Estimating the Effect of Electric Generation Technology Mix on Retail Electric Rates

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Introduction

Much public attention has been focused on the energy industries in recent years, particularly the electric generation and petroleum industries. This attention is connected to concerns of global warming and the exhaustion of finite natural resources, with the related question of how to optimally meet our nation's energy needs. One particular point that has received significant attention is the in the mix of resources and technologies used to generate electricity.

Although the electric market is very complex and electricity pricing is a complicated process, this study seeks to illustrate a rudimentary relationship between electric rates and generation technology mix. This study does not purport to be a complete review of the electric market; rather it is intended to provide a starting point to anticipate to what degree changing a state's electric generation asset portfolio will affect retail electric rates. For individuals and groups interested in promoting a change in any state's generation profile, it is important to be able to estimate the expected increase or decrease in electric rates and the associated economic ramifications.

Fossil Fuel Price Volatility and Carbon Emissions

While there are several ways to generate electricity, different technologies have different capital and operating costs associated with them. For example, pulverized coal combustion has traditionally been a low-cost, low-risk way to produce utility-scale baseload electricity. Hydroelectric and nuclear power both have relatively high upfront capital costs and low operating costs. Natural-gas-fired combustion turbines have offered another low-cost generation solution, gaining popularity as a "cleaner" option for power starting in the 1990s. However, natural gas prices have increased dramatically and become generally more volatile as a result of industry deregulation and increased demand. In fact, all fossil fuels have seen increased volatility over the past 5-10 years. This fuel price uncertainty has placed strain on utilities trying to minimize operating costs.

Many people have also become concerned with potential negative side effects of anthropogenic global warming, partially caused by greenhouse gas emissions from fossil fuel combustion. Regulators across the globe have sought to curtail such emissions via international agreements, most noticeable of which is the Kyoto protocol. Domestically, lawmakers have also sought to pass regulations to reduce greenhouse gas emissions. The Lieberman-Warner Climate Security Act[i], which allocates tradable carbon permits, is a notable example of such a bill.

The market stresses of fuel price volatility and pressure to curtail greenhouse gas emissions are perhaps the two largest challenges the electric utility industry is facing today.

Renewable Portfolio Standards: Implementing a Solution

Renewable energy is now viewed as one of the main keys for slowing carbon emissions and mitigating fuel price risk.

The most prominent legislative tool to encourage renewable energy generation has been the Renewable Portfolio Standard (RPS) issued on the state level. RPS is a regulation that requires a certain amount of electric generation be derived from renewable energy resources. Some states have similar legislation under a slightly different name (such as Arizona's Renewable Energy Standard[ii]), but the intent is the same. Although a national RPS has not been signed into law, multiple Congressional bills, starting in 1997, have sought to set a federal renewable energy mandate. In the latest attempt in 2007, a 15% by 2020 national RPS provision was passed by the House by a vote of 220-190, but was subsequently left out of the final energy bill for Senate vote[iii].

Currently more than half of the states (26 plus District of Columbia) have some sort of RPS signed into law, and several more have non-binding goals (see Figure 1). There is significant inconsistency across different states on how each RPS is written. Some states even have special provisions for specific technologies that must be used in the energy portfolio. For example, North Carolina mandates a certain portion of renewable electricity be derived from swine waste and poultry litter[iv] and Nevada requires that 5% of the energy portfolio must be solar[v].

Most RPS legislation is relative new (within the last 10 years). Ohio, the most recent state to pass such legislation as of September 2008, unanimously passed a 12.5% renewable power mandate to be reached by 2025[vi]. This represents a very moderate renewable energy mandate when compared to fifteen states that have requirements of at least 20% renewable power. Illinois' RPS requiring 25% by 2025[vii] is indicative of many states' ambitious drive to lower carbon emissions.

