THE PRICE ELASTICITY OF SUPPLY OF RENEWABLE ELECTRICITY GENERATION: EVIDENCE FROM STATE RENEWABLE PORTFOLIO STANDARDS*

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ABSTRACT

Many states have adopted policies aimed at promoting the growth of renewable electricity within their state. The most salient of these policies is a renewable portfolio standard (RPS) which mandates that retail electricity providers purchase a predetermined fraction of their electricity from renewable sources. Renewable portfolio standards are a policy tool likely to persist for many decades due to the long term goals of many state RPSs and the likely creation of a federal RPS alongside any comprehensive climate change bill. However, there is little empirical evidence about the costs of these RPS policies. I take an instrumental variables approach to estimate the long-run price elasticity of supply of renewable generation. To instrument for the price paid to renewable generators I use the phased-in implementation of RPSs over time. Using this IV strategy, my preferred estimate of the supply elasticity is 2.7. This parameter allows me to measure the costs of carbon abatement in the electricity sector and to compare those costs with the costs of a broader based policy. Using my parameter estimates, I find that a policy to reduce the CO_2 emissions in the northeastern US electricity sector by 2.5% using only an RPS would cost at least six times more than the regional cap-and-trade system (Regional Greenhouse Gas Initiative). The marginal cost of CO_2 abatement is $12 using the most optimistic assumptions for an RPS compared to a marginal cost of abatement of $2 in the Regional Greenhouse Gas Initiative.

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1 Introduction

Renewable energy has become a prominent policy issue at both the state and federal levels. Many states have adopted policies aimed at promoting the growth of renewable electricity within their state to decrease carbon dioxide (CO_2) emissions, most prominently through a renewable portfolio standard (RPS). An RPS is a mandate that retail electricity providers purchase a specified fraction of their electricity sales from renewable sources. A typical RPS is passed by a state legislature a few years before the first year retail providers are required to meet the standard to allow new renewable capacity to be built. RPSs usually begin with a requirement that approximately one percent of electricity be produced by renewable sources and incrementally increases over a 15-25 year period. For example, Massachusetts's RPS requires retail providers to demonstrate initially that one percent of their electricity sales come from renewable generation with the amount of required renewable electricity increasing by between one-half and one percentage points in every subsequent year. The end goal for Massachusetts's RPS occurs in 2020, when 15% of electricity sales must come from renewable sources. (See Figure 1 for example timelines.) If a retail provider fails to meet its requirement in a given year, it must pay a penalty proportional to the the difference between the target and the amount of renewable electricity it purchased.

In 1997, three states had renewable portfolio standards (Iowa, Massachusetts, and Nevada) whereas by the end of 2009, 35 states had passed an RPS into law. (Figure 2 displays the number of states adopting RPSs in a given year and Figure 3 displays which states have passed RPSs.) Since the electricity sector accounts for 42% of CO_2 emissions nationally, RPSs may have the ability to substantially decrease CO_2 emissions. However, there has been little quantitative examination of the effectiveness or the cost of CO_2 abatement from RPSs, particularly accounting for heterogeneity in state policies.

This paper estimates the long-run price elasticity of supply of renewable generation capacity by using state RPS implementation schedules as an instrument for changes in the price received by renewable electricity generators. The price elasticity is an important parameter for policy makers since many states have introduced aggressive RPSs to increase the share of renewable electricity sold in their state, but policy makers are unlikely to have empirically based estimates of the cost of these policies.[1] I find that the price elasticity of renewable electricity capacity is approximately 2.7. Using my estimates of the long-run supply price elasticity, I calculate the cost of exclusively using an RPS to decrease the carbon dioxide emissions in the northeastern US. This elasticity suggests that the cost of abating an equivalent amount of CO_2 from an RPS in the northeastern US is between five and fourteen times larger than the costs of CO_2 abatement under a regional cap-and-trade program (the Regional Greenhouse Gas Initiative). I estimate the marginal cost of abatement for a 10% reduction in CO_2 emissions to be between \$50 and \$140 per ton of CO_2 compared with an expected price under \$10 for the cap-and-trade program.

To identify the long-run supply price elasticity of renewable generating capacity, I use variation from the prespecified RPS implementation schedules. The incremental changes in demand for renewable generation from the implementation schedules create an exogenous change in the demand for renewable electricity. These changes provide me with an instrument for the price renewable generators receive for electricity, allowing me to consistently estimate the elasticity of supply.

In order to correctly measure the changes in demand for renewable capacity due to RPSs, I develop a measure of the strength of the incentives created by a particular state's RPS. This measure is different than what has been used in most previous work on RPSs. Menz and Vachon [11] and Adelaja and Hailu [3] use cross-sectional data to examine the effectiveness of RPSs in promoting the development of wind generators.[2] However, both of these papers treat all RPSs the same by estimating the effect of RPSs on new capacity using a simple indicator for a state having

[1] There are some cost estimates of a federal RPS in the literature, for instance see Palmer and Burtraw [15], but these estimates come from simulation models of the electricity sector rather than empirically estimating the response to policies.

[2] There are also a few qualitative assessments of RPS policies. Wiser, Porter and Grace [21] examine many of the policy design issues associated with RPSs and identify broad principles that could be considered best practices. Langniss and Wiser [9] also do a qualitative assessment of the Texas RPS and suggest that it has likely been an effective driver of renewable generation development in Texas.

an RPS. Both papers find that RPSs are correlated with a greater presence of wind generators in that state, but they cannot establish any causal link due to their cross-sectional approaches. In fact, Lyon and Yin [10] suggest that a large wind potential in a state increases the probability of that state passing an RPS, which suggests the causality may go the other direction. Powers and Yin [16] do account for much of the heterogeneity in policies and adopt a measure of the RPS requirement similar to this paper's measure. By using their preferred method of incorporating this heterogeneity, they find a significant impact of RPSs on the share of renewable generation. In another related paper, Kneifel [8] uses panel data on state renewable capacity and attempts to discern which of the variety of renewable electricity policies are most effective at increasing in-state renewable electricity capacity.

The papers mentioned above, with the exception of Powers and Yin, assume that all RPSs create identical incentives for wind generators regardless of how difficult the policies are to meet. This is clearly not a valid assumption, given the heterogeneity in the difference between the state RPS statutory requirements and the amount of new renewable capacity needed to met the RPS. For instance, the first year that Pennsylvania's RPS was implemented, the state had more than enough renewable capacity to meet the requirement; whereas the first year that Delaware's RPS was implemented enough new renewable generation had to be built to power approximately 2% of the state's electricity demand. The difference between the statutory RPS requirement and incentives for new renewable generating capacity can be seen in Figure 1. The light blue bars display the statutory requirement, and the dark red bars show the percent of electricity that must be generated by new sources due to the the RPS.

Importantly, and in contrast to previous work, I aggregate each state RPS to the regional level weighted by the state's consumption, since this is the level at which most RPSs create incentives for wholesale generators. RPSs create incentives for all renewable generators in the region since RPSs can be met with renewable capacity anywhere in the wholesale market. The requirement effectively makes each state's RPS policy an incremental increase in the region's RPS requirements. Without acknowledging that state RPSs are actually regional policies, the previous estimates of the impact of RPSs on renewable generation are biased toward zero since the effective control group in the differences-in-differences estimation is contaminated by neighboring states' policies.

My price elasticity estimates help to inform estimates of the excess burden of CO_2 reductions from RPSs since they are not a first-best policy. In a recent paper, Holland, Hughes, and Knittel [7] show under general conditions that policies that govern the rate of pollution, rather than the level (CO_2 emissions per megawatt hour rather than total CO_2 emissions) cannot be efficient. An efficient (first-best) policy can be described where the price is equal to the marginal cost plus the marginal damages from the externality, as in the case of a Pigouvian tax or a cap-and-trade program.

However, one reason state politicians may prefer an RPS to a cap-and-trade program, even though it is not a first-best policy, is that it is harder for firms to avoid the requirements of an RPS than a cap-and-trade program. RPSs are a regulation that is hard for firms to avoid since they apply to the electricity sold, not produced, in a particular location.[3] There is a large literature examining the extent to which firms avoid environmental regulation by moving production to other jurisdictions, typically called leakage. (See Fowlie [6] for a discussion of these issues.) Since leakage is unlikely to be a problem for an RPS but may be under a cap-and-trade program, my estimates of the excess burden from an RPS can be interpreted as the excess cost to avoid leakage.

The remainder of the paper is organized as follows. In the next section I discuss the details of RPSs, electricity markets, and the dimensions on which there is heterogeneity in RPS policies. In Section 3 I develop a model to ground our thinking about renewable generating capacity investment. In Section 4, I discuss the empirical methodology I use and the key variables. Section 5 describes the data I use to to examine RPSs. Section 6 discusses my results which is followed by a discussion of the policy implications of my estimates in Section 7. Section 8 concludes.

[3]To the extent that renewable electricity increase electricity prices and residents and business locate in a state based on electricity prices, there will be some leakage in these policies. However, for all but the most electricity intensive industries this is likely not to be a problem.

2 RPS Policy Background

Renewable portfolio standards have become increasingly common over the past twenty years. The first law resembling an RPS was passed in Iowa in 1983. The Iowa law required the state's two investor-owned utilities to install a combined 105 MW of new renewable generating capacity. After this law, very little legislation was passed at the state level relating to the fuel mix of electricity generators until 1997 when Massachusetts passed its RPS. This was done as part of the electric utility restructuring legislation whereby electric generating capacity was separated from retail operations of electric utilities.[4]

The RPS requires retail providers to purchase an increasing fraction of their electricity from renewable generators beginning in 2003. After Massachusetts, many other New England and Mid-Atlantic states followed suit.[5] By December 2009, 35 states had passed an RPS. Figures 3 and 2 show the number of states that passed and RPS in a given year and the spatial distribution of when RPSs were passed.

