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A SURVEY OF STATE-LEVEL COST ESTIMATES OF RENEWABLES PORTFOLIO STANDARDS

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ABSTRACT

This paper presents estimates of the incremental cost of renewables portfolio standards (RPS) during the years 2010–2012, assesses available cost-calculation methods, and evaluates potential future RPS compliance costs and the prospects for cost caps to become binding. We estimate that recent incremental RPS costs, per unit of renewable energy generation, ranged from -$4/MWh to upwards of $60/MWh, with costs in most states and years below $20/MWh. These estimated costs constituted less than 2% of average retail electricity rates in most states. Cost-containment mechanisms included within state RPS programs will limit future compliance costs to less than 5% of average rates in many states and to less than 10% in most others.

1. INTRODUCTION

Twenty-nine states and Washington DC have adopted renewables portfolio standards (RPS), helping drive a roughly eightfold increase in non-hydroelectric U.S. renewable generation capacity over the past decade. Concern over the impact of these policies on electricity prices, 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 estimates historical costs of RPS implementation, drawing on a recent joint report by Lawrence Berkeley National Laboratory and the National Renewable Energy Laboratory, *A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards* (1). We summarize the methods state agencies and utilities have used to assess RPS costs, compare estimated incremental RPS compliance costs over the 2010–2012 period, and evaluate the potential for future RPS costs to rise and for cost caps in some states to become binding. The aforementioned report also synthesizes estimates of broader RPS societal benefits, but 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, because 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 levels of rigor vary widely, direct comparisons between estimates of benefits and costs are challenging.

2. METHODS AND DATA SOURCES

We estimate *incremental* RPS costs—that is, the net cost to the utility or other load-serving entity (LSE) above and beyond what would have been borne absent the RPS. In general, our RPS cost-calculation methods depend on how LSEs comply with RPS requirements. For states with restructured markets, we estimate RPS compliance costs based on the cost of renewable energy certificates (RECs) and alternative compliance payments (ACPs). For states with traditionally regulated markets, where incremental compliance costs must be imputed based on assumptions about which 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 describe the techniques and data sources used to estimate incremental RPS compliance costs.

2.1. States with Restructured Markets

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, although longer-term (10- to 20-year) contracting for RECs has become more prevalent recently. 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, because 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 solar/DG set-asides, followed by main tiers, and the lowest REC pricing for secondary tiers. REC pricing also varies by state, depending on many factors (e.g., the stringency of the target, eligibility rules, REC banking provisions, etc.). Pricing may be correlated among states in a region 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.[1] For several states, exceptions to (New York) or slight variations on (Illinois and Delaware) this approach are used. 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 (2).

For REC prices, we rely on data reported by public utility commissions (PUCs) 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 as RECs purchased under longer-term contracts. If PUC-reported REC price data are unavailable, we instead use the average of monthly spot market prices published by REC brokers (Marex Spectron for main-tier and secondary-tier RECs and a combination of sources for 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 and for Delaware was obtained from Delmarva Power & Light's Integrated Resource Plans. 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. (1).

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.
- **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. We relied when 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.
- **REC price volatility**: Year-to-year REC prices—and hence RPS compliance costs derived from REC prices—can be volatile, complicating and obscuring

[1] Costs are calculated as: $C = \sum_{i=1}^{n} \left(P_{REC,i} \times Q_{REC,i} + P_{ACP,i} \times Q_{ACP,i} \right)$ where C is the calculated incremental compliance cost (in dollars) for a particular state in a particular compliance year, 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.

cross-state comparisons and long-term temporal trends of RPS compliance costs.

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 ownership 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 without the RPS.

We do not develop independent estimates of incremental RPS costs for regulated states. Rather, we 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; Heeter et al. (1) list the data sources.

Utilities and PUCs in regulated states have used various approaches to calculate incremental RPS compliance costs, sometimes guided by statutory or regulatory guidelines. These approaches fall into three general 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 account for avoided costs and system-level interactions (including integration costs) more realistically but often require large amounts of data and complex models that are not easily vetted among stakeholders.

