THE IMPACT OF CO_2 ALLOWANCE PRICES ON RETAIL ELECTRICITY PRICES

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Abstract

Climate change policy is likely on the horizon in the United States. A cap and trade program for CO_2 will result in increased expenses for major emitting firms throughout the economy. Since the electric power sector emits 41% of the nations CO_2 emissions, such a policy will have a significant impact on the industry. Emission allowance costs would represent an additional variable cost to the production of electricity. How these increased expenses will be passed through, from the point of regulation through the value chain to the end user, is an especially important issue in the electricity sector. Because electricity is a vital economic input, the impact of allowance prices on retail electricity rates could have ripple effects throughout the economy.

This masters project examines the potential impacts of a cap and trade program for CO_2 on retail electricity rates. It gives a brief overview of the different treatment of emissions prices in regulated and deregulated electricity markets in the United States. The influence of the SO_2 cap and trade program for acid rain and the European Union Emissions Trading System for CO_2 on retail rates was examined. The potential effect of proposed U.S. climate policy on rates was looked at as well. The retail rate impact of a CO_2 allowance price is likely to vary amongst states, due to differences in regulatory structure and generation portfolios. In order to highlight these variations, the impact of a CO_2 price of $5/ton, $20/ton, and $60/ton on rates in North Carolina, New Jersey, and Washington State was examined.

The analysis showed how any impact of CO_2 allowance prices on retail electricity rates will be dependent upon the state regulatory structure, the allocation of emissions allowances, price of allowances, and the current generation portfolio in the state. Depending on these different assumptions, the resulting increases in retail electricity rates ranged from as low as 0.05% to as high 41% across all three states. Rates in North Carolina and New Jersey increased significantly more than in Washington State, due to its high percentage of hydro-electric power generation. It was also shown that in a scenario with a hybrid of auction and free allowance allocation, regulatory treatment and the point of allocation are the key determinants for the degree of cost pass through from the generator to the ratepayer. The results highlight how key climate policy issues might interact with the fundamental operations of electric power markets to determine the eventual of impact on ratepayers.

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Executive Summary

One of the major issues that policy makers face when crafting climate change mitigation policy is how resulting costs will be passed through to the consumer. Since the electric power sector makes up for 41% of all greenhouse gas emissions in the United States (EPA, 2007), climate change policy will have an impact on electricity rates. The degree to which rates will be affected will depend on the price placed on CO_2 emissions, state regulatory structure, and the generation technology mix of the region. This paper examines these relationships.

Emissions allowance costs are a variable cost in the production of electricity, much like fuel costs. In states where rates are determined through traditional rate of return regulation, the amount of expenses that will be able to be recovered by power generating companies is determined by state regulators. Throughout the paper I assume that regulators would allow utilities to recover CO_2 allowance costs through electricity rates. However, I also assume regulators would not allow any non-monetary expenses to be passed through to retail rates. This implies that the opportunity costs associated with allowances that are allocated for free, but have a real economic opportunity cost, could not be recovered through rates. In contrast, in states with deregulated markets, the emissions costs are embedded in the wholesale price of electricity. In such states, regulators do not have direct control over how variable expenses are reflected in electricity prices, and the opportunity cost of permits would therefore be the included in the market price.

There are several precedents for cap and trade systems, both in the United States and in Europe. Cap and trade programs for sulfur dioxide (SO_2) and nitrous oxides (NO_X) emissions have been operating in the United States since 1995. In 2005, the European Union's Emissions Trading System (ETS) became the first operating market for carbon dioxide (CO_2) in the world. As for CO_2 regulation in the United States, 10 Northeastern States plan on capping CO_2 emissions from electric power plants in a program called the Regional Greenhouse Gas Initiative (RGGI), scheduled to commence in 2009. At the U.S. federal level, several CO_2 reduction proposals are pending before the U.S. Congress. SO_2 cap and trade and the EU ETS both provide reference points for how a cap and trade system for emissions may function, and serve to influence the development of such programs in the United States. This paper explores the impact of these programs on retail electricity rates.