Among the 35 states that have passed RPSs in 2009 some of those states do not have a restructured electricity market. In states that do not have a restructured electricity market, the state public utility commission tends to have substantial influence over the fuel mix of the vertically integrated utilities it regulates since new capacity projects must be approved by the public utility commission and utilities are guaranteed rate of return on their new capacity. This may make a state's RPS superfluous if the state has vertically integrated utilities. This is one reason I will focus only on states that have restructured electricity markets in this paper.

Though all RPSs are passed by state legislatures, nearly every RPS is actually a regional policy since most states simply require that the renewable electricity used to meet the requirement be generated within the wholesale market and wholesale electricity markets contain multiple states.

[4]In a restructured electricity market electricity generators are owned by separate firms from retail providers that sell electricity to end users. This model is in contrast to a vertically integrated utilities that both sell to consumers and produce electricity from generators they own. Section 2.1 will discuss this in more detail.

[5]This was usually done as part of restructuring legislation or shortly afterwards.

Figure 4 shows the New England, PJM and New York wholesale markets.[6,7] Therefore I will aggregate all of the state RPSs in a region into a single regional requirement. I restrict my attention in this paper to states with a restructured electricity market and a transparent RPS compliance mechanism. This restriction allows me to observe the price renewable generators receive for their electricity. The rest of this section will discuss restructured electricity markets and important dimensions of variation and then how RPSs work in practice.

2.1 Restructured Electricity Markets and Renewable Energy Credits

States with restructured electricity markets have three main types of market actors: wholesale electricity generators, retail electricity providers, and end consumers. In restructured electricity markets, firms typically can only be a wholesale generator (and therefore own generating capacity) *or* a retail provider. This is in contrast to the market structure that was common prior to the 1990's where retail electricity providers were vertically integrated with wholesale generators, thus owning generating capacity and selling electricity to consumers.

The restructuring process broke up these vertically integrated firms into retail providers and wholesale generators and created a wholesale electricity market where generators and retail providers submit bids to sell and buy electricity. These markets are operated by a regional independent system operator that makes sure supply and demand in the electricity market balance in real time.

In addition to selling electricity into the wholesale market, generators that use renewable sources also create a renewable energy credit with every megawatt hour (MWh) of electricity produced. Renewable energy credits (RECs) are a pure financial product (in most markets) that retail

[6] The only states that require the renewable generation be located in the state are states that are a wholesale electricity market unto themselves, including Texas, California, New York, and Hawaii. Texas and Hawaii have their own electricity grids, while New York and California have their own Independent System Operators, thus making the state the natural unit of observation.

[7] The regions I will examine in this paper are the New England ISO, comprised of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont; the PJM control region, which includes Delaware, Maryland, New Jersey, Pennsylvania, Virginia, West Virginia, and parts of Illinois, Indiana, Michigan, and Ohio; and the Electric Reliability Council of Texas (ERCOT).

electricity providers are required to purchase to show compliance with a state's renewable portfolio standard.[8] Typically a REC describes the attributes of the electricity that was produced such as the location of the generator, the fuel that was used, and the date that the electricity was produced. Using this information, retail providers can purchase RECs that qualify to meet a particular state's RPS. At the end of the year, retail providers retire the RECs that they have purchased to meet the RPS to the state regulator.

In order to ensure that retail providers comply with RPS requirements, nearly all states have set up a system of fines for retail providers that are short of their required number of RECs. These fines, generally called alternative compliance payments, effectively set a price ceiling in the market for RECs. If a retail provider has not purchased their required number of RECs, the alternative compliance payment specifies a dollar amount per megawatt hour that the retail provider must pay to the state. The level of the alternative compliance payment is usually determined by the state's public utility commission and is generally above the market price for RECs, giving retail providers an incentive to purchase RECs instead. Some states explicitly link the alternative compliance payment to a multiple of the market REC price, while others such as Massachusetts re-evaluate the penalty every few years to make sure the price is still above the market price for RECs. In many states, retail providers end up paying relatively few fines. For instance, in 2003, Massachusetts collected less than 1% of the RPS requirements through alternative compliance payments.

These RECs provide a second stream of revenue for renewable generators. Since the average cost of renewable generation tends to be higher than that of fossil generation, the revenue from selling RECs encourages new renewable generating capacity to be built. The total price renewable generators receive for each MWh of electricity is the price of the electricity plus the price of the REC.

[8]California requires retail providers to enter into long term contracts with renewable electricity producers to purchase both the electricity and RECs to fulfill the state's RPS obligation. This requirement was lifted by the California Public Utility Commission in March 2010. California retail providers may purchase unbundled RECs to fulfill the RPS requirement in a limited amount in 2010 and 2011, with the market becoming completely unrestricted in 2012.

2.2 Variation in State RPSs

Most states' RPSs have a final goal for their RPS by 2020 or 2025, usually between 10 and 30 percent of electricity sales, but the RPS is phased in over time. For instance, Massachusetts' end goal is for 15% of electricity sales to come from renewable sources by 2020, but interim requirements begin in 2003 at 1% of sales and increase by 0.5% or 1% every year until 2020. Other states have more aggressive schedules by increasing their renewable requirement by a larger amount every year while other states have large jumps in their requirements, such as California which has a requirement of 20 percent in 2019, and 33 percent in 2020. The light bars in Figure 1 shows a representative sample of RPS implementation schedules. These implementation schedules provide the variation across time that will allow estimation of the supply elasticity.

Another important dimension along which state polices differ is the treatment of how retail providers are required to comply with the policy mandate. In nearly all states, all retail electricity providers comply with an RPS policy by retiring renewable energy certificates (RECs). Some states require that the renewable electricity used to meet the RPS be produced within the state,[9] while most other states just require that the generator that produced the electricity be part of the regional transmission organization so that, in theory, the electrons from the renewable electricity were in the same system. These geographic requirements attempt to get around the problem of creating a simple reshuffling of electricity purchases. [10]

[9]The states that require RPS generation to be within their borders are Hawaii, Iowa, North Carolina, New York, and Texas.

[10]Bushnell, Peterman, and Wolfram [5] show that local, consumer-based policies can be circumvented by a simple reshuffling of buying/selling pairs. For instance, consider an example where there are just two states with a common wholesale electricity market: state A has passed a 10% RPS and state B does not have an RPS. Moreover, assume that state B has enough renewable capacity to meet state A's RPS requirement, while state A does not have any renewable generating capacity. Before the RPS was enacted in state A, both states' retail electricity providers purchased all of their electricity from within their respective states. (Since there is a common wholesale electricity market, the electricity prices are equalized across states.) However, after the RPS is enacted, the retail electricity providers in state A switch to purchasing electricity from the renewable generators in state B and retail providers in state B switch to purchasing electricity from non-renewable generators in state A. Thus, state A's RPS has only resulted in reshuffling the buying/selling pairs and failed to increase the fraction of renewable generating capacity as a whole. As this example illustrates, this may be a major drawback of state level policies such as RPSs that interact with a interstate market. However, geographic requirements restrict the amount of reshuffling that is possible under an RPS.

State RPSs also vary as to which fuels that each state considers eligible to meet the RPS. While they generally include generation from sources such as wind turbines, solar (both photovoltaic cells and solar thermal sources), biomass (such as wood or wood waste), landfill gas, and small hydroelectric generation, some states also consider fuels such as municipal solid waste as renewable. In order to encourage specific types of fuels or to encourage a larger set of fuels, some states have created multi-tiered RPSs. Table 1 shows the fraction of states with an RPS that include each fuel type in the first tier of its RPS, the average carbon emissions per unit of heat input from using that fuel, and the average size of generators for each fuel. I will focus only on the first tier of each state's RPS since they provide stronger incentives to renewable generators (through higher prices for the RECs).

Each state must decide how to treat the renewable electricity generating capacity that exists when the RPS law is passed. Many states allow all existing renewable capacity for wind and solar generators to produce RECs that qualify to meet the state's RPS, but treat generators that use other fuels such as landfill gas, municipal solid waste, and especially hydroelectric facilities differently depending on when they were built and/or last modified in a substantive way. Most states consider hydropower installations that are smaller than 30 MW to qualify for the RPS. However, sometimes incremental additions to larger installations will not qualify for the RPS. Also, some states allow existing generators to meet only a fraction of the RPS requirement while new generators must meet the rest.

I have incorporated all of these important dimensions of heterogeneity into my empirical work and ensured that all of the facilities in my data that are eligible to meet an RPS requirement are actually eligible under the RPS rules of at least one state in the region. The next section will introduce a basic model of investment electricity generating capacity which will guide my empirical work.

3 Model

In this section I develop a model of investment in electricity generating capacity to illustrate the effect an RPS has on the incentives of electricity producers. The model provides the basic intuition of how policy can affect generating capacity decisions and motivates my empirical specifications.