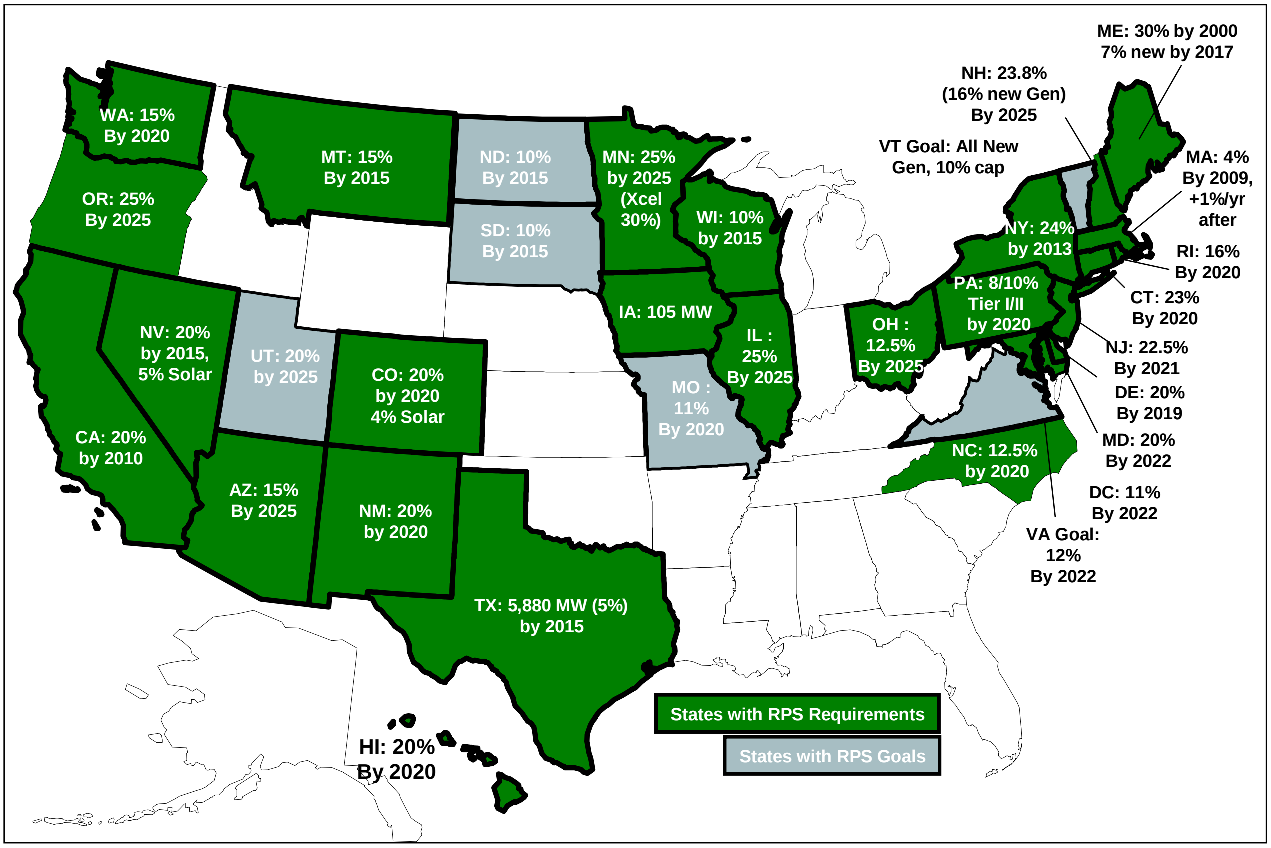

Figure 1. State Renewable Portfolio Standards (September 2008).[viii]

How Will RPS Impact the Cost of Electricity for the Consumer?

Reaching such bold energy portfolio goals does not come without a cost. While many individuals and organizations understand the benefits of "green energy," it is largely unclear to the general public what the actual cost impact of using more renewable energy will be to them. Some recent RPS legislation has sought to protect consumers from significant electricity price increases, such as Illinois which implemented a rate cap of 0.5% per year between 2008 and 2011[ix]. However, most states' RPS legislation leaves out any provisions for such a cap. Hence there is no upper limit on what additional costs (in the form of higher electric rates) consumers will have to bear to help utilities meet the law.

It is important for policy makers and consumers alike to better understand the implications of an RPS. What follows is a limited analysis to provide some understanding on how electric rates may be affected by changing power generation in a given state's technology portfolio.

How Does the Electric Generation Technology Mix Affect Electric Rates?