The retail rate impact of a CO_2 allowance price is likely to vary amongst states, due to differences in regulatory structure and generation portfolios across states and regions. For my analysis, I examined the impact of a CO_2 price of \$5/ton, \$20/ton, and \$60/ton on rates in North Carolina, New Jersey, and Washington State using data and assumptions from 2006. Each of these states electricity markets were unique to their region of the U.S. I found that the ratepayers in Washington will be least impacted by a CO_2 price, mainly because if its large endowment hydro-electric power resources. Due to coal's large share in its generation mix, North Carolina ratepayers see the highest percentage increase in their rates relative to no policy of the three states. However, freely allocated permits may not be passed through to ratepayers in a regulated state, such as North Carolina, but passed-through to wholesale prices in a deregulated state such as New Jersey. In addition, New Jersey rates were the highest of the three, both with and without a CO_2 price.

For the final part of my analysis, I examined any potential windfall profits that electric power generators in New Jersey may receive in the advent of a CO_2 price. Windfall profits represent the increased revenues a firm would receive without incurring any extra cost. This occurs in the context of a CO_2 price in the wholesale market, because an allowance price has the potential to raise the price of electricity. If a generator earns more revenue from an increase in prices than they pay for allowances they experience a windfall profit. I also assumed that 100% of the allowances were auctioned, which is consistent with New Jersey's RGGI policy. Because nuclear power releases no CO_2 emissions, nuclear generators stand to benefit considerably from a CO_2 price of just $5/ton, receiving an additional $104 million of windfall profits if they generated their 2006 output of electricity. Natural gas, hydro-electric, and non-hydro renewable energy generators also would have experienced a windfall gain. However, coal and petroleum generators would have experienced a loss, due to the fact that their expenses for allowances would have exceeded any increase in revenues from higher electricity price.

Part A: Background of the relationship between emissions and retail rates

1. Why is cost pass through an important issue?

By placing a price on CO_2 emissions, policymakers will be increasing the cost to burn fossil fuels. This will increase expenses in carbon intensive industries, such as oil and gas, heavy manufacturing, and electric power. How these expenses are distributed throughout the economy is a critically important issue to both consumers and producers. Because of the electric power industries unique regulatory structure, differences in the regional makeup of generation assets, and the diverse collection of industry stakeholders involved, cost pass-through of CO_2 prices in the electric power sector is likely to be especially complex.

The impact of a CO2 price on retail rates is of foremost concern to electric ratepayers. Residential ratepayers might be concerned about how potential climate change legislation could impact their rates before making decisions such as purchasing a new appliance or determining whether or not to weatherize their house. Commercial and industrial customers might want to know the impact of a CO_2 price on their utility expenses. This might impact their operational and long term investment decisions. For instance, firms might elect to purchase more energy efficient equipment or focus on producing less carbon intensive products. Higher rate increases in one region might also cause firms to relocate operations to lower cost regions. This possibility would be of utmost concern to state and local policymakers concerned with local economic development and employment.

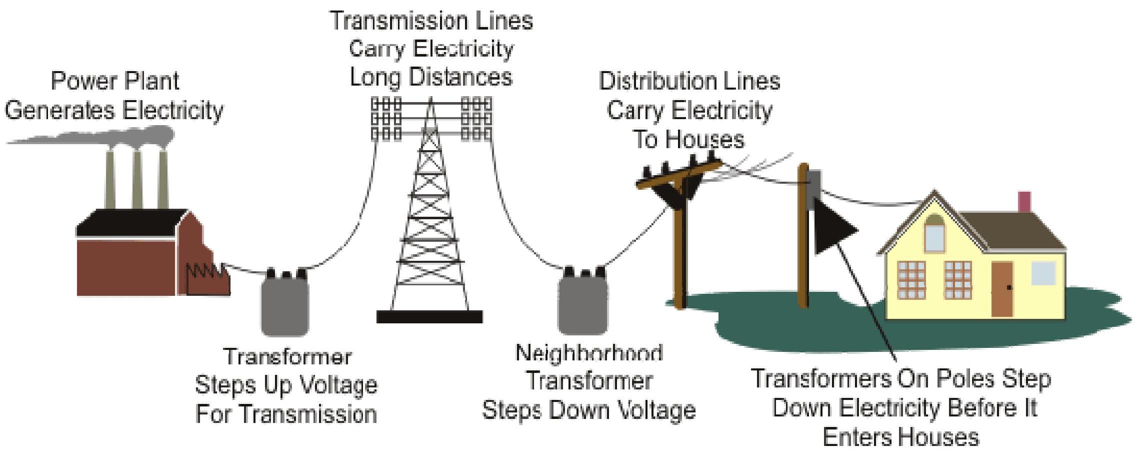
While this paper will look primarily at the cost pass through issue from the perspective of the retail ratepayer, it is important to note how other stakeholders might be affected. A CO_2 allowance price represents and increased expense. Like any product, an electric power generator's profit is determined by how much of their expenses they are able to pass through to their customers. In the power sector, this is heavily dependent upon the makeup of the state's electricity market and decisions by regulatory agencies. Cost pass through of emissions allowances is also a major concern for environmental advocacy organizations, who might object to the idea of polluting firms receiving rights to pollute for free. Additionally, economists and policy analysts concerned with maximizing the societal benefits of such a program might see an efficient cost pass through as an important element to this goal.