Consider a representative firm deciding whether to invest in new generating capacity. For the power plant to be profitable, the revenue the generator produces over its lifetime must exceed its capital and operating costs:

$$\sum_{t=0}^{T} \beta^t \, \mathbb{E}[p_t q_t] \geq K_0 + \sum_{t=0}^{T} \beta^t \big(m_t + \mathbb{E}[f_t q_t] \big) \tag{1}$$

where p_t is the price of electricity at time t, q_t is the quantity of electricity the generator provides at time t, K_0 is the initial capital cost of the generator, m_t is the variable operating and maintenance costs associated with the generator at time t, f_t, is the fuel cost at time t, T is the number of years of the useful life of the new capacity, and β is a discount factor.[11] In equilibrium this condition holds with equality. This equilibrium is graphically depicted in Figure 6, with the long-run supply curve for renewable generation (right axis) separated from the long-run supply curve for fossil generation (left axis). When demand is perfectly inelastic I can show these supply curves on the same figure with the length of the horizontal axis showing the total quantity of electricity demanded (inelastically).[12] The vertical line shows the fraction of demand that is met with fossil generating capacity versus renewable generating capacity. Since retail providers have no preference over the fuel used for electricity, the equilibrium fraction must be at a point where the price is equalized across types of generators.

[11] This profitability condition abstracts away from any payments that generators receive for participating in ancillary service markets where generators may be paid to be on standby, ready to produce electricity if called upon by the market operator. Typically renewable generators are not eligible to participate in these markets due to the unpredictability of wind and solar generation. However, an increase in the amount of wind and solar generators participating in the electricity market will cause an increase in demand for standby capacity services from fossil generators.

[12] This assumption is for convenience in the depiction of the wholesale market. The model does not need this assumption and is relaxed in the empirical work in the rest of the paper.

A new generator will enter the market when there is sufficient excess quantity demanded over the life of the generator such that inequality 3 holds. (This is depicted graphically by lengthening the horizontal axis, necessarily increasing the market clearing price.) Two ways to induce generators to enter the market are to decrease the cost of the capital investment or to increase the price the generator will receive for its electricity over the new capacity's life span. These two levers have been used by the federal government to induce more renewable generators to enter the market in the form of the Investment Tax Credit and the Production Tax Credit, respectively.

Renewable portfolio standards also induce renewable generators to enter the market by shifting the fraction of demand that is met with renewable sources to the left within the figure. This is not a change in the total electricity demand but a change in the composition of production. This change causes a wedge in the price for electricity since renewable generators must receive a higher price for their electricity to build capacity. The price wedge resulting from the RPS is shown in Figure 7. The price renewable generators need to receive for their electricity to enter the market is p^r, but the equilibrium price given the number of generators in the market is p^e, so the difference is made up by the price of the REC:

$$p^{REC} = p^r - p^e \tag{2}$$

Expanding equation 2 to show the total electricity price, the profitability condition in equation 3 becomes:

$$\sum_{t=0}^{T} \beta^t \, \mathbb{E}[(p_t^e + p_t^{REC})q_t] \geq K_0 + \sum_{t=0}^{T} \beta^t \big(m_t + \mathbb{E}[f_t q_t]\big) \tag{3}$$

for renewable generators. Renewable generators consider the price path of both the price of electricity and the price of RECs when considering entry decisions. So long as the price of RECs is expected to be greater than zero, renewable generators have an additional incentive to enter the market. Notice also that entry decisions depend on the flow of revenue to the generator over the life of the generator, not just the contemporaneous revenue.

The profitability condition implies that each generator has a critical (total) price at which it will enter the market. Therefore, as contemporaneous prices and expectations about future prices change we see generators entering the market consistent with the profitability condition.

We can derive a supply curve for renewable generators by aggregating each firm's decision about whether to enter the market. Each generator enters the market if their profitability condition holds. Thus, the total new generating capacity in the market at time t is:

$$Q_t = \sum_i \mathbb{I}\Big[\sum_{t=0}^{T} \beta^t\,\mathbb{E}[(p_t^e + p_t^{REC})q_t] \geq K_i + \sum_{t=0}^{T} \beta^t \big(\,\mathbb{E}[m_{it} + f_t q_{it}]\big)\Big] \tag{4}$$

where i indexes generators.[13] Notice that there is a generator-specific capital cost, and each generator can expect a different amount of output. These two terms rationalize why we observe some renewable generators in existence in areas without a binding RPS. Consider a wind developer looking at potential locations to install a wind turbine. Not all locations are of equal value to the developer due to the fact that the wind blows at different speeds and different times at each location. Sites where the wind blows more frequently, all else equal, will be worth more to the developer since the turbine will create more electricity and has a marginal cost near zero. Thus, the best locations will be developed first with each subsequent wind turbine being placed in marginally inferior location, necessitating a marginally higher price for the electricity generated by that turbine to make it profitable. This suggests that existing renewable capacity satisfies the profitability condition in equation 3, but that as demand for renewable capacity increases, renewable generators will need to receive a higher price for their electricity. Thus, the upward slope of the supply curve is driven by heterogeneity in the value of locations and capital costs.

In order to aggregate across generators, I need to make several assumptions. The main as-

[13]Note that the same condition holds for fossil generators, except their expectations over the price of RECs do not enter their profitability condition.

sumption in the aggregation is that all generators have the same expectations over the trajectory of prices (electricity and RECs) over the life of each generator. With this assumption, I can rewrite the equation 4 as

$$Q_t = f(p_t^e, p_{t+1}^e, ..., p_{t+T}^e, p_t^{REC}, p_{t+1}^{REC}, ..., p_{t+T}^{REC}) + \delta X_t \tag{5}$$

where X_t is a set of variables capturing the other factors that effect a generator's entry decisions such as fuel costs.

This equation suggests that I can estimate the price elasticity of supply of renewable generation using the familiar log-log specification by regressing the log of quantity of new renewable capacity on the log of price and other factors that affect entry decisions. However, this presents the traditional problem of simultaneous equations bias since price and quantity are determined by the intersection of supply and demand. Since, price is an endogenous regressor, I need an instrument for the price that renewable generators receive to consistently estimate this equation.

4 Empirical Strategy

In order to estimate the long-run price elasticity of supply of renewable capacity, I use the implementation schedules of state RPSs as an instrument for the price that renewable generators receive for their electricity and then use the predicted change in price in a second-stage regression to estimate the price elasticity of renewable generation. RPS implementation schedules provide me with an exogenous change in the demand for renewable generating capacity that can instrument for the changes in price that renewable generators receive. RPS implementation schedules are typically written into the original RPS legislation and increase the RPS requirement each year that the RPS is in effect until the end goal is met. Because these schedules are incremental changes in demand that are not determined at the same time as the price, and therefore are not correlated with unobserved supply shocks, they are a good instrument for the total price that renewable electricity generators receive for their electricity.

This leads to a way to estimate the the long-run price elasticity of supply for the renewable generators. Each new RPS requirement increases the demand for RECs, increasing the wedge between the price that renewable and fossil generators receive for electricity. Importantly, the change in demand that I observe in the REC market comes from the RPS legislation, making the variation more plausibly exogenous. Thus, I can separate the change in total electricity price renewable electricity generators receive due to the RPS from other market forces to trace out the supply curve of renewable generating capacity and estimate the price elasticity of supply.

4.1 Estimating Equations

My model suggests two natural estimating equations to estimate the long-run price elasticity of supply. The first-stage equation estimates the price response to an exogenous change in the demand for RECs. The demand for RECs change in a predictable way due to the implementation schedule of each state's RPS. As derived in section 3, new renewable generating capacity should respond to the entire flow of payments over the life of the generator. To capture this variation I use a measure of changes in RPSs' stringency averaged over the next five years.[14] This leads to a first stage equation of the following form:

$$log(p_{it}^{total}) \quad = \quad \beta log(RPS\ Requirement_{it,t+5\ years}) + \delta X_{it} + \alpha_i + \gamma_t + \epsilon_{it} \tag{6}$$

where the α_i's are region fixed effects, the γ_t's are year and month fixed effects, and X_{it}'s are a set of controls for other policy variables that may effect the incentives of renewable generators. The region level fixed effects absorb time invariant differences across regions such as differential

[14] I wil discuss how this variable is constructued in Section 4.3. The results are not sensitive to the choice of a five year average. The results are similar for averages up to 10 years of the RPS requirement, though are noisier the longer the time period that is averaged.

renewable generating potential, as Lyon and Yin [10] suggest may be important in the decision to adopt an RPS. The year and month fixed effects absorb differences across time that are constant across region. These are important since over our period of examination various federal tax incentives have taken effect (and occasionally not been renewed immediately) such as the Investment Tax Credit and the Production Tax credit that affect the financial desirability of building renewable generation. For a discussion of the history of these policies and their consequences see Metcalf [12], Wiser et al. [19], and the Joint Committee on Taxation [2]. I also include a group of other policy variables in both estimating equations, X_{it}, to control for other policies that affect the incentives for renewable electricity providers unrelated to RPSs. These variables allow for a more isolated estimate of the effect of *only* the RPS.[15]

As discussed in Section 3, generators should be making entry decisions based on the time path of prices, not just contemporaneous prices. However, most RPSs allow a RECs that were created and/or purchased in one year to be turned in for compliance in the following two years. Therefore the contemporaneous REC price contains information about the price of RECs in the future we should observe generators responding to the contemporaneous price since it is also a signal about future prices.

The second stage equation that will give us an estimate of the price elasticity of supply takes the following form:

$$log(RenewableCap_{it}) = \beta \widehat{log(p_{it}^{total})} + \delta X_{it} + \alpha_i + \gamma_t + \epsilon_{it} \quad (7)$$

where the α_i's are region fixed effects, the γ_t's are year and month fixed effects, and X_{it}'s are a set of controls for other policy variables as in the first stage.

