renewable energy procured or -3.6% of average retail rates. In contrast, relative to short-term market prices, incremental RPS costs in 2011 were equivalent to \$43/MWh or 6.5% of average retail rates.

¹⁴ Data on the incremental cost of the renewable energy procured in each year are not available for Oregon or Missouri, but the available information suggests that those costs could, at least for some utilities, be less than the amounts shown in Figure 3, even though they would be based on a larger volume of renewable energy. In Missouri, for example, both Kansas City Power & Light and Kansas City Power & Light Greater Missouri Operations indicated that “all non-solar renewable additions caused revenue requirements to decrease” (KCP&L 2013, KCP&L GMO 2013); including those resources in the cost calculations would therefore reduce the estimated rate impact.

¹⁵ Incidentally, Xcel’s renewable energy procurement well exceeded its RPS targets during 2010–2012, which ranged from 5%–12% of retail sales. Thus, the company’s RPS costs for those years include costs associated with renewable energy credits banked for use in subsequent CYs, thus potentially reducing RPS procurement costs in those future years.

Estimated Incremental Cost of RPS*
(Percent of Average Statewide Retail Electricity Rate)



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

Figure 3. Estimated incremental RPS cost over time in regulated states (% of retail rates)

3.3. Future RPS Costs

RPS compliance costs during our analysis period were partly a function of the prevailing RPS targets during those years. Figure 4 summarizes RPS compliance costs for the most recent year available in each state. It shows the corresponding RPS targets or procurement levels in those years were 2%–22% of retail sales (the open circles), in most cases within 4%–8%.¹⁶ Although there is a relationship between compliance costs and the target or procurement level (e.g., Colorado had relatively high RPS procurement levels and high costs, while Ohio had a correspondingly low RPS target and low costs), other conditions also strongly affected compliance costs, including regional REC supply/demand balance, the presence of solar or DG set-asides, and cost-calculation methods.

During 2010–2012, U.S. average RPS compliance costs were equivalent to 0.9% of retail electricity rates when calculated as a weighted-average (based on retail-electricity revenues in each RPS state) or 1.2% when calculated as a simple average, although substantial variation exists around the averages across years and states.¹⁷ Going forward, RPS targets will rise, reaching their peak in most states during 2020–2025. These final-year targets, also shown in Figure 4 (the closed circles), rise to 7%–33% of retail sales, and to at least to 15% in most states. Compared to the most recent RPS targets or procurement levels, the final-year RPS targets constitute, on average, roughly a three-fold increase in RPS obligations. All else remaining constant, RPS costs as a percentage of retail rates should rise as renewable generation is added to meet the increasing targets.