The impact of a CO_2 price on retail electricity rates is an important consideration when evaluating current climate change policy in the European Union, and when crafting future policy in the United States. The role of state regulatory structure and allowance allocation methods will play major roles in how these costs are passed through. These issues will be explored later in the paper. Because CO_2 prices are new to the electric power industry in the United States, the actual impacts are yet to be truly known. However, analysis such as the following, will hopefully serve to further the understanding of the interrelation between CO_2 prices and retail electricity rates.

2. Market Structure of Electricity Industry

The electric power industry consists of three major components, generation, transmission, and distribution. A simplified illustration of the electric power sector's operating value chain is shown in Figure I.

Figure I: The Basic Electric Power Sector Operating Value Chain[1]



In the year 2006, the United States produced approximately half of its electricity from coal fired power plants, 20% from nuclear power plants, another 20% from natural gas plants, and 7% from hydroelectric power plants. The remaining came from other fossil fuels and non hydro-electric renewables (EIA, 2006 Electric Power Annual). This mix of fuels used for generation varies by region due to differences in installed capacity, availability of inputs to production, and fuel costs. Generally, power plants are dispatched based on costs of operation. Plants with high initial capital cost and lower operating costs, such as coal and nuclear facilities, are dispatched first, while plants with higher operating costs, such as natural gas and petroleum, are called upon to meet additional demand as needed. The sequence in which power plants operate is typically referred to as the dispatch order.

Electricity must then be transported from the power plant to the user through transmission lines. Once electricity has reached the load center, it needs to be distributed

[1] U.S. Energy Information Administration. "Electricity Basics 101 " http://www.eia.doe.gov/basics/electricity_basics.html

to consumers. Areas with high concentration of users are referred to as load centers. This responsibility can lie in the hand of several different entities. In many states, firms own all generation, transmission, and distribution assets in a designated service area. These companies are referred to as vertically integrated utilities. In other states, generation and distribution services are required to be administered by separate companies. Firms solely designated to distribute power will be referred to throughout the paper as Local Distribution Companies (LDC), while vertically integrated utilities will be referred to simply as utilities.

Government regulation has always played a significant role in the electric power industry. The business operations of electric utilities are closely monitored at the state level by government entities known as Public Utility Commissions (PUCs). One of the main functions of PUCs is to approve the rates charged by utilities operating in their respective state. PUCs face a difficult balance of setting rates at a level that is high enough for the utility to remain profitable, but not so high as to give the utility above market returns, and in the process unfairly burden the consumer. They may also account for other factors, such as environmental protection or economic development in their decision making process. Since regulations and market conditions differ significantly by state, the degree of regulatory impacts on retail electricity price varies nationally.

3. Rate of Return Regulation

In states with vertically integrated utilities, rates are normally calculated through a method known as rate of return regulation. The responsibility of administering this process falls upon the PUC. Their objective is to set rates at a “just and reasonable” level where the firm can recover their cost of operations, while earning a “fair” return on their capital stock. This precedent was solidified in the 1944 Supreme Court ruling in *Federal Power Commission vs. Hope Natural Gas Company* (Bubnys, 1985). Following this decision, the standard process has been for utilities to petition their PUC when they want to change rates through a process known as a rate case. The utility may request an increase after the construction of new assets, change in the state’s regulatory status, merger between utilities, or significant change in market conditions. A rate case generally has two phases, determination of the revenue requirements for the utility, and the structure of how the rates are allocated (Dahl, 2004).