[15]These other policy variables are discussed in detail in Section 5.4.

4.2 Which States get RPSs?

In order for the instrument of RPS stringency to be valid, it must not enter the supply equation except by entering through the demand equation. The implementation schedule may indeed enter the supply equation if, for instance, states that have more renewable generating potential choose to adopt RPSs. This would cause me to overestimate the effects of RPSs since those states are also likely to develop more renewable generation capacity than other states even in the absence of an RPS.

Upon casual observation of the dates at which various states adopted their RPS policies, this doesn't seem to be a particularly large problem. (See Figure 3 for a description of when each state passed their RPS.) Some of the states with the largest renewable potential from both wind and solar are in the Plains states and the Southwest. While many of the states in the Southwest do indeed have RPSs they are not uniformly early policy adopters. Conversely, most of New England and the North Atlantic states have adopted RPS policies, some being among the first adopters but do not have a large renewable generating potential.

Moreover, many of the first adopters of RPS policies adopted their RPS as part of the electricity restructuring legislation. The electricity restructuring legislation in many of these states was a major piece of legislation that separated the retail and wholesale electricity markets, making the latter market a "deregulated" market, usually with plans to make the retail electricity market a competitive, unregulated market in the future. Most of the deregulation of the electricity markets were motivated by high retail electricity prices in the state and generally a group of states in a region deregulated the wholesale electricity market at similar times. There is very little reason to believe that the deregulation legislation is correlated with unobserved covariates that affect renewable electricity capacity.

Lyon and Yin [10] empirically examine which states get RPSs. Their findings suggest that wind potential in the state increases the probability of RPS adoption (though not potential in other fuels that are typically included in RPSs such as solar or biomass). This will not be a problem for me since I will be controlling for this variation through my region level fixed effects.

Lyon and Yin also find that high local pollution levels, as measured by the fraction of the population living in counties that are designated as “nonattainment” under the Clean Air Act, increase the probability of adoption of an RPS as well as some evidence that organized renewable energy lobbying groups increase the probability of adoption. In contrast to Rabe’s [17], [18] qualitative examination, they also find that a state’s unemployment rate decreases the likelihood that a state will adopt an RPS. Rabe [18] finds that states often emphasize the potential economic benefits of RPSs such as creating “green” jobs or gaining a competitive advantage as a first mover in renewable energy technology, but this does not seem to be a driving factor empirically as measured by the unemployment rate. These papers give me confidence that RPS adoption is likely to be uncorrelated with many of the unobservables that would invalidate the instrument. Moreover, since RPS policies affect neighboring states as well as the states in which they are passed, they are even less likely to be correlated with in-region unobservables.

Since my instrument for changes in demand for renewable capacity is not just the beginning of an RPS in the region, but also the implementation schedule that each RPS follows, the implementation schedule must be uncorrelated with in-region unobservable characteristics. Two main concerns come to mind when considering the exogeneity of the RPS implementation schedules. First, states that are early adopters of RPSs may have particularly aggressive implementation schedules, either due to a strong desire to promote renewable electricity generation or because they have a lot of renewable resources that can be exploited.

A second concern about the exogeneity of RPS implementation schedules is that states that have a lot of renewable generating capacity at the time the RPS is passed will have more aggressive implementation schedules. Since more aggressive implementation schedules likely lead to higher REC prices sooner, existing renewable generators clearly have a lot to gain by lobbying state legislatures for more stringent requirements.

Both of these concerns can be addressed empirically by examining the state implementation schedules. Since most RPSs follow a nearly linear implementation schedule, I estimate the slope of the implementation schedule by regressing each schedule on a time trend. I then examine the correlation between these slopes and variables that address the concerns raised above about the endogeneity of implementation schedules.

To address the first concern that early adopter states have more aggressive implementation schedules, I regress the slope of the implementation schedule requirements (in MW of required new capacity) on the year that each state's RPS went into effect. The coefficient on the year the RPS went into effect is not statistically different from zero with a coefficient of -7.7 and a standard error of 17.7. The point estimate suggests that early adopters require an extra 8 MW of renewable capacity each year of an RPS but is clearly not statistically different from zero ($p = 0.67$). Moreover, an additional requirement of 8 MW per year is a relatively small difference given that the average increase in RPS requirements is 166 MW per year.

To address the second concern that states with a larger renewable sector before RPS passage will have a more aggressive implementation schedule, I regress the slope of the implementation schedule on the renewable capacity in that state at the time of RPS passage. The coefficient is not statistically different from zero with a coefficient of 0.18 and a standard error of 0.11. This suggests that the implementation schedules are not a function of the renewable interests already established in a particular state.

This may be because many states choose "round" numbers for both their end goal, such as "20% renewable electricity by 2020," and a linear implementation schedule. Likely, these end goals are less amenable to manipulation by pressure groups and since the intervening years' requirements are essentially a linear interpolation back through time, the implementation schedule is not changed much by pressure groups.

Another concern about my approach is that the RPS policies may spill over into other regions that do not have RPSs or less stringent RPSs. However, there are likely only very small spillover effects in my setup since the unit of observation is a regional electricity market. Many states publish a list of all of the approved generation facilities that are eligible to produce RECs that meet the state RPS. While occasionally there are power generators located in states not included in the wholesale power market, a vast majority of the approved generation facilities are indeed located in states in the wholesale power market.

4.3 Key Variables

The primary variable of interest in the first stage regression is a variable constructed to measure the stringency of a particular state's RPS. Most states, with the exception of Iowa and Texas, set their RPS goals out as a percentage of electricity sales, measured in megawatt hours (MWh). For instance, Michigan's RPS, passed in 2008 calls for 10% of each retail provider's electricity sales to come from renewable sources by the end of 2015 with a phase-in period beginning in 2012. The first challenge we face is converting an RPS goal stated in MWh[16] to our capacity data in MW. One megawatt hour of electricity is created simply by a 1 MW facility producing at full capacity for one hour. This means, in theory any facility's nameplate capacity (in MW) can be converted into a yearly capacity in MWh by multiplying the nameplate capacity by $8760 (= 24 \times 365)$ hours.

However, generators do not run the entire year since they must be shut down for maintenance and may choose not to operate for any number of reasons, including bidding in a price that is higher than the market clearing price in a particular hour. Plants that are almost always producing are usually large coal and nuclear plants that operate between 85%-90% of the time (capacity factor of 85%-90%). Other plants are built to only operate a small fraction (as little as 1% or less) of the time, when the demand (and hence price) for electricity is at its peak. These generators tend to use natural gas since they can bring themselves up to full capacity quickly. Wind generators typically have a capacity factor near 35% [23] since wind is an intermittent resource. For the purposes of

[16] RPS goals are usually stated as a fraction of electricity sales, measured in MWh. Thus, it is simple to convert percentage goals into MWh.

our main analysis, we assume that all new plants have a capacity factor of 40% since most of the needed capacity to meet RPSs is expected to be wind but some of it will be met with fuels that can have a significantly higher capacity factor [20].[17]

In order to correctly measure the incentives of these policies I first need to construct a variable to measure the eligible megawatt hours of renewable generation for state i at time t.

$$\text{RPSCapMWh}_{it} = \sum_{f \in F} \text{RPSCapMW}_{itf} \times 8760 \times \text{AvgCF}_f \tag{8}$$

where f is a particular fuel and F is the set of all eligible fuels. RPSCapMW_{itf} is the sum of nameplate capacities of all generators in state i at time t for fuel f, and AvgCF_f is the average capacity factor for fuel f.[18] I set AvgCF, the average potential capacity factor for a particular fuel, equal to 0.4 for wind and solar generators and 0.8 for all other generators.

Returning to the Michigan example, in order to figure out how hard this goal is to reach, we must consider how much eligible renewable capacity already exists in Michigan to meet the RPS. Some states have RPS implementation schedules such that during the first few years of the RPS, the whole requirement can be met with existing generating capacity.[19] As mentioned above, each state treats existing capacity differently. Since MI allows existing renewable capacity to be eligible to meet the RPS, to compute the incentives created by the RPS, I subtract the eligible capacity at the time the RPS was passed from each year's RPS requirement.

Using the amount of renewable generating capacity at the time the RPS was passed, I calculate

[17]Figure 5 shows that it is indeed the case that most of the change in generating capacity over the last few years has been in wind capacity.

[18]Capacity factor is the fraction of hours in a year that a generator is producing electricity.

[19]This means it is possible for an RPS to create zero incentive in some or all years. For instance, Maine passed an RPS in September 1999 that had a final goal that was less than the existing eligible capacity within the state. Subsequently, in 2006 Maine passed another RPS that only new renewable facilities were eligible to meet the requirement. This is the RPS we consider for Maine in this paper.

the RPS stringency measure in megawatts as,

$$\text{Adjusted Requirement}_{it} = \frac{\text{Requirement}_{it} \times \text{ConsumptionMWh}_{it} - \text{RPSCapMWh}_{i0}}{8760} \times \frac{1}{\text{AvgCF}} \quad (9)$$

This adjusted requirement measure will be our key independent variable as it capture much of the heterogeneity across state policies and I expect the coefficient on it to be positive and significant.