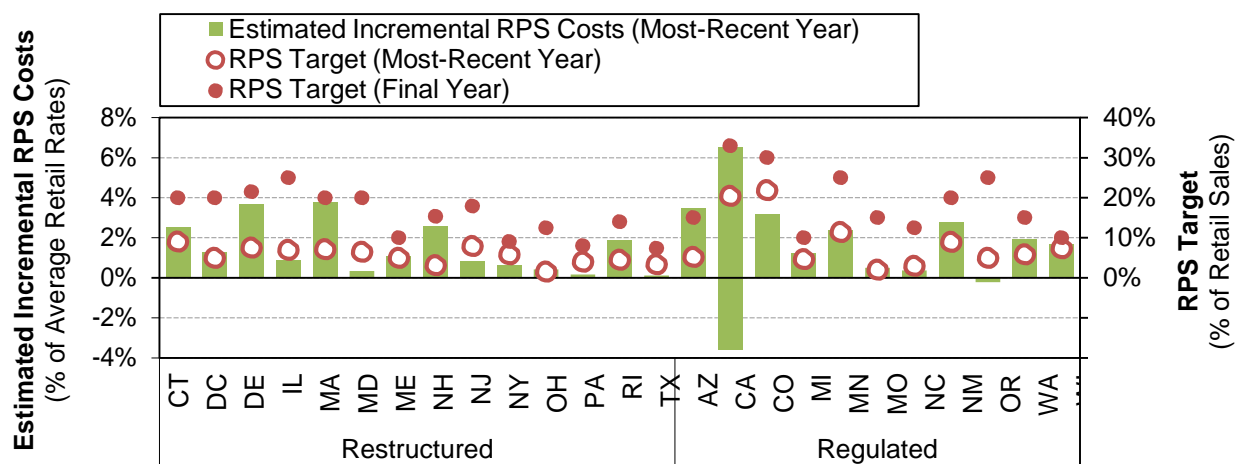
Whether and to what extent RPS compliance costs rise will depend on many factors. First, and perhaps foremost, is the underlying cost of renewable energy technologies, which might or might not continue to decline as it has in recent years. Second is the price of natural gas, because gas-fired electricity is generally the baseline against which market-based REC prices or the calculated above-market costs of renewables are established. Third, RPS costs may be affected significantly by changes to state and federal renewables tax incentives that reduce costs to utilities. Particularly important are the federal production tax credit, which (as of this writing) expired at the end of 2013, and the federal investment tax credit, which is scheduled to decline from 30% today to 10% in 2017. Fourth, environmental policies related to the power sector, such as federal greenhouse-gas regulations and air-pollution regulations, could have a significant impact on RPS costs by raising the cost of non-renewable resources and thereby reducing the incremental cost of renewables. Finally, future RPS costs could be affected by cost-containment mechanisms built into many state RPS policies that, if they become binding, would limit attainment of the RPS targets (see Section 3.5).

¹⁶ The open circles in Figure 4 represent somewhat different things depending on the state and are intended to be consistent with the corresponding cost data. For restructured states, the open circles represent RPS targets, because the costs are based on the total volume of REC purchases and ACPs. For most regulated states, the cost data represent the cost of RPS-eligible procurement (sometimes excluding preexisting RPS resources), and thus the open circles represent the corresponding quantity of RPS-eligible resources procured. For two regulated states, Oregon and Missouri, the cost data are instead based on only the cost of renewable energy applied towards the target, and thus the open circles represent the corresponding quantity of renewable energy.

¹⁷ California is excluded from the calculation of this average, given the lack of a single point estimate.

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

More recent prospective RPS cost analyses have estimated the following rate impacts for final target years: 10% in California (CPUC 2009), 2.2%–4.8% in Connecticut (CEEEP and R/ECON 2011), 7.9% in Delaware (DPL 2012b), 1.1%–2.6% in Maine (LEI 2012), 0.3%–1.7% for Northern States Power in Minnesota (Xcel Energy 2011), 2.2% for Great River Energy in Minnesota (Great River Energy 2011), and -0.5% (a reduction) in North Carolina (RTI International 2013).¹⁸ As with retrospective RPS cost analyses, the scope, methods, and assumptions vary widely among prospective cost studies, limiting their comparability to one another and to the historical cost data presented earlier. They nevertheless suggest a range of RPS cost changes in response to rising targets.



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

Figure 4. Estimated incremental RPS costs compared to recent and future RPS targets

3.4. Cost-Containment Mechanisms

Given the inherent uncertainty in future RPS costs, and the desire among policymakers to limit the potential burden to ratepayers, most RPS policies include one or more cost-containment mechanisms or “off-ramps.” Various approaches are used, the most common of which are ACPs and rate impact/revenue requirement caps:

¹⁸ For California, the estimated rate impact represents the projected increase in electricity costs to meet a 33% RPS in 2020 relative to a scenario in which gas-fired generation is used to meet all new resource needs. For Connecticut, the range in estimated rate impacts corresponds to varying REC price assumptions and represents the projected cost in 2020, relative to a scenario in which RPS targets are held constant at 2010 levels. For Delaware, the rate impact estimate is for the 2022/2023 CY rather than the final RPS target year (2025/2026). For Maine, the range in estimated rate impacts corresponds to varying REC price assumptions. For Northern States Power, the rate impact estimates represent the incremental cost of the company’s renewable energy standard compliance plan in 2020, relative to an otherwise least-cost plan, across several scenarios. For Great River Energy, the rate impact estimate represents the net present value of the increase in revenue requirements over the 2013–2027 period rather than the impact in the final target year and represents the percentage increase in wholesale prices to the company’s distribution utility customers. For North Carolina, the rate impact estimate represents the projected incremental costs in 2021 of the state’s RPS and other “clean energy policies”; the net cost savings are largely attributable to energy-efficiency savings used to meet a portion of the RPS requirements. In addition to the set of studies listed above, NYSERDA conducted a recent RPS evaluation, estimating that, for the 2002–2037 period, the state’s current RPS portfolio would yield a slight reduction in average retail rates, with wholesale market price reduction benefits more than offsetting REC purchase costs (NYSERDA 2013b).

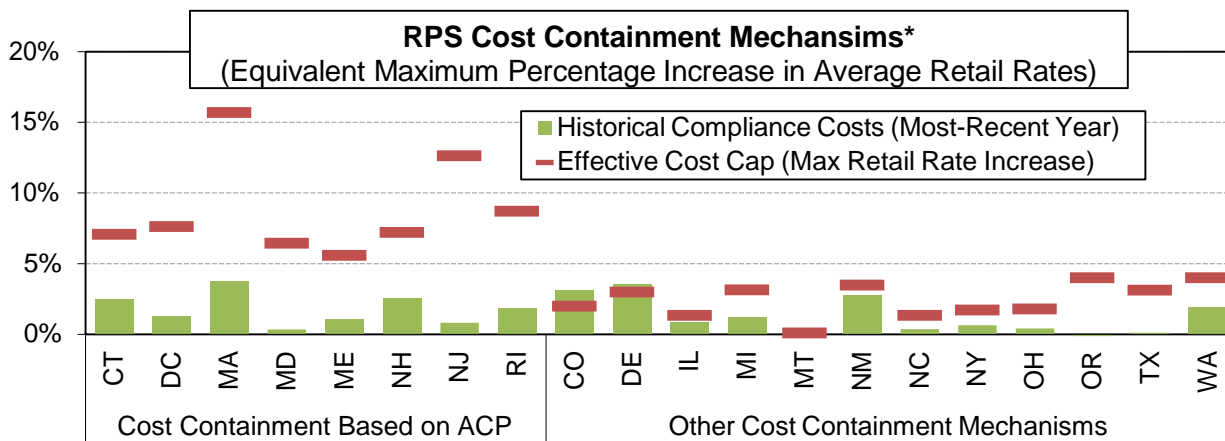
- **ACPs.** Typical of restructured markets, ACPs function as a backstop compliance option for LSEs. As such, they effectively cap REC prices and thus RPS compliance costs (although exceptions may exist, as discussed below).
- **Rate-impact/revenue-requirement caps.** Many states cap RPS costs in terms of a maximum allowed percentage of revenue requirements, costs, or customer bills. This kind of mechanism is most common among regulated states, but several restructured markets also use it in conjunction with ACPs. Caps generally apply to incremental RPS costs (although Kansas applies its cap to gross procurement costs), with various methods used to calculate the cost of RPS resources and avoided non-renewable resources.
- **Surcharge caps.** Two states, Michigan and North Carolina, have statutory caps on RPS surcharges, denominated in terms of a maximum dollar cost per customer. Colorado has a statutory rate impact cap of 2%, but the PUC has, in effect, operationalized this as a surcharge cap, allowing the utilities to incur costs beyond the cap and defer the balance.
- **Renewable energy contract price caps.** Caps may be placed on individual RPS contract prices. In Montana, RPS contract prices are capped based on the avoided costs of an equivalent non-renewable resource.
- **Renewable energy funding caps.** Where specific programs are established for the purpose of RPS procurement (e.g., New York), cost containment may occur through statutory or regulatory limits on program budgets.
- **Financial penalties.** Texas has a pre-specified penalty that can function largely like an ACP in terms of containing REC prices and incremental RPS costs. Other states may also levy financial penalties for non-compliance, but often those penalties cannot be passed through to ratepayers and/or the penalty rate is not pre-specified, thus they do not function as cost-containment mechanisms.