A host of other methodological issues also can influence the magnitude of the resulting incremental cost, such as:

- Whether to include the cost of renewables procured prior to enactment of the RPS
- Whether and how to include indirect expenditures, such as integration, transmission, distribution, and administrative costs attributable to the RPS
- Assumptions about the operating life of renewable and non-renewable energy facilities
- Whether costs are annualized to account for the "lumpiness" of renewable energy procurement
- Whether costs of energy-efficiency programs are included, for states in which some of the RPS target may be met with energy efficiency

Given this background, several important caveats and complexities apply to the RPS cost estimates summarized for regulated states. First, data are wholly unavailable for a number of states 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. Third, the methods and conventions used by utilities and regulators vary considerably and are often not completely transparent. The comparisons across states are thus imperfect. 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 correspond to 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).

3. RESULTS: ESTIMATED RPS COSTS, 2010–2012

We compare RPS compliance cost estimates across states in terms of two metrics:

- Dollars per megawatt-hour ($/MWh) of renewable energy required or procured, representing the average incremental cost of RPS resources relative to conventional generation
- Percentage of average retail electricity rates, representing the dollar magnitude of incremental RPS costs relative to the total cost of retail electricity service (generation, transmission, and distribution)

In addition to presenting historical cost estimates, we also discuss drivers of future RPS costs and the role of RPS cost-containment mechanisms in constraining cost growth (and limiting achievement of RPS targets).

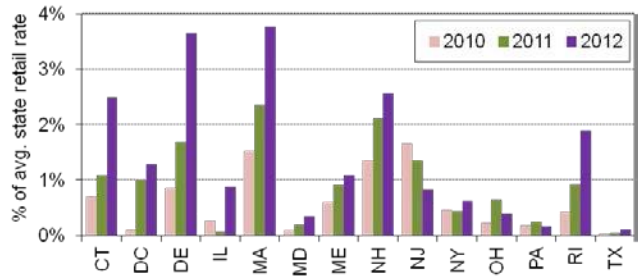
3.1. States with Restructured Markets

The costs in restructured markets ranged from well below $10/MWh for some states and years to upwards of $60/MWh in others, partly reflecting differences in REC and ACP prices across states 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 increasing main-tier REC prices among northeastern states led to correspondingly high and increasing RPS incremental costs in those states (rising to $35–$40/MWh in 2012). In Ohio, compliance costs in 2011 averaged roughly $60/MWh. The PUC recently 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 during 2009–2011 (3).

Differing mixes of resource tiers within each state's RPS also drive incremental-cost variations. RPS costs were generally low for states with large secondary-tier targets, because those tiers are typically characterized by low REC prices. In Maine, the secondary tier for existing resources constituted roughly 85%–90% of the RPS requirement each year, and RPS compliance costs have been less than $5/MWh. States with higher solar set-aside requirements tended to have higher incremental RPS costs, because SREC prices generally have been 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 RPS costs ($20–$30/MWh) in some years. The precipitous decline in SREC prices during 2010–2012, however, dampened the impact of high solar requirements on RPS compliance costs and, in the case of New Jersey, led to a marked decline in average per-MWh RPS compliance costs over that period.

Figure 1 expresses incremental RPS compliance costs as percentages of average retail electricity rates, i.e., the impact of RPS compliance costs on retail electricity prices and consumer electricity bills were those costs passed fully and immediately to customers. Measured in terms of this metric, incremental RPS costs constituted less than 2% of average retail rates in most states during 2010–2012. In 2012, RPS costs averaged 1.4% of retail rates, ranging from below 0.5% in many states to 3%–4% in several others.

Unlike per-MWh compliance costs, costs as a percentage of retail rates are related to the size of the target: all else being equal, higher targets correspond to higher dollar costs associated with REC and ACP purchases. It is for that reason that, in most states, costs increased over the period shown, as RPS percentage targets simultaneously rose. Similarly, some portion of the variation in costs across states can be attributed to the varying stringency of 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 NYSERDA's annual RPS expenditures and estimated REC deliveries.