After computing these variables on the state level, they are aggregated up to the regional level by weighting them by each state's electricity consumption share in the region.[20] Moreover, since I am using price data in the second stage, I need to limit my sample to regions that have a robust wholesale electricity market and REC market. Thus, I will be focusing on three regions of the country: New England, the Mid-Atlantic states in PJM, and Texas.[21]

The final I need to construct is the complete price that renewable generators receive for the electricity they produce. As mentioned above, there are two revenue streams for renewable generators under an RPS: the revenue from each megawatt hour of electricity they sell into the electricity market and the revenue they receive from each REC associated with each megawatt hour of electricity that retail providers retire at the end of each year to comply with the RPS. This means that the complete price for renewable generators is

$$p_t^{total} = p_t^{electricity} + p_t^{REC}. \quad (10)$$

[20]The weights are computed using a state's consumption share in 2003 to keep them across time. Changing the weights to the contemporaneous consumption share in each region does not change the results.

[21]I exclude California from the analysis because until recently, there was not a market for RECs since the California Public Utility Commission required retail providers to purchase both renewable electricity and its attributes (essentially RECs) together via bilateral (private) contracts. Therefore, there is not a market price for RECs to use in the second stage. I exclude Midwest states since there is not a developed market for RECs. I also exclude New York since the New York State Energy Research and Development Authority (NYSERDA) centrally procures the RECs for the entire state's commitment through an annual bidding process. It is not clear that this processes elicits the same price due to possible market power on behalf of the NYSERDA.

5 Data

To estimate the empirical models, I use data on all existing electricity generators and production from the Energy Information Administration (EIA). I collect data on REC prices from public utility commission reports and electricity price data from independent system operators of wholesale electricity markets. Data on central policy variables are aggregated from the North Carolina State University's Database of State Incentives for Renewables & Efficiency.

5.1 Generation Capacity Data

The Energy Information Administration annually surveys all electricity generators to collect basic data for each electric generating unit in the United States. All generators that have a potential capacity of at least 1 megawatt, are connected to the electric power grid, and are able to deliver power are required to fill out form EIA-860. The data files include information about each generator including its capacity, all fuels used during that year, the year and month the generator began operation, the year and month of retirement, the city and state that the plant is located in, and basic information about the owner.

Though these data are reported annually to the EIA, they can be translated into monthly data on total generating capacity since the data report the first month of operation for each plant. I use the data reported in these surveys from 1999-2007.

In these data, each generator provides detailed data on the type of fuel used during that year for electricity generation, including up to six or more fuels that were used. I consider the first fuel listed as the generator's primary fuel.[22] For the purposes of this paper, I aggregate these fuels into 17 categories. Most of the fuels that are lumped into the same category are different types of coal, petroleum products, and various waste products. None of these fuels are considered to be

[22]Only one-third of plants report using two fuels, and less than 5 percent report using more than two fuels. Of the plants that list using two fuels, only 6 percent of generators that are categorized as using a renewable fuel list a non-renewable fuel as their second fuel, concentrated among generators that are categorized as biomass, landfill gas, and municipal solid waste.

renewable in any of the RPSs and therefore this aggregation should not affect the results.

5.2 Electricity Sales and Production Data

In order to translate a RPS requirement that is usually in terms of percent of sales of electricity and to create each state's weight in the region I use data from the Energy Information Administration's state historical tables on electricity sales. These data report the total megawatt hours sold in the entire electric industry for a given state in a given year. I also use data on electricity generation aggregated to the state$\times$year level by the EIA. These aggregate data are based on another survey the EIA conducts, EIA-906.

5.3 Price Data

Data on the wholesale price of electricity were collected from each Independent System Operator's (ISO) web site. ISOs publish data on the market clearing price of electricity for many locations in each region for every hour of the day. Where available, I use the published regional weighted average price for each hour and then average the price over each calendar month. Some ISOs do not publish a regional electricity price, instead only publishing data for each location in the ISO. Where this is the case, I take a simple arithmetic mean of the prices across all locations to form an hourly regional price and then average this mean over the entire calendar month.

In order to compute the complete price that renewable electricity generators receive for their electricity, I need to add the price of renewable energy credits (RECs) to the price of the electricity. I have collected average annual prices for RECs in every state that allows RECs to be purchased separately from electricity. These prices are gathered from public utility commission documents or other agencies administering a state's RPS.

The raw price data for REC prices can be seen in Figure 8. The state REC prices exhibit distinctly regional variation confirming that the market for RECs is indeed regional. Much of the within-region variation is due to some temporary state-level policy uncertainty and small variations in eligible fuels, as well as small variations in which generators are certified in which state.

5.4 Policy Variables

The policy variables are constructed from information compiled at North Carolina State's Database of State Incentives for Renewables & Efficiency (DSIRE). DSIRE has cataloged all state incentives for renewable energy including the date they were enacted, when and if they were modified, as well as many details about each policy. Where necessary, this information was supplemented by consulting the actual state statutes.

The variables that were constructed include the date that a particular renewable energy policy was passed by the legislature, when the policy began to bind (if different), and the implementation schedules for RPSs. In addition, information for each RPS regarding what fuels are eligible to meet the requirements, and in some cases maximum capacities for eligible facilities, were taken from this database.

In addition to collecting data on state RPSs from DSIRE, I collect data about other policies that have been implemented in some states that could change the incentives for renewable electricity generators. These policies include:

- **Net metering**: This type of legislation requires that electricity meters "run backward." If a customer has installed generation equipment on site (usually a photovoltaic solar panel) that produces more electricity than a customer is currently consuming, the excess electricity is fed back onto the grid and the customer's electricity bill is credited the retail electricity rate for each kilowatt hour. (See Borenstein [4] for an analysis of these policies.) This net metering may provide an additional incentive for electricity customers to invest in their own generating capacity and then sell the RECs from this generation.
- **Public Benefits Fund**: In many states with competitive wholesale electricity markets, re-

tail electricity providers are required to levy a surcharge on all rate payers to remit to the state government. This money is often used for energy efficiency programs, to help finance renewable energy projects including transmission and distribution projects, and to assist low-income rate payers. Since these funds partly subsidize renewable generation, they are controlled for in the regressions.

- **Government Purchases of Green Electricity**: Some state governments have committed themselves to purchasing a share of their electricity from renewable sources. Since governments are large customers, this may (and is presumably hoped to) affect the amount of renewable capacity. Though both government purchases of green electricity and RPSs require retail providers to retire RECs in the amount of the green purchases, the RECs retired are not counted toward a retail provider's RPS requirement.
- **Mandatory Green Power Option**: Some states have passed legislation that requires retail electricity providers to offer their customers an option to purchase green electricity. Retail providers are allowed to charge extra for providing this electricity. These customer purchases generally are explicitly forbidden from counting toward the RPS requirement. These policies may, however, increase renewable capacity if a sufficient number of customers sign up for these programs.

Table 2 displays summary statistics for the policy variables listed above. The top panel displays summary statistics after aggregating state policies to the region level, and the bottom panel displays the RPS requirements during my sample period for individual states. These bottom statistics correspond to the values of the light blue bars in Figure 1.

Just over half of the region-months in my sample have an active RPS in the region, with a mean renewable requirement of 0.6% renewable generation and a maximum of 2.5%. The mean RPS requirement, conditional on an RPS being enforced, is just over 1% of electricity consumption coming from renewable generation. Taking a look at the state-level data, I observe just 20% of state-months in our sample with an active RPS, with an average requirement of 1.7% renewable generation, conditional on an operational RPS.

5.5 Data Restrictions

As discussed before, there are many dimensions of heterogeneity across state RPSs. In order to simplify my analysis, I will only consider the first tier of each state's RPS. Typically, if a state has multiple tiers to its RPS, the second, third, and fourth tiers allow a greater degree of flexibility for fuels that have higher carbon emissions per unit of heat input. Tiers two and below tend to include fuels such as municipal solid waste or large, existing hydroelectric facilities. (Some states with a single tiered RPS include these fuel types in the RPS.)

If a particular fuel counts for both tier one and tier two in a state, I attribute all of the capacity from facilities using that fuel to fulfilling the first tier of the RPS. Compliance RECs for the first tier are uniformly more expensive than compliance RECs for other tiers (with the exception of states with a solar photovoltaic tier), so this assumption is likely consistent with firm incentives [22]. To the extent that not considering these other tiers of RPSs biases my results, the results should bias the elasticity toward zero. This is because I may be excluding some renewable facilities that may have been built in response to an RPS.

I also do not examine the solar photovoltaic (PV) tiers of state RPSs. Usually if a state has a specific tier for PV, it is the only fuel in that tier. These tiers usually have small requirements, since PV is an expensive way to produce electricity. Moreover, most PV installations are excluded from my data since only generators over 1 megawatt are required to report to the EIA. PV installations tend to be less than 0.1 megawatts, since many of these installations are on the roofs of residential or commercial buildings.

5.6 Aggregation

Aggregating state policies to a regional policy is relatively straightforward. Each state's RPS requirement is weighted by the fraction of electricity consumption that the state accounts for in the region. Thus, if a region consists of three states, state A consumes 50% of the electricity in the region and states B and C each consume 25% of regional electricity. If state A passes an RPS that requires 2% of the electricity sold in that state, the region then is assigned an RPS requirement of 1% (= 2%×50%). In the following year, state A's requirement increases to 3% and state B introduces a 1% requirement so the region's RPS requirement is then 1.75% (= 3%×50% + 1%×25%).