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

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

Figure 5 translates, where possible, state cost-containment mechanisms into the equivalent maximum percentage increase in average retail rates for the year in which each state’s RPS target reaches its peak.¹⁹ In effect, these values represent the maximum potential annual RPS cost, subject to the various caveats discussed above, for the single year in which each state reaches its final target. For comparison, Figure 5 also presents actual statewide-average RPS costs for the most recent historical year available (i.e., the same data presented in Figure 4).

¹⁹ Figure 5 excludes three states—Pennsylvania, Kansas, and Missouri—with numeric cost caps that cannot be expressed on a sufficiently comparable basis to the other states. Pennsylvania is excluded because the ACP rate for its solar set-aside is not pre-defined. Kansas’ cost cap applies to gross costs, rather than incremental costs. Missouri’s cost cap is currently subject to substantial debate, and a binding ruling on its interpretation has not yet been issued.



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

Figure 5. RPS cost caps compared to recent historical costs

States relying on ACPs as their primary cost-containment mechanism are grouped on the left side of the figure. Among those states, RPS costs are generally capped at 6%–9% of average retail rates.²⁰ The effective caps are higher in Massachusetts (16%) and New Jersey (13%) owing to relatively high solar set-aside targets and/or ACP levels.²¹ As shown in Figure 5, recent RPS compliance costs in these states are generally well below the cost caps; this is largely because the cost caps are arithmetically related to the final-year targets, and current RPS targets are well below those final-year targets. Going forward, however, rising RPS targets will put upward pressure on REC prices, which in many Northeastern states are already near their respective ACPs. At the same time, ACP rates generally will remain fixed (in either real or nominal terms) or, in the case of many states' solar ACPs, will decline over time. Of particular note, solar ACPs in Washington DC, Maryland, and Ohio are scheduled to decline to \$50/MWh, from current levels of \$350–\$500/MWh. This combination of possible upward pressure on REC prices and fixed or declining ACPs could constrain achievement of RPS targets and push total compliance costs toward the maximum levels shown in Figure 5. That might not occur if continued reductions in renewable energy costs and/or increases in wholesale power prices restrain growth in REC prices.

States with some form of cost containment other than, or more binding than, an ACP are grouped on the right side of Figure 5. Cost caps among these states are relatively restrictive, typically the equivalent of 1%–4% of average retail rates. Not surprisingly, cost caps have already become binding in several of these states. Utilities in New Mexico have, on a number of occasions, requested and been granted reductions in their RPS obligations to remain within the overall rate impact cap (termed the "Reasonable Cost Threshold") and/or to remain within the per-customer cost cap for large customers. Utilities in Missouri (not included in Figure 5) have sought waivers from solar rebate requirements included in the RPS law to remain within the state's cost cap.

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

²⁰ Although not included in the figure, Pennsylvania's main-tier and secondary-tier ACPs equate to an effective cost cap of 7.4% of average retail rates for the final target year. In comparison, RPS costs for the most recent historical year (2012) equated to 0.2% of retail rates.

²¹ Massachusetts' RPS does not have a single terminal year. For the purpose of constructing Figure 5, the cost cap was calculated based on the RPS targets in 2020. This is when the state's cost cap reaches a local maximum, after which it declines as the solar ACP rates decline and the SREC-I program expires.