Equation 1

$$\text{Revenue Requirements} = \text{Expenses} + (\text{Fair Rate of Return} * \text{Rate Base})$$

Equation 1 show’s the basic formula which determines the retail price of electricity under rate of return regulation. Utilities expect to recover expenses and earn a rate of return on their existing asset base. The revenue requirement is the product of the expected demand in their operating zone and the price per kWh charged to consumers. The rate base is generally a measure of a utilities capital stock, and the rate of return is determined by observing comparable returns on similar investments in the capital market. The capital cost represents a fixed cost that must be repaid over time, with the revenue stream coming from the sale of electricity generated from the asset.

The expenses represent the variable costs associated with the production of electricity, including fuel and emissions allowance costs. The share of total fuel expense borne by generators is different for different fuels. For instance, nuclear power plants are more expensive to build than natural gas combustion turbines, but the cost of uranium fuel for a nuclear reactor is less than the cost of natural gas. In the presence of a greenhouse gas pricing program, emissions add additional variable costs to the production process. Therefore, a carbon intensive fuel such as coal would increase operating expenses more than natural gas.

Under rate of return regulation, annual fuel costs are generally reported by the utility to the PUC, and they allow this cost to be included in retail rates. However, in the case of emissions allowance permits, the extent of the pass through may be dependent upon the allocation of allowances. If permits are allocated for free, a utility may not face any direct monetary cost for permits. There is an opportunity cost associated with freely allocated permits, because they can be sold instead of being used to cover emissions. However, if there is no monetary expense, it might be difficult for a utility to convince regulators to include these costs as an expense. If the permits were auctioned, or if there were a per-unit tax on emissions, generating electricity would incur an additional monetary variable cost that could be viewed as a recoverable expense. The decision on how such expenses would be treated is ultimately that of the PUC. Therefore, under rate of return regulation, PUCs will play a critical role in the degree electricity consumers bear the price of CO_2.

4. Regulated vs. Deregulated Markets

Since the 1980's, many economists, policymakers, and business leaders, argued that as new dynamics in the power industry developed, a competitive generation market would be more efficient. In 1996, California became the first state in the U.S. to establish a wholesale electricity market. The enacting legislation required vertically integrated utilities to divest their generating assets, but still retain control of their retail distribution and transmission assets. Therefore, they were still responsible for distribution and transmission, but not generation. By 2000, several states had followed California's lead and deregulated their markets. However, between 2000 and 2001 California experienced a series of rolling blackouts and price spikes that resulted in the state suspending deregulation. The causes of the crisis are generally believed to be a result of flaws in the design of the market, illegal market manipulation, and underinvestment in new generating assets (Timney, 2004). After California's problems, further restructuring efforts in other states were halted. However, wholesale power markets have continued to operate in 14 states and the District of Columbia without the serious problems faced in California (EIA, 2007).

In a competitive market, the wholesale price is set by the marginal cost of generating one additional megawatt-hour of electricity. When demand is lowest, typically only large coal and nuclear power plants operate. These are referred to as base load plants. This is because of their relatively low variable cost, and their large scale makes it uneconomical for them to shut down on a routine basis. During times of the day when demand is high, additional power plants are brought online. These facilities, referred to as peak load plants, are usually natural gas turbines or diesel generators. They are generally more expensive to operate mainly due to relatively high fuel costs.

Cost pass through of variable costs in a deregulated market works differently than in a traditionally regulated market. In a vertically integrated market, variable costs for each utility are directly considered by the regulator when determining retail rates. However, in a deregulated market, this cost is bundled into a wholesale price that is seen on the open market. While local distribution companies (LDCs) still have their retail rates set by the state PUC, the price of the electricity these firms purchase is set in the wholesale market. Any marginal increase in the cost of generators resulting from fuel or emissions permits would be seen in an increased wholesale price of electricity. Since the PUC is a step removed in the ratemaking process, it does not have direct control of how these costs might be passed through.