The other state level policy variables (public benefits funds, green power options, etc.) are aggregated in a similar fashion to this, except each variable is simply an indicator for each state, so the variables take on the cumulative fraction of electricity consumption in the region covered by those policies.[23]

6 Results

The results from the first stage regression are displayed in Table 3. Column 1 begins by simply regressing the logarithm of the total price for renewable electricity (electricity price + REC price) on the logarithm of the average effective RPS requirement for renewable capacity in that region over the following five years.[24] As mentioned above, the average requirement is used since it is correlated with future stream of payments over the lifetime of the generator.

We see that the measure of the stringency of an RPS is statistically and economically significant. Column 2 allows each type of control policy to have a one-off effect in the region once any

[23] For simplicity, the weights used are calculated as the state's fraction of consumption in the region during 2003. This keeps the policy and RPS variables weakly monotonic across time. It is unlikely that generators can accurately predict the small variations in electricity consumption across regions for them to take these fluctuations into account. Changing the year used for the weights or using contemporaneous weights do not change the results.

[24] All specifications are robust to the number of years over which the effective requirement variable is averaged.

state adopts it. Column 3 instead adds control variables that can take values between zero and one depending on the fraction of electricity consumption in the region that is covered by one of the policies. Column 4 allows for both a one-off effect in the region and an increasing effect over time as more states in the region adopt these policies. This flexible specification makes sense intuitively, since I would expect that the more expansive these policies are, the larger in magnitude the effect should be. The point estimates for the excluded instrument, the average stringency of the RPS over the next five years, are relatively stable across columns.

Examining the other coefficients in Column 4, the coefficients match my intuition about the direction of the effect. I expect a positive effect on REC prices from government purchases of green power since this increases the demand for green power without decreasing the demand for RECs. Most states do not allow green power purchased through government purchases, to count toward retail providers' REC fulfillment obligations; instead these purchases simply add buyers into the green electricity / REC market. I also see that public benefits funds tend to reduce the price of RECs. Again, this matches our intuition since often the money collected in public benefits funds is used to subsidize the construction of renewable generating facilities, thus reducing the price needed to make the facilities profitable.

The last row of each column shows the F-statistic of a test that the excluded instrument in the regression is zero. All four columns reject the null that both coefficients are zero at all usual levels of confidence. This gives confidence moving forward that the instruments are indeed relevant.

All standard errors in this table and the second stage regressions are estimated using Newey-West heteroskedasticity and auto-correlation robust standard errors. The number of lags included in the auto-correlation estimation was chosen using the procedure suggested by Newey and West [13].

Table 4 displays the results from the second stage regression that estimates the price elasticity of supply for renewable electricity generators. The variable of interest in this set of regressions is the first row, $Log(\widehat{Total\ Price})$. This is the predicted price of RECs in the region given the shift in demand induced by the stringency of the state RPS estimated in the first stage. Though the elasticity estimates vary across specifications, the preferred estimate in Column 4 is between the other estimates, which allows the other policies to enter in multiple ways.

Column 1 shows a baseline specification without any additional controls, with Columns 2-4 progressing to a full set of flexible controls for other policies aimed at renewable generators. The preferred estimate in column 4 of the price elasticity is 2.714. Thus, for every 1% increase in the price of RECs, there will approximately a 2.7% increase in renewable generating capacity. In the next section I will use this estimate to bound the cost of focusing on reducing greenhouse gas emissions through only an RPS-style policy.

7 Policy Implications for RPSs as a CO_2 Abatement Tool

In this section, I use my estimates of the long-run supply elasticity of renewable generating capacity to estimate the cost of decreasing carbon dioxide emissions in states covered by the Regional Greenhouse Gas Initiative by pursuing carbon dioxide reductions exclusively through an RPS.

The Regional Greenhouse Gas Initiative (RGGI) is a cap-and-trade program established in the northeastern United States to reduce greenhouse gas emissions from electric power plants to 10 percent below (approximately) 2005 levels by 2018. There are currently ten states participating in RGGI, including all of the states in the New England wholesale electricity market, New York, and parts of the PJM wholesale electricity market.[25] In these states, RGGI regulates all fossil fuel fired electricity generators in the 10 states that have a capacity of 25 megawatts or more. Each quarter, new emissions permits are auctioned with approximately 70% of the auction proceeds being invested in energy efficiency and renewable generation projects.

The states in RGGI had a total of 184 million tons of carbon dioxide emissions from the elec-

[25] The ten states currently participating in RGGI are: Connecticut, Delaware, Massachusetts, Maryland, Main, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. The major states in the PJM wholesale electricity market that are not participating in RGGI are Ohio, Pennsylvania, Virginia, and West Virginia.

tricity sector in 2005[26] [1]. Beginning in 2009 and continuing through 2014, carbon dioxide emissions are capped at the baseline level of 188 million tons. Beginning in 2015, the carbon dioxide cap is reduced by 2.5% annually until the final goal is met after 2018 when carbon dioxide emissions are reduced by 10% from the original cap. Under the RGGI cap-and-trade program, emission reductions are most likely to come from using a different mix of fuel to produce electricity (more natural gas and renewable sources, less coal) and energy efficiency investments. This suggests that the carbon price in the RGGI market provides a good cost estimate of reducing greenhouse gas emissions in the electricity sector through ways that differ from an RPS's exclusive reliance on switching production to renewable sources.

I will examine two different levels of carbon reduction produced by a northeastern RPS, a 2.5% reduction of 2005 CO_2 levels and a 10% reduction of 2005 CO_2 levels, to compare to the cost of carbon dioxide abatement through RGGI. In order to estimate the cost of carbon dioxide abatement under an RPS, in addition to knowing the price elasticity of supply or renewable generation that I estimated in the previous section, I need to make a few assumptions. Whenever possible, I will make assumptions that will make an RPS look as favorable (lowest cost of carbon dioxide abatement) as possible so my estimates will be a lower bound on the cost of CO_2 abatement under an RPS.

First, I need to make an assumption about what fossil fuel the new renewable capacity will be displacing. As can be seen in Table 1, coal is the fuel that emits the most amount of CO_2 per unit of heat input at 215 pounds of CO_2 per million British Thermal Units (MMBTU). Therefore, to make an RPS look as attractive as possible, I will assume that each megawatt hour of renewable generation produces no carbon dioxide and replaces a megawatt hour of coal production.[27] To the extent that renewable generation produces carbon dioxide or displaces generation other than coal,

[26]The baseline level of carbon dioxide emissions that the RGGI reductions are based on is 188 million tons of CO_2.

[27]For renewable resources, such as wind, that are not completely predictable, there is some carbon emissions from using these sources since more generators need to be on standby in case the electrical output is less than expected. Compounding this, usually these standby generators need to ramp up their output quickly which creates higher than average emissions per MMBTU consumed. I abstract from both of these issues.

an RPS would have a higher cost of carbon abatement than I estimate.

Secondly, I need to assume a capacity factor (the fraction of the year that a generator produces electricity) for the new renewable generation built to meet the RPS. As discussed above, a capacity factor of 85% is in the upper range for fossil generation and 35% is relatively high for wind generation. I assume a capacity factor of 40% for all new renewable generation that is built for the RPS. This acknowledges that most of the renewable generation being built in response to RPSs are wind turbines, but some is likely to be from other sources with a higher potential capacity factor such as biomass and landfill gas generation.[28]

Finally, I need to assume something about how the demand for electricity changes in the future. I will assume that electricity consumption does not change from the amount consumed in 2005. Likely, electricity consumption will grow between now and 2015 (the first year that the RGGI CO_2 cap is decreased).[29]

In 2005, the total renewable generating capacity in RGGI states was 2,932 megawatts. If every megawatt hour of renewable generating capacity displaces a megawatt hour of coal generation, a 40 percent increase in renewable generating capacity would achieve a 2.5% decrease in CO_2 emissions in RGGI. Using my preferred elasticity estimate of 2.7, this means renewable generators would need a price increase of 15% in order to be profitable. Since the total price of electricity for renewable generators (electricity price plus REC price) averaged $82 per megawatt hour, a 15% increase implies that renewable generators would need to receive approximately $94 per megawatt hour to be profitable. This implies a marginal cost of CO_2 abatement of over $12.

A more reasonable assumption is that each megawatt hour of renewable electricity produced replaces the carbon emissions of an "average" megawatt hour,[30] which requires a 68% increase in

[28]Another renewable source that is included in nearly all RPSs is solar photovoltaics (solar cells). However, these typically have a capacity factor near 15% and are currently too expensive to be deployed on a large enough scale to make a significant contribution to renewable capacity.

[29]Electricity consumption has grown by approximately 2.75 million megawatt hours annually in the northeast between 1990 and 2008. Electricity consumption in the northeast in 2005 was 278 million megawatt hours.

[30]Average is defined as the total tons of CO_2 produced by the electricity industry divided by the number of megawatt hours consumed in a year.

renewable generating capacity. The preferred elasticity estimate tells us that renewable generators would need a 25% increase in price to enter the market. This implies a marginal cost of CO_2 abatement of $35 per ton of CO_2.

The final goal of RGGI is to reduce CO_2 emissions by 10 percent from their 2005 levels. In order to achieve a reduction of this size from an RPS, there would need to be a 163% increase in the renewable generating capacity in RGGI states. In order for my estimate of the cost of CO_2 abatement to be correct, the price elasticity has to be correct for the entire supply curve. While I am comfortable making the assumption that my price elasticity estimate is nearly correct for the smaller changes above, I am hesitant to believe my estimate is correct for this large of an increase in renewable capacity.