Other states are approaching their caps. For example, Illinois, North Carolina, and Ohio have relatively low cost caps (1%–2% of average retail sales) and targets that rise considerably over the coming decade. In Oregon as well, cost caps may become an issue for some utilities, even though historical compliance costs have been low. Portland General Electric, in particular, has forecasted increases in its RPS rate impacts over the next 5 years that reach or exceed the 4% rate cap under a number of scenarios. New York is also likely to hit its cap, although this is by design because the cap is based on a schedule of revenue collections adopted by the PSC and deemed necessary for achievement of the target. In Montana, the cost cap effectively prohibits any net cost from RPS resources. Thus far, the cap has not been binding—no doubt due to the state’s high-quality wind sites—but the sheer restrictiveness of the cap suggests it could at some point become limiting.

Of the states on the right side of Figure 5, Texas and Michigan are both seemingly at low risk of reaching their cost caps, even though the caps are on par with other states within the group. In Texas, scheduled increases in the RPS target are relatively small, and installed renewable capacity in the state already well exceeds the final-year (2015) target. Given the low REC prices that have prevailed to date, RPS compliance costs in Texas thus would seem unlikely to approach the state’s cost cap. In Michigan, the cost cap is specified in terms of a maximum customer surcharge, and the state’s two large IOUs reduced their surcharges substantially in 2014. In their latest RPS procurement plans, both utilities project attainment of their RPS targets going forward, without any significant increase in surcharges (DTE Energy 2013, Consumers 2013).

4. Conclusions

We estimate that, in the most recent year with data available, incremental RPS costs were equivalent to less than 2% of retail rates in 17 states; in 10 of these states, estimated costs were equivalent to less than 1% of retail rates. In the remaining eight states we evaluated, incremental costs were equivalent to about 2%–4% of retail rates (including an average of the estimates for California). In terms of cost per unit of renewable energy required, average costs for the period ranged from -\$4/MWh to \$48/MWh across all states (for the most recent year available in each state). Most states have ways to contain RPS costs, typically through a retail-rate or revenue-requirement cap or by allowing ACPs. RPS costs in most states were well below the respective cost caps, although a few states were operating at or near their cap.

Across the literature, incremental RPS cost estimates are developed using a wide variety of methods and assumptions, which makes comparisons among states imperfect. For states with restructured electricity markets, we use a standardized method to calculate incremental costs based on REC prices, ACP levels, and compliance obligations. Key limitations to our method include omission of other potential policy costs, a lack of REC price transparency, and incomplete data on long-term contracts. Although REC prices reflect compliance costs, they do not necessarily reflect the cost of renewable technology deployment, because they can be strongly influenced by market supply and demand.

For states with regulated electricity markets, we rely on estimates produced by utilities and regulators. The results must be understood in the context of the wide variety of methods and assumptions these entities use to calculate costs. Modeling approaches provide detailed comparisons of the resource mix with and without an RPS, but input assumptions can significantly influence results. Simplified methods can provide useful cost perspectives but yield less comprehensive results. In various approaches, assumptions regarding plant lifetime and methods of annualizing costs can affect estimates substantially. The inclusion of costs associated with pre-RPS renewables can overestimate RPS costs, while inclusion of efficiency and indirect expenditures may complicate direct assessments of costs due to new renewable generation.

Future work could assess the costs and benefits of state RPS policies more comprehensively. Rather than examining incremental costs and benefits separately, improved analyses could compare costs and benefits directly using similar methods and levels of rigor. Additional work also could be done to standardize incremental cost calculations within and between states, given that incremental cost calculations are often required by RPS statutes. A few states are addressing standardization of incremental cost calculations. States in restructured markets might benefit from increased REC price transparency, particularly as those markets move toward greater use of long-term contracting. REC price transparency could be encouraged by requiring RPS-obligated entities to report REC prices on a confidential basis to the PUC; prices could then be publically reported on an aggregated basis.

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