In 2006 (the latest year for which the Energy Information Administration of the Department of Energy had total US data), the average electric rate in the US across all sectors was 8.9¢ per kilowatt-hr (kWh)[x]. This represents an "all-in" retail price that covers generation, transmission, distribution, and normal business operations. However, there is a wide degree of variation in average electric rates among all states (see Figure 2). In 2006, average rates ranged from a low of approximately 5¢ per kWh in Idaho to nearly 21¢ per kWh in Hawaii.

Electricity prices are a function of the cost of generating assets producing the electricity. In general, utilities that use more expensive technologies must charge higher rates to recover their investment. Hence, the mix of generation technologies has implications on how utilities must price retail electricity.

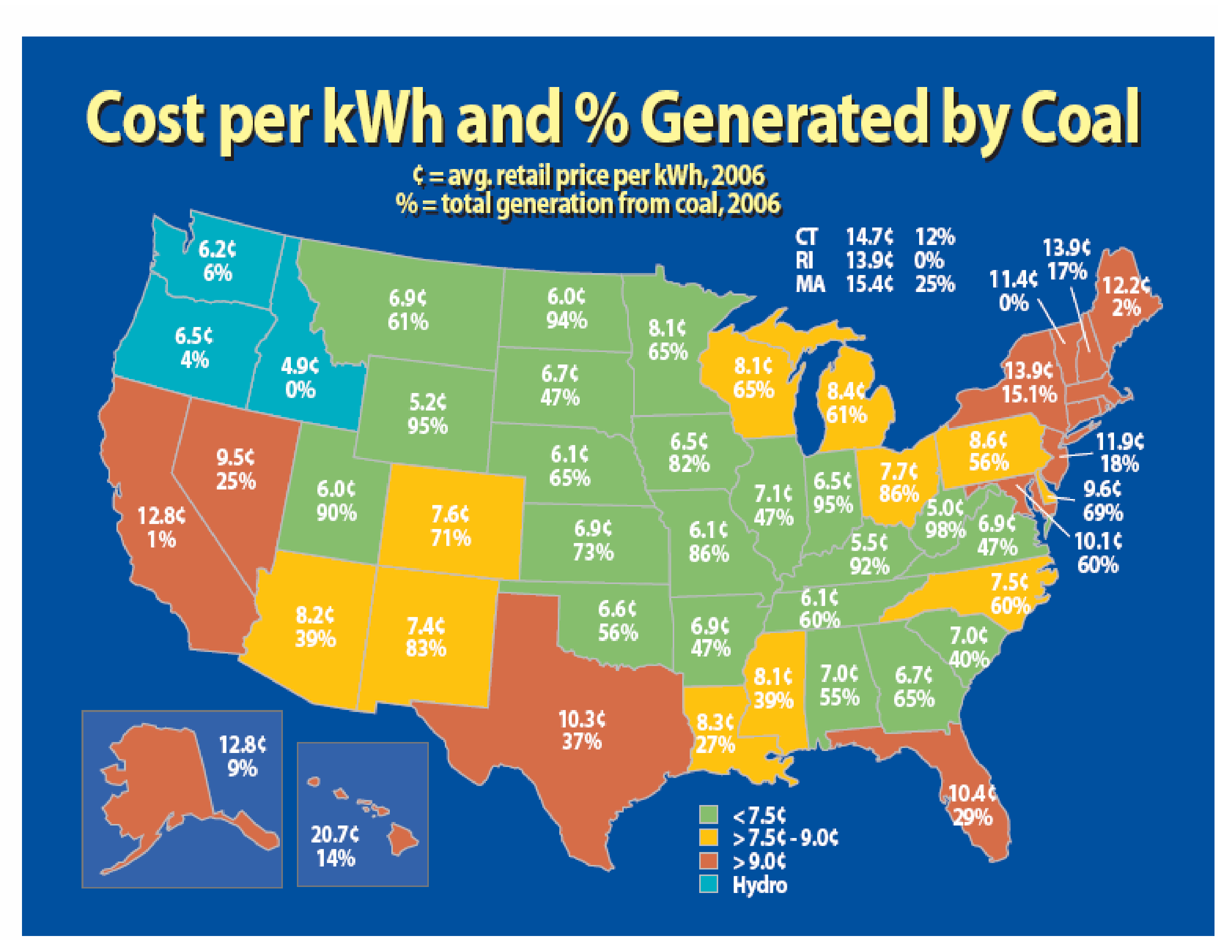

Figure 2. Cost of Power in the US[xi].