In wholesale markets, the emissions costs that can be passed through are not the same for all fuels. Emissions allowances change the price of electricity. The degree of this change depends upon the emissions resulting from each particular fuel. For instance, burning natural gas results in approximately half the CO_2 emissions from burning coal. If natural gas is the marginal fuel, the incremental increase in wholesale price of electricity would be equivalent to the increased emission costs faced by natural gas operators. Therefore, the incremental increase in electricity price would be lower than the cost to coal generators. In this scenario, the profit margins of coal generators would shrink, while natural gas generators would be able to recover all their costs. Generators with no carbon emissions, such as nuclear power, benefit significantly from such regulations because they wouldn't incur any increased costs, yet would receive higher revenue from a higher price of electricity.

5. Sulfur Dioxide Emissions Cost Pass-through under the Clean Air Act

A cap and trade program for emissions of sulfur dioxide (SO_2) has been operating in the United States since 1995, and is viewed as having been very successful in reducing emissions and mitigating the acid rain problem in the eastern United States. Since emissions from coal power plants are the primary source of SO_2, the program provides a reference point for a general understanding of the cost pass through of emissions allowances in the electricity sector. Mechanisms, such as a cap and trade program, allow generators to exercise the lowest cost option when reducing emissions. In the case of SO_2, this can be accomplished through the use of low sulfur coal, installation of pollution control equipment, the purchase of additional allowances, or a change in the dispatch order.

97% of all SO_2 allowances are allocated each year to facilities based off of their historical emissions. The remaining 3% are made available through an annual auction administered by the Environmental Protection Agency (EPA). The amount of allowances allocated is designed to incrementally decrease over time. Generating facilities face a choice of whether to use the allowance to cover emissions, or sell them. The fact that they can profit from emitting less than they are allocated, gives allowances an opportunity cost, even if there are initially allocated at no cost. If a generator plans on emitting more pollution than they have in allowances, the expenses they incur purchasing additional allowances are usually treated as an expense similar to fuel.

The electric power industries compliance strategy for the program has been heavily shaped by state regulators. It has been observed that in the early years of the program, PUCs may have lead power generators to make decisions that were not the least cost. PUCs have tended to discourage emissions trading and encourage investment in capital equipment such as flue gas scrubbers. Burtraw and Lile (1998) catalogued PUC responses to the Acid Rain program. They found that in most traditionally regulated rate of return markets, utilities where able to pass the costs of permits purchased through to retail rates. However, they were almost always required to credit ratepayers for any revenue gained from selling permits. This may have discouraged utilities from participating in the emissions permit market, because they did not stand to gain any added revenue by selling permits.

Meanwhile several capital intensive pollution control projects were allowed into the rate base. If a utility had the opportunity to earn a rate of return on investing in equipment, it would have been better off installing the equipment than trading allowances. However, from an overall economic efficiency standpoint, it may have cost the ratepayers less if they had simply purchased allowances. It was estimated that in 1996, PUC rulings allowing SO_2 scrubbers into the rate base lead to cost increases ranging from 4.5% to 139% above the least cost option (Sotkiewicz, 2003). These evaluations of the Acid Rain Program, have showed the important role of state regulatory agencies in a cap and trade program. These issues may reappear in regards to CO_2. In states with rate of return regulation, expensive capital intensive projects, such as nuclear power plants and carbon sequestration and storage, will very likely be recoverable through the rate base. Therefore, the impact on ratepayers may be higher if a local utility opts to construct such equipment rather than purchase allowances in order to meet their cap.

6. Carbon cost pass through in European Union Emissions Trading System

In 2005 the European Union established a cap and trade system for CO_2 known as the Emissions Trading System (ETS). Despite the differences in electricity regulation at the retail level between the United States and EU countries, there are still lessons for U.S. policymakers to learn from ETS. The ETS applies to 6 sectors of the economy including electric power. Eight of the 25 EU countries participating in ETS, including Germany, The Netherlands, and France, all had operating wholesale electricity markets when the ETS began in 2005. Therefore, market behavior in the ETS provides a natural experiment for how a carbon policy might impact wholesale markets in the U.S. Each country was allocated permits based off of historical emissions and distributed the permits to industry in their respective countries. Almost all of the permits distributed in 2005 and 2006 were allocated at no cost.