With this caveat in mind, I proceed to extrapolate the cost of CO_2 abatement from an RPS that reduces CO_2 emissions by 10% from their 2005 levels. In order to move that far up the long-run supply curve for renewable generation, the total price renewable generators would need to receive for their electricity is $132, implying a marginal cost of CO_2 abatement of $50. If instead of replacing coal generation, renewable capacity replaced the "average" megawatt hour of generation, the marginal cost of CO_2 abatement to decrease emissions by 10% is $140. A summary of these results can be found in Table 5.

These estimates of the marginal cost of CO_2 abatement, ranging from $10 to $140 depending on how much carbon is abated and what fuel the renewable generation replaces, are substantially higher than the expected cost of carbon abatement under the RGGI cap-and-trade system. Currently the RGGI CO_2 emissions permits being traded and auctioned are for the years when CO_2 emissions are capped at a level just over 2005 CO_2 emissions. However, since these permits can be banked indefinitely into the future, they give us a window into the expected marginal cost of CO_2 abatement in the future. Currently the price of emissions permits are at approximately $2 per ton of CO_2, and permits were trading at approximately $3 per ton of CO_2 in early 2009 with an average price of $2.50 per ton of CO_2 over two years of trading. Since permits purchased today can be used to comply with RGGI indefinitely into the future, the current price is indicative of future CO_2 abatement costs. Moreover, the price of contracts for CO_2 emissions permits in 2012 (the furthest ahead future contracts are traded at the moment) is similar to the current price of CO_2 permits further suggesting that prices are not expected to increase.[31]

These results suggest that within the electricity sector, an RPS is an expensive way to decrease carbon dioxide emissions, costing between six and seventeen times more to reduce CO_2 emissions by 2.5% than from a cap-and-trade program. Moreover, since both RGGI and an RPS focus just on the electricity sector, the marginal cost of CO_2 abatement in the economy as a whole is likely lower than either of these estimates since there may be cheaper ways to decrease CO_2 emissions in other sectors of the economy.

8 Conclusion

This paper estimates the long-run supply elasticity of renewable electricity generating capacity. The price elasticity is an important parameter for policy makers to know since many states have introduced aggressive RPSs to increase the share of renewable electricity sold in their states. Also, the US Congress has considered legislation on multiple occasions that would introduce a federal RPS. Since RPSs' main goal are to reduce carbon dioxide emissions, it is important to know the cost of the carbon abatement from these policies relative to other ways that could reduce carbon dioxide emissions.

In order to estimate this parameter, I use the policy variation in the the implementation schedule of renewable portfolio standards across states that have restructured electricity markets. Since most state RPSs can be met by renewable generation located anywhere in the wholesale electricity

[31]RGGI has two mechanisms built into its structure to curb potential price volatility. If the average price of CO_2 permits is above \$7 for a 12-month period, more permits are released and generators are allowed to meet more of their obligations through offsets. If the average price of CO_2 permits is above \$10 for a 12-month period, a second mechanism is triggered and even more offsets can be used to meet CO_2 obligations. It is widely expected that neither of these trigger events will happen, suggesting that it is unlikely that the the marginal cost of CO_2 abatement is below \$10 in the electricity sector in the states in RGGI.

market, I aggregate individual state policies into region-level renewable portfolio standards. Each year, each state's RPS increases in its stringency, creating the variation that I use to estimate the the long-run supply elasticity. In my preferred specification, I estimate that a 1 percent increase in the total price received for renewable electricity (price of electricity plus the price of the renewable energy credit) results in a 2.7% increase in the supply of renewable generation.

Politicians appear to prefer using RPS policies to those of broader policies such as cap and trade or a carbon tax. Part of the attraction is likely that the costs of this method of carbon dioxide abatement are less transparent to voters. However, these policies still come with a cost. My estimates suggest that the cost of abating the last ton of carbon dioxide from an RPS in the northeastern US to reduce emissions by 10 percent from their 2005 levels (approximately equal to a 6 percent RPS) would cost between \$50 and \$140 per ton of carbon dioxide, depending on the type of fossil generation that the renewable generation was replacing. My estimate for the cost of CO_2 abatement is more than 5 times more expensive than the maximum price of CO_2 under the regional cap-and-trade program for the electricity sector. Therefore, residents would be paying a extremely high premium for carbon dioxide abatement under RPSs, even though they appear to be more politically palatable policies.

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9 Tables

Table 1: Environmental Impact of Common Fuels and Frequency of Inclusion in Renewable Portfolio Standards

	Pounds of CO_2 per MMBtu	Percent of States that Consider Fuel as Renewable	Average Generator Size (MW)
Wind	0	1.00	27.3
Solar Photovoltaic	0	0.89	0
Biomass*	0	0.89	14.0
Solar Thermal	0	0.81	17.0
Geothermal	0	0.70	21.5
Hydropower	0	0.70	86.6, 6.0
Nuclear	0	0	999.9
Municipal Solid Waste	92	0.26	26.1
Landfill Gas	115	0.78	1.4
Natural Gas	123	0	62.3
Petroleum	166	0	18.1
Coal	215	0	222.3
Number of States with RPS		27	

CO_2 estimates taken from Energy Information Administration.
* Biofuels contain "biogenic" carbon and are not considered to add to atmospheric carbon levels. [14]

Table 2: Summary Statistics

	Mean	Standard Deviation	Min	Max	N
Active RPS in Region	0.556	0.498	0	1	293
RPS Requirement in Region	0.600	0.747	0	2.476	293
RPS Requirement when Active in Region	1.079	0.697	0	2.476	163
Mandatory Green Power Option in Region	0.041	0.199	0	1	293
Government Purchases of Green Power in Region	0.491	0.501	0	1	293
Public Benefits Fund in Region	0.724	0.448	0	1	293
Net Metering Laws in Region	0.724	0.448	0	1	293
Active RPS in State	0.200	0.400	0	1	1848
RPS Requirement in State	0.339	0.882	0	4.92	1848
RPS Requirement when Active in State	1.698	1.261	0	4.92	369

Table 3: First Stage Regression Estimates

Dependent Variable: Log(Total Renewable Electricity Price)				
	(1)	(2)	(3)	(4)
Log(Average Stringency$_{t,t+5\ years}$)	$0.184{**}$	$0.268{**}$	$0.254{**}$	$0.298{**}$
	(0.047)	(0.062)	(0.058)	(0.068)
$\mathbb{I}$(Green Power Option)		0.074		$0.162{*}$
		(0.061)		(0.071)
$\mathbb{I}$(Gov't Power Purchase)		$0.181{*}$		0.108
		(0.082)		(0.097)
$\mathbb{I}$(Public Benefits Fund)		$0.192{*}$		$0.844{*}$
		(0.086)		(0.317)
Gov't Power Purchase (Frac. of Consumption)			$0.121{*}$	0.103
			(0.053)	(0.066)
Public Benefits Fund (Frac. of Consumption)			-0.081	-0.118
			(0.075)	(0.076)
Net Metering (Frac. of Consumption)			0.010	-0.031
			(0.035)	(0.038)
Observations	293	293	293	293
R^2	0.57	0.59	0.58	0.59
F-test that excluded instrument equal to zero	15.61	18.64	19.05	19.36

OLS estimates. Estimates include region, year, and month fixed effects as well as region specific trends. Standard errors robust to heteroskedasticity and autocorrelation using the Newey-West method. * p<0.05, ** p<0.01

Table 4: Second Stage Regression Estimates

Dependent Variable: Log(Renewable Generating Capacity)				
	(1)	(2)	(3)	(4)
$\text{Log}(\widehat{\text{Total Price}})$	1.810^{**}	3.810^{**}	1.732^{**}	2.714^{**}
	(0.520)	(0.872)	(0.412)	(0.611)
$\mathbb{I}$(Green Power Option)		-0.269		-0.452
		(0.257)		(0.234)
$\mathbb{I}$(Gov't Power Purchase)		0.616^{*}		0.763^{*}
		(0.232)		(0.238)
$\mathbb{I}$(Public Benefits Fund)		0.072		-3.824^{**}
		(0.383)		(0.816)
Gov't Power Purchase (Frac. of Consumption)			0.450^{**}	-0.144
			(0.090)	(0.195)
Public Benefits Fund (Frac. of Consumption)			0.815^{**}	0.750^{**}
			(0.141)	(0.202)
Net Metering (Frac. of Consumption)			0.424^{**}	0.344^{**}
			(0.070)	(0.097)
Observations	293	293	293	293
First Stage F-statistic	15.61	18.64	19.05	19.36

OLS estimates. Estimates include region, year, and month fixed effects as well as region specific trends. Standard errors robust to heteroskedasticity and autocorrelation using the Newey-West method. * p<0.05, ** p<0.01

Table 5: Cost of CO_2 Abatement From an RPS

	Replace Coal	Replace Average Fuel
2.5% Reduction in CO_2 Levels		
Percent Increase in Renewable Capacity	41%	68%
Cost of CO_2 Abatement	\$12.46	\$34.82
10% Reduction in CO_2 Levels		
Percent Increase in Renewable Capacity	163%	273%
Cost of CO_2 Abatement	\$49.86	\$139.28

All CO_2 reductions are measured from the 2005 baseline levels, similarly to the Regional Greenhouse Gas Initiative