Econometric Analysis

This analysis used single year data (2006) to determine the effect on electric generation technology portfolio and customer class mix on weighted average price of electricity. The raw data was taken from the Energy Information Administration of the US Department of Energy. The mathematical model utilized is shown below:

$$
\begin{aligned}
price_i &= \beta_0 + \beta_1(coal)_i + \beta_2(petroleum)_i + \beta_3(natural\_gases)_i \\
&+ \beta_4(hydroelectric\_conventional)_i + \beta_5(other\_renewables)_i \\
&+ \beta_6(residential)_i + \beta_7(industrial)_i + u_i
\end{aligned}
$$

The variables are defined as follows:

- **Price**: the weighted average price of retail electricity for a given state. This is weighted over all utilities and all customer classes.
- **Coal**: the percentage of electric generation within a given state that is derived from coal-fired plants.
- **Petroleum**: the percentage of electric generation within a given state that is derived from petroleum-fired plants.
- **Natural_gases**: the percentage of electric generation within a given state that is derived from natural-gas-fired plants.
- **Hydroelectric_conventional**: the percentage of electric generation within a given state that is derived from conventional (large scale) hydroelectric plants.
- **Other_renewables**: the percentage of electric generation within a given state that is derived from other renewable energy sources. This includes solar, biomass, wind, landfill gas, anaerobic digestion biogas, and geothermal.
- **Residential**: the percentage of retail electric sales within a state that are to residential customers.
- **Industrial**: the percentage of retail electric sales within a state that are to industrial customers.

The null and alternative hypotheses are listed in Table 1. A 95% confidence level was chosen to determine statistical significance.

Table 1. Parameter Hypotheses.		
Variable	**Null Hypothesis Correlation**	**Alternative Hypothesis Correlation**
B_0 (Intercept)	Zero	Positive
B_1 (Coal)	Zero	Negative
B_2 (Petroleum)	Zero	Positive
B_3 (Natural Gas)	Zero	Positive
B_4 (Hydroelectric)	Zero	Negative
B_5 (Other Renewables)	Zero	Positive
B_6 (Residential)	Zero	Positive
B_7 (Industrial)	Zero	Negative

A linear OLS correlation was used, even though it is likely that at least some of the factor relationships to price exhibit some non-linear characteristics. There are two reasons for choosing a linear model:

1. This study was had a limited schedule and was designed to be a first glance analysis of the correlation described above.
2. The generation technology portfolio for any given state changes very slowly. Aggressive plans to alter a portfolio mix may yield a change for any given technology proportion on the order of 10% of over a 10 year period. Dramatic shifts in technology mix simply have not happened in the US electric utility industry.

The model calculated via an OLS estimator using Stata 9 software package. The results are presented in Table 2.

Table 2. Correlation Results.				
Variable	**Coefficient Value**	**t-statistic**	**p-value**	**Significant at 95% Confidence?**
B_0 (Intercept)	11.6¢	3.17	0.003	Yes
B_1 (Coal)	-0.056¢	-2.81	0.007	Yes
B_2 (Petroleum)	0.047¢	1.81	0.078	No
B_3 (Natural Gas)	0.020¢	1.00	0.321	No
B_4 (Hydroelectric)	-0.064¢	-3.10	0.003	Yes
B_5 (Other Renewables)	0.107¢	1.21	0.232	No
B_6 (Residential)	0.016¢	0.22	0.827	No
B_7 (Industrial)	-0.034¢	-0.89	0.377	No
R^2 = 0.66, Adj. R^2 = 0.6083				

The resulting model equation is:

$$price = 11.6 - 0.056(coal) + 0.047(petroleum) + 0.020(natural\_gases) - 0.064(hydroelectric\_conventional) + 0.107(other\_renewables) + 0.016(residential) - 0.034(industrial)$$