Sijm, Neuhoff, and Chen (2006) found that a €20/ton cost of CO_2 lead to an increased cost of electricity from anywhere between €3/MWh to €18/MWh in countries with wholesale electricity markets. The exact amount was determined by the marginal fuel of generation in each country. For instance, in Germany where the marginal fuel was coal, the increased cost of electricity due to CO_2 was higher than in the Netherlands, where the marginal fuel was natural gas. France, who generates 80% of their electricity from nuclear power, showed only a slight increase in wholesale power prices. Using an ordinary least squared regression model, the authors were able to estimate cost pass through due of CO_2 allowances. This regression models is shown in Equation 2. The β_2 coefficient is intended to represent the impact of a change in CO_2 price on wholesale electricity price.

Equation 2

$$\text{Wholesale Price} = \acute{\alpha} + \beta_1 CO2 + \beta_2 \text{ Fuel Price} + \acute{\varepsilon}$$

In Germany, estimated pass through rates ranged from 100% to 60% depending on whether or not it was from a peak or off-peak load period. In the Netherlands, the range was slightly smaller, with 78% of the costs pass through during peak hours and 80% during off peak hours. The smaller pass through during peak hours in the Netherlands was likely due to natural gas as the marginal fuel instead of coal.

The EU ETS resulted in some power producers generating windfall profits. This occurred because they were allocated allowances for free, yet were still able to pass through the increased costs in their rates. Windfall profits in the Netherlands alone were estimated to be anywhere from €300 million to €600 million annually in 2005 and 2006. This is equivalent to an approximate €3 to €5 for every MWh produced. These windfall profits have been controversial, because they resulted in ratepayers bearing the cost of carbon policy, while many power producers saw increased profits. Due to this initial experience, policymakers in the EU are considering making auctions the primary method of allocation in the post 2012 phase of the ETS (EU Directive, 2008). The EU experience, may also serve to guide policymakers in the United States on how design a more efficient policy that is perceived as more fair by ratepayers (Reilly, 2007).

7. Cost pass-through in RGGI

The Regional Greenhouse Gas Initiative (RGGI) will be the first carbon cap and trade program in the United States. It will take effect on January 1st. 2009. Ten Northeastern States[2] will be participating in the program, which caps CO_2 emissions from electric power plants with a capacity 25 MW or greater. The plan limits emissions in the region to 188 short tons of CO_2 annually by 2015, and it tightens the cap by 2.5% each of the following years until 2020. RGGI will also represent the first time where auctions are the primary method of allocation in a cap and trade program. All participating states are required to auction at least 25% of their permits. Most states have decided to auction a majority. As of February 2008, 175 million out of the 188 million permits to be allocated through the program are scheduled to be auctioned in 2009 (Kahn, 2008).

All RGGI states except Vermont have deregulated electricity markets. Therefore, in all participating states but Vermont, the price owners of generating facilities pay for permits will result in an increase in the wholesale price of electricity. The degree of this increase will be dependent on the marginal fuel and on changes in demand. If demand decreases, due to a price rise or through energy efficiency programs, additional peak generation may not be needed, and the marginal fuel may change. Since least cost generation is

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[2] New York, New Jersey, Connecticut, Massachusetts, Maryland, Delaware, Rhode Island, Vermont, New Hampshire, & Maine.

dispatched first, if demand is reduced by a large enough amount, a more expensive peak generator may not need to be dispatched. This would result in electricity prices, because the wholesale price is set by the marginal generator. Energy efficiency is a strategy that will be employed throughout RGGI to reduce emissions and costs. The degree to which these policies are successfully implemented will be a key determinant in keeping the costs of the policy low.