10 Figures

Figure 1: Statutory Renewable Requirements for Selected States

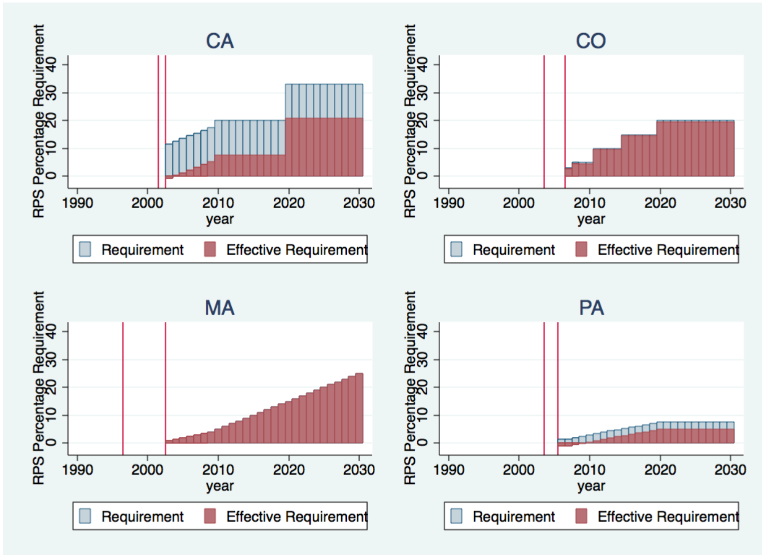

Figure 2: Timing of Renewable Portfolio Standard Adoption

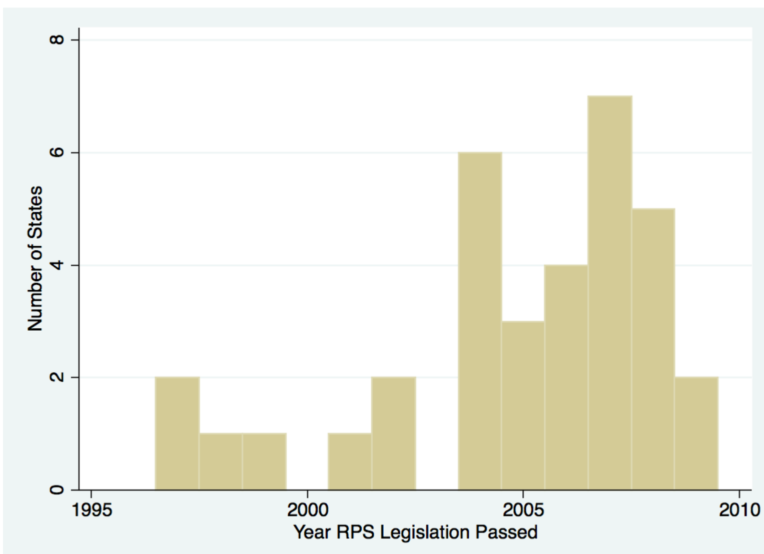

Figure 3: Timing of Renewable Portfolio Standard Adoption by State

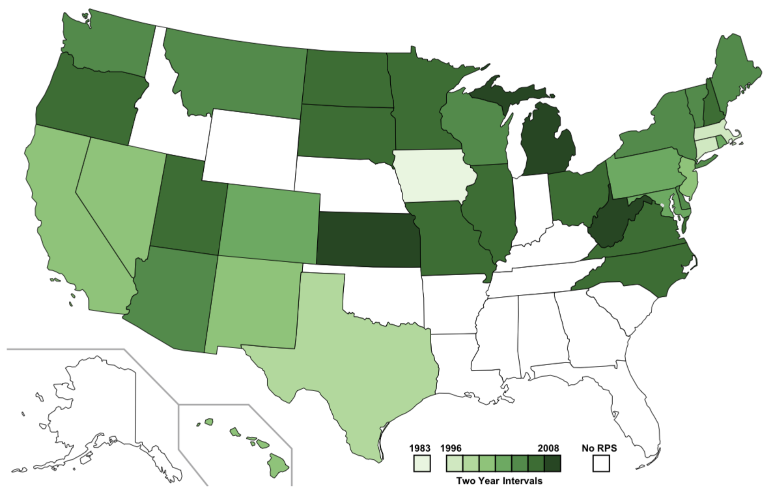

Figure 4: Selected Wholesale Electricity Markets

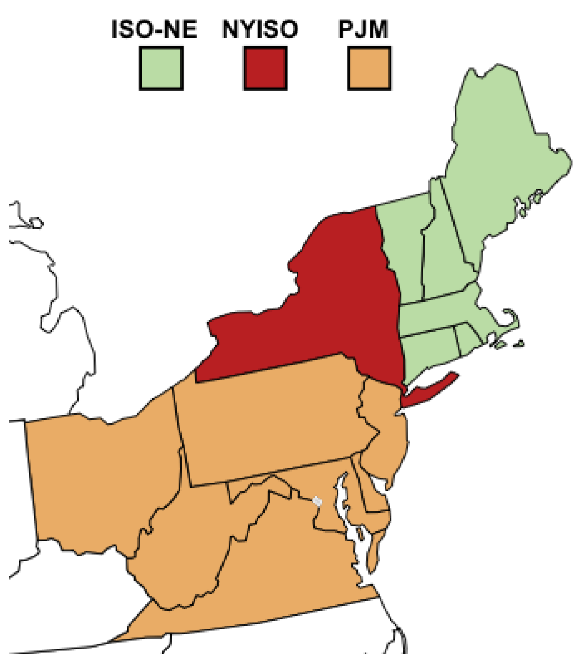

Figure 5: Capacity for Renewable Generation by Fuel

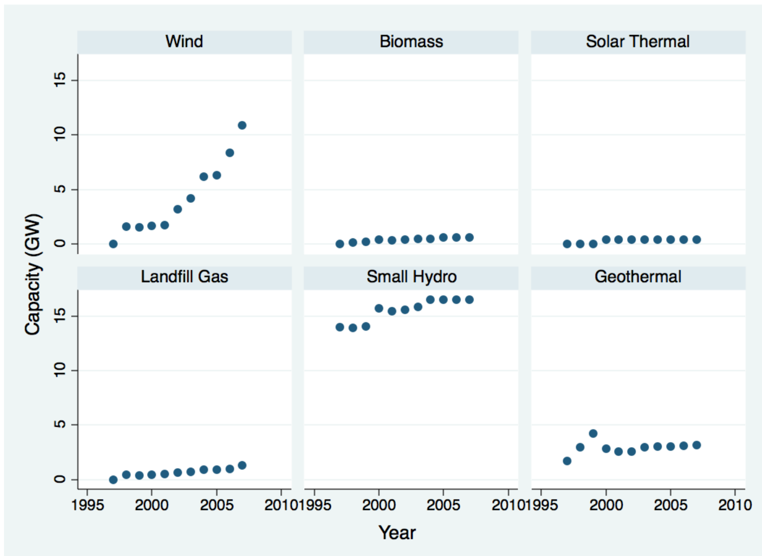

Figure 6: Electricity Capacity Market without RPS

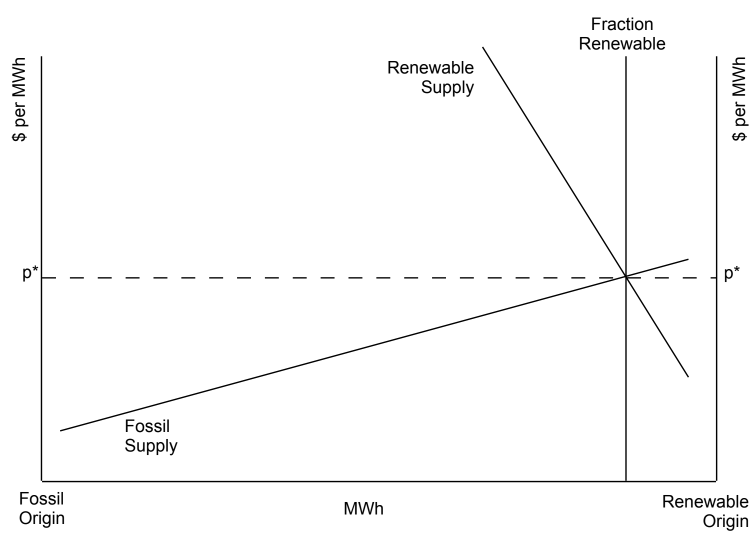

Figure 7: Electricity Capacity Market with RPS

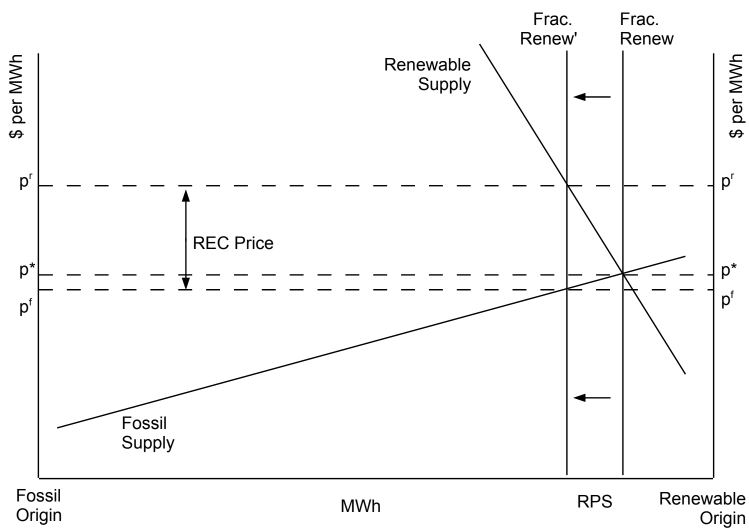

Figure 8: State REC Prices