As predicted, coal and hydroelectric power have a negative correlation on price. This means that states with high percentages of coal and/or hydroelectric generation typically enjoy lower electric rates than states with higher natural gas, petroleum, or other renewable energy proportions. For every additional percent coal generation, electric rates are on average 0.056¢ lower per kWh. For every additional percent conventional hydroelectric generation, electric rates are 0.064¢ lower. Looking back at Figure 2, it is evident that states with a high proportion of coal generation have lower rates. The Northwestern states of Washington, Idaho, and Oregon also have low rates because of the large proportion of conventional hydroelectric power from the Columbia River basin that serves those states.

This study also suggests that states that serve larger percentages of industrial loads may have lower rates. Industrial power rates are typically lower than residential rates across the country. Given that industrial power customers have high power consumption with strong base load characteristics, it is significantly less expensive to market power to them compared to residential customers. Residential customers are small-scale power users and require a complex distribution network that is more intensive to maintain.

The only variables in the model that were statistically significant at the 95% confidence level were *coal* and *hydroelectric_conventional*. Hence the null hypothesis must be accepted for all variables expect for these two. The model R^2 value suggests that approximately 34% of the electric price variation is explained by factors outside this model.

What This Means for Policy Makers: An Example

The following example shows how the conclusions from this study may be useful. We will assume that all correlations were statistically significant for illustrative purposes.

Let us presume that legislators in Nebraska (currently a state without RPS regulations) were interested in implementing an RPS that required increasing total renewable power to account for 10% greater proportion than is currently produced. And let us assume that the intent of the RPS was to reduce coal generation by the same percentage. The way to achieve this change would likely be to build significant new renewable energy projects to meet growing demand until the renewable energy proportion increased to the right level. How could policy makers estimate the affect that would have on retail electricity customers?

Using this study as a starting point, we can approximate the rate impacts of two parallel effects: the effect of decreasing coal generation percentage and the effect of increasing renewable generation percentage. To approximate those effects, we use the coefficients previously calculated:

- Decreasing coal usage by 10%: (-0.056¢)·(-10) = 0.56¢
- Increasing renewables usage by 10%: (0.107¢)·(10) = 1.07¢
- Total summed effect: 0.56¢ + 1.07¢ = **1.63¢**

Considering that the average rate in Nebraska in 2006 was 6.07¢ per kWh[xii], the estimated rate increase of 1.63¢ represents a 27% increase over the business-as-usual rate. An average household in Nebraska used 989 kWh/month of electricity in 2006[xiii]. Thus the new estimated electric rate would cost the average household an extra $16/month in residential electric bills. In addition, commercial and industrial firms would face increased energy costs that may affect pricing for their goods and services (this model is not capable of handling those effects). With this estimate, policymakers can begin dialogue with state citizens to determine if the benefits of renewable power justify the costs.

Limitations of Study

It should be reiterated that all of the coefficients are not statistically significant in the model as presented. As such, extrapolations using this model must either be considered in that context or allowed a large margin of error. Estimates from this model may provide an order-of-magnitude prediction, but more sophisticated modeling would be necessary for a high degree of certainty.

Factoring in additional variables would improve the accuracy and statistical significance. Some of the principle limitations are presented below:

First, utilities operate in a regulated market environment and for the most part cannot unilaterally change electric rates. Because utilities are government-protected monopolies, permission to change rates, build new assets, change operations, purchase other companies, etc. must be granted by the appropriate state agencies. While this regulatory arrangement seeks to protect consumers, it can simultaneously cause economic inefficiencies in a changing market environment.

Second, this study analyzed electric generation within state borders. However, utilities sell power across state and national borders. Thus, power consumption and power generation are not necessarily equivalent within a given state boundary. A more accurate model would have utilized energy sales, not generation, as the basis on which to calculate generating technology percentage. However, it is not know if the EIA keeps statistics on electricity consumption at the same level of detail as generation. Because the data was not available for this study, the assumption had to be made that electricity generation and consumption within state borders were equal.