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

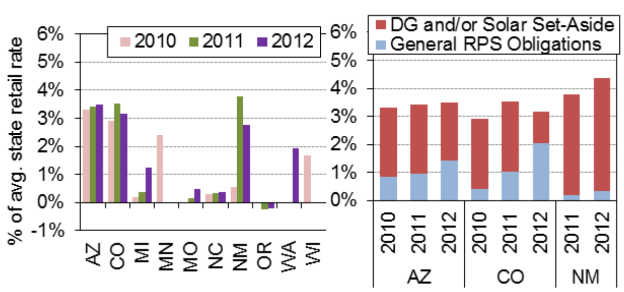
3.2. States with Regulated Markets

In traditionally regulated markets, compliance costs for general RPS requirements (i.e., excluding any solar or DG set-asides) were generally near or below roughly $20/MWh, ranging from -$4/MWh in Oregon (2011 and 2012) to $44/MWh in Wisconsin (2010). Cost variations among states partly resulted from different underlying renewable energy costs, but also reflected differences in the methods used to calculate incremental costs. For example, the Wisconsin Public Service Commission estimated incremental costs using historical energy spot-market prices as the basis for avoided costs; those market prices were depressed in 2010, owing to the economic downturn, which resulted in relatively high calculated incremental RPS costs. Multiple RPS cost estimates were developed for California, using different avoided-cost methods, with the derived incremental results ranging from -$24/MWh (i.e., a net cost savings) to $63/MWh in 2011 (the only year available).

Figure 2 presents incremental RPS compliance costs for regulated states as percentages of average retail electricity rates. As shown in the left part of Figure 2, RPS costs during 2010–2012 were generally around or below 2% of average retail rates for most states. With negative incremental costs, Oregon is at the low end. Missouri also had very low costs because its utilities met all of their non-solar obligations in 2011 and 2012 with banked RECs from renewable resources procured prior to enactment of the RPS (for which incremental cost was deemed to be zero). For 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.

Estimated costs for Arizona, Colorado, and New Mexico were somewhat higher, averaging 3%–4% of average retail rates in most years, for several reasons. As shown in the right part of Figure 2, 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 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 2. 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.

The statewide averages presented in Figure 2 mask some variability in RPS costs among utilities in a number of states. In Washington, for example, all three investor-owned utilities and the state's largest municipal utility reported 2012 costs of around 0.5%–1.4% of retail rates, but many of the smaller publically owned utilities reported higher costs (as high as 8%–9%). Minnesota utilities reported 2010 RPS costs of 0.1%–8.6% of average retail rates (most were around 1%–3%). New Mexico's statewide averages are based on only two utilities, which reported costs of 1.9% and 4.4% in 2012. In general, this intra-state variability is rooted in many of the same factors that drive differences in RPS costs across states (e.g., the cost and type of renewable energy resources procured, methodological differences, etc.).



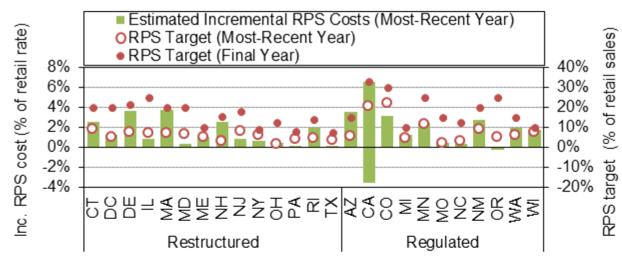
Incremental costs are based on utility- or PUC-reported estimates and are based on either RPS resources procured or RPS resources applied to the target in each year. Data for AZ include administrative costs, which are grouped in "General RPS Obligations" in the right-hand figure. Data for CO are for 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).

Fig. 2: Estimated incremental RPS cost over time in regulated states (% of retail rates)

3.3. Future RPS Costs

RPS compliance costs were partly a function of the prevailing RPS targets during our analysis period. Figure 3 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 ranged from 2%–22% of retail sales (the open circles), though in most cases were within 4%–8%. Although there is some discernible relationship between compliance costs and the target or procurement level, 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.

Going forward, RPS targets will rise, reaching their peak in most states during 2020–2025. These final-year targets, also shown in Figure 3 (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, those rising targets could put upward pressure on RPS compliance costs.



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 preexisting 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).

Fig. 3: Estimated incremental RPS costs compared to recent and future RPS targets

The impact of rising RPS targets on future compliance costs will depend on many factors. First, and perhaps foremost, is the underlying cost of renewable energy technologies. Second is the price of natural gas, because gas-fired electricity is the typical baseline for cost calculations. Third, RPS costs may be affected by changes to government tax incentives that reduce the cost of renewables to utilities. Fourth, environmental policies, such as greenhouse-gas and air-pollution regulations, could raise the cost of non-renewable resources and thus reduce 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 3.4).