Several modeling analyses have estimated the potential future costs of RGGI to electric ratepayers. Wholesale power modeling completed by ICF Consulting (2005), determined that RGGI could increase the annual household expenditure on electricity in 2021 from anywhere between $3 and $22. However, if energy efficiency assumptions were included, RGGI actually resulted in net savings per household. The results are shown in Table I below. Total economic impacts in the RGGI region were estimated as being below negative two-hundredths of 1% of regional GDP without energy efficiency, and show a slightly positive effect on the order of two- to three-hundredths of 1% when energy efficiency was included (REMI, 2005).

Table I: Projected RGGI Regional Household Impacts in 2021 ($/yr)

	No Energy Efficiency	**Energy Efficiency**
Standard Emissions Reference	$5.25	($50.24)
High Emissions Reference	$22.44	($37.24)

Source: http://www.rggi.org/docs/rggi_household_bill_impacts12_12_05.ppt

The following is a summary of each RGGI state's proposed approach to auction and their use of the auction revenue as of April of 2008. Since the program is set to commence in January 2009, all participating states should have comprehensive plans in place by then.

- New York – Deregulated Market (NYISO): Plans on auctioning 100% of allocated permits and using 100% of the revenue for Energy Efficiency Projects.
- Connecticut – Deregulated Market (NEISO): Plans on auction 91% of permits and using 70% of the auction revenues for energy efficiency projects.[3]
- New Hampshire – Deregulated Market (NEISO): Undecided
- Delaware – Deregulated Market (PJM): Undecided
- New Jersey – Deregulated Market (PJM): 100% of allocated permits auctioned. $2/ton discount to generators locked into long term supply contracts. 100% of auction revenue dedicated to energy efficiency projects.
- Vermont – Regulated Market: 100% of all permits auctioned. Revenues from auction will be used to directly offset any rate increases due to the carbon adder. Carbon cost will now be included in subsequent rate cases.[4]
- Maine – Deregulated Market (NEISO): Committed to 100% Auction. Allocation of auction revenue is yet to be determined
- Maryland – Deregulated Market (PJM): Committed to 100% Auction. Maryland plans on implementing a $7/ton safety valve through 2012. Allocation of auction revenue is yet to be determined.
- Rhode Island – Deregulated Market (NEISO): Committed to 100% auction. Allocation of auction revenue is yet to be determined.
- Delaware - Deregulated Market (PJM): Percent of permits auction is still to be determined.

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[3] Personal Communication with Chris Nelson, Connecticut DEP. February, 1st 2008
[4] Personal Communication with Dick Valentinetti, Vermont DEC, January, 31st, 2008

The decision to use auctioning as the primary method of allocation was due in a large part to experiences of the European Union with the EU ETS. According to Christopher Nelson, Director of Energy and Climate Programs at the Connecticut Department of Environmental Protection, "the anecdotal evidence from several previous cap & trade programs has informed the RGGI Agency Heads and thus helped move the states toward the auction route."[5]

8. Federal Climate Legislation

Several proposals for greenhouse gas regulation have been introduced in the U.S. Congress. Many key stakeholders in the debate are associated with the electric power industry. Private sector stakeholders include vertically integrated utilities, merchant generators, load serving entities in deregulated states, and other energy intensive industries that rely heavily on electricity. Other key stakeholders include federal agencies, state governments, specifically PUCs and ratepayer advocates, environmental organizations, and general congressional watchdog groups. One interested party in cost pass through is the National Association of Regulatory Utility Commissioners (NARUC). A major concern of theirs is maintaining the exclusive jurisdiction of state PUCs in the setting of rates in their states (NARUC Resolution, 2007). Therefore, controlling the point of regulation would give state commissioners an ability to directly influence the retail impacts of the policy (Keeler, 2008).

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[5] Personal Communication Chris Nelson, Connecticut Department of Environmental Protection. February, 1st, 2008

The Lieberman-Warner “Climate Security Act” (S.2191), was introduced in the Senate in October 2007. It calls for reducing CO_2 emissions 19% below 2005 levels by 2020, and 63 % below by 2050. It also incorporates NARUC’s recommendations about allowance distribution to load serving entities. Section 3500 directs 10% of all permits allocated annually be distributed at no cost to local distribution companies. They would be required to sell the permits within a year, and all sales from these permits would be used to mitigate any rate increases for middle to low income ratepayers as well as fund energy efficiency projects. The most recent version of the bill, as of March 2008, raises the percentage of permits auctioned from 21% in 2012 to 69% by 2050, but the permits allocated to load serving entities remains constant at 10% (U.S. Senate 2191, 2007).