Lastly, electric rates are dependent on the ownership structure of the utility. There are three major types of electric utilities:

- Investor owned (IOUs)
- Municipal
- Rural Electric Cooperatives (RECs)

Each type of utility has different operating characteristics and regulatory landscapes. For example, IOUs are profit-seeking enterprises that typically cover a large service area that may encompass multiple states. Municipal utilities are generally much smaller and service a single city or region. RECs are comprised of customers who are also owners with equal vote. RECs typically have higher costs to maintain infrastructure supporting rural areas without large customer bases.

Items for further study

Although this study provides a framework with which to begin analyzing the potential price affects of altering a generation portfolio, there are several additional factors that need to be understood for a more complete picture. Primarily, it would be insightful to deconstruct total generation by the proportion of electricity sold by IOUs, municipal utilities, and coops. Accounting for utility organization would remove any potential model bias from this issue.

Also, there are different renewable energy technologies, each with different operating and cost characteristics. Anaerobic digestion (biogas) generation is typically a baseload source of power, whereas solar power is intermittent and far more expensive on an energy basis. Likewise, geothermal power is very different from wind power. But the data for renewable energy was lumped into one category in this study. Breaking down the variable *Other_renewables* into representative technologies would provide a more accurate correlation and greater insight.

The price of power is also time-dependent. For example, utilities in states that have experienced large population and/or industrial growth recently have had to construct new generating units to keep up with demand. As newer power plants are more expensive than older plants, these utilities have to raise electric rates to achieve their regulated revenues. Analogously, utilities in states with slow load growth are able to rely on existing (less expensive) power plants, and can afford to keep rates lower. Because of this time effect, and other state-specific regulatory effects, it would be useful to use panel data to further analyze the correlations of electric rates. As any given utility's generation portfolio changes very slowly, it would be helpful to obtain at least 15 years of historic data.

Lastly, it would be useful to analyze different functional forms to model the correlation. As described above, a simple linear regression of technology percentages was compared to the price of electricity. However, different functional formats might be more appropriate. For example, historical data may reveal that a logarithmic relationship or power relationship is a better fit for one or more of the coefficients.

Conclusion

RPS legislation has been an important driver to encourage renewable power development. While most people can agree on the benefits of renewable energy, it has not be clear to lawmakers or the general public what the costs of increasing the percentage of renewable power would be to consumers. As electric rates are tied to the underlying costs of the power plants producing the electricity, it is useful to understand how changes in the overall mix of power plant technologies might affect electric rates.

This study shows that the proportion of coal and conventional hydroelectric power are statistically significant indicators of electric rates, while other technologies are not statistically significant in the model presented. Reducing the proportion of coal and hydroelectric power is linked to increased electric rates.

Because the goal of this study was to offer only a broad, beginning view of the effects of RPS on costs to the consumer, it would be beneficial to perform more sophisticated analyses. Accounting for additional pertinent factors (such as more detailed renewable energy technology accounting) and using enhanced techniques (such as panel data analysis) would provide improved insight to the study. It is recommended that this study should be carried forward and improved upon with these changes.

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[i] 110th Congress, 1st Session, S. 2191 (October 18, 2007)
[ii] Arizona Administrative Code R14-1-1801 through 1815
[iii] Nogee, Alan. "Status and Prospects for Federal Renewable Electricity Standard Legislation", Union of Concerned Scientists, June 24, 2008
[iv] General Assembly of North Carolina, Session 2007, Session Law 2007-397, Senate Bill 3
[v] NRS 704.7821
[vi] Ohio 127th General Assembly, Senate Bill Number 221
[vii] Illinois Power Agency Act, 20 ILCS 3855
[viii] Black & Veatch Corporation, derived from the DSIRE Database of State Incentives for Renewable & Efficiency, maintained by North Carolina State University
[ix] Matchett, Barry. "Illinois Renewable Energy & Energy Efficiency Standards", Environmental Law & Policy Center, 2007
[x] Energy Information Administration, US Department of Energy, "Electric Power Annual 2006, A Summary"
[xi] Senate Republican Conference, May 2008
[xii] Energy Information Administration

[xiii] Energy Information Administration, Table 5. U.S. Average Monthly Bill by Sector, Census Division, and State 2006