Prospective RPS cost studies conducted for individual states or utilities help gauge the potential trajectory of future RPS compliance costs. Chen et al. (4) 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%. However, much has changed on the RPS landscape since that study. More recent analyses have estimated the following rate impacts for final target years: 10% in California (5), 2.2%–4.8% in Connecticut (6), 7.9% in Delaware (7), 1.1%–2.6% in Maine (8), 0.3%–1.7% for Northern States Power in Minnesota (9), 2.2% for Great River Energy in Minnesota (10), and -0.5% (a reduction) in North Carolina (11). 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.

3.4. Cost-Containment Mechanisms

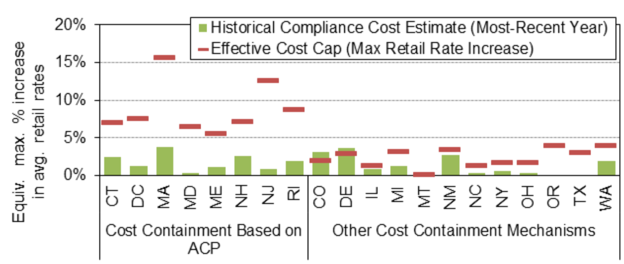
Most RPS policies include one or more cost-containment mechanisms. The most common approaches are ACPs and rate impact/revenue requirement caps:

- **ACPs**. Typical of restructured markets, ACPs can effectively cap REC prices and thus RPS compliance costs.
- **Rate-impact/revenue-requirement caps**. Many regulated states and some restructured states cap RPS costs in terms of a maximum allowed percentage of revenue requirements, costs, or customer bills.
- **Surcharge caps**. Michigan and North Carolina have statutory caps on RPS surcharges (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.
- **Renewable energy funding caps**. Where specific programs are established for the purpose of RPS procurement (e.g., New York), cost containment may occur through limits on program budgets.
- **Financial penalties**. Texas has a pre-specified penalty that can function largely like an ACP in terms of containing 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.

Regulators in many states also 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. In addition, regulators often can review and approve PPAs and/or cost recovery for RPS resources, thus limiting the costs incurred.

Cost-containment mechanisms may sometimes serve as only a "soft" cap. 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. 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.

Figure 4 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. 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 4 also presents actual statewide-average RPS costs for the most recent historical year available.



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.

Fig. 4: RPS cost caps compared to recent historical costs

Among states relying on ACPs for cost containment (at left of figure), RPS costs are generally capped at 6%–9% of average retail rates. The effective caps are higher in Massachusetts (16%) and New Jersey (13%) owing to relatively high solar set-aside targets and/or ACP levels. Recent RPS compliance costs in these states are generally well below the cost caps, 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 real or nominal terms) or, in the case of many states' solar ACPs, will decline over time. 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 4. That might not occur if continued reductions in renewable energy costs and/or increases in wholesale power prices restrain growth in REC prices.

Among states with non-ACP cost containment (at right of figure), cost caps are relatively restrictive, typically the equivalent of 1%–4% of average retail rates. Cost caps have already become binding in several of these states (e.g., New Mexico and Missouri [not shown]). Several other states appear to have surpassed their caps, but for various reasons those caps have not yet been binding (e.g., Colorado, Delaware, and Kansas [not shown]). Other states are approaching their caps (e.g., Illinois, North Carolina, and Ohio). In Oregon, cost caps may become an issue for some utilities, even though historical compliance costs have been low. 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. 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. 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; both utilities project attainment of their RPS targets without any significant increase in surcharges (12, 13).

4. CONCLUSIONS

States have largely complied with RPS targets thus far, and based on our data, they appear to have done so with modest impacts on retail electricity rates. Because of the limitations of the underlying data and methods, however, those findings must be interpreted with caution. For example, the incremental cost estimates for many states omit potentially important costs (such as renewable energy integration costs) and some benefits to customers (such as wholesale electricity market price and natural gas price suppression). These data also neglect broader societal costs and benefits, which may be important for evaluating RPS programs as public policies.

We anticipate that evaluating RPS costs and benefits—and the associated impacts on economic growth—will become even more important as RPS targets rise and cost caps increasingly become binding (potentially curtailing achievement of RPS targets). As our analysis reveals, however, the methods and quality of data available for analyzing RPS costs vary widely. Those data and methods must be improved to meet the emerging analytical demands of utilities and regulators as they assess the costs and benefits of RPS policies.

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