A recent modeling study conducted on the Environmental Protection Agency, concluded that the legislation could potentially raise electricity prices by as much as 46% from a baseline scenario with no carbon policy by 2030 (U.S, EPA, 2008). This percentage increase was based on projected CO_2 prices ranging from $61-$83/ton that came from modeling done for the study. It should be noted that this high CO_2 price, and the corresponding 46% increase in electricity price is, is projected for 2030. It is most likely that near term CO_2 price will be much lower. It is also noted by the EPA, that the 44% increase is in the cost to generate electricity. Therefore, it includes that if allowances were allocated freely to vertically integrated utilities and local distribution companies, the retail rate impact would be lower. Lieberman-Warner also calls for the establishment of an independent oversight entity called the Carbon Market Efficiency Board (CMEB) as a cost containment mechanism. One of their primary functions would be to monitor the price of allowances, and ensure that they do not exceed a level that would be damaging to the economy.

Another senate proposal that has received attention is the Bingamam-Spector “Low Carbon Economy Act” (S.1766). The act caps emissions to 2006 levels by 2020 and 1990 levels by 2030. It stipulates 24% of all allowances be auctioned off in the year of the policies inception, leading to an eventual 54% auctioned by 2030. It also allocates 54% of all free allowances directly to the electric power sector, with an additional 9% allocated to state government. Therefore, the bill also provides the opportunity for public utility commissions to directly influence cost pass through. The bill caps the price of CO2 at $12/ton, limiting the overall cost of the policy. This price cap has been referred to as a “safety valve.” A recent analysis by the Energy Information Administration (EIA, 2007) showed that the bill would result in an 8% to 10% increase in retail electricity prices. This lower percentage increase in retail rates for Bingaman-Spector than seen in the EPA analysis on the Lieberman-Warner bill is likely due to the safety valve provision.

Part B - Projected Retail Rate Impact Analysis

<u>1.1 Background & General Assumptions</u>

The impact of CO_2 allowance costs on retail rates will vary by state due to differences in generation mix, regulatory structure, and demand characteristics. Any analysis of cost pass-through needs to take account of the unique market elements of each state. For this project, I examined three states, North Carolina, New Jersey, and Washington State. These three states where chosen to represent different geographic regions, regulatory regimes, and generation mixes. North Carolina and Washington State are both regulated states, while New Jersey is a deregulated state operating in the PJM wholesale market. These differences in regulation are the basis for key assumptions made in the analysis.

I assumed that generation output was from 2006. I also assumed no fuel switching, capital investment turnover, demand response, or technology investment. These assumptions limit the ability of my analysis to estimate retail prices further into the future. However, understanding the immediate impacts of a CO_2 charge on ratepayers can have a good deal of value. Understanding how a CO_2 price might fit into current retail electricity rates might aid in quantifying near term economic impacts. It also may provide a good basis before examining how more dynamic assumptions over time might change such costs.

Because this analysis is used to measure the short term impact of CO_2 allowances on rates, assumptions such as capital investment turnover are less applicable. It may take several years for utilities to retire old generation facilities and commission new ones. More advanced electric power market modeling tools have been used to determine how different policies and regulations impact fuel switching, demand response, and technology investments over time in different regions. These are beyond the scope of this paper, but it should be noted that electricity market models are extremely valuable in any type of electric power industry analysis.

For all three states, the following common assumptions were used.

- The units of CO_2 are defined in metric tons. This is consistent with the units specified by RGGI, ETS, and all pending federal climate legislation.
- Specific unit conversions, emissions factors, and equations used are shown in Appendix I.
- Revenue from the sale of permits is not considered. However, as specified in Lieberman-Warner (S.2191), Bingham-Spector (S.1766), and the New Jersey "Global Warming Solutions Act", a large portion of the auction revenues will be used to invest in energy efficiency programs and to help mitigate rate increases to low income and middle income ratepayers.
- The point of regulation occurs at the point of emissions. This is consistent with the Lieberman-Warner (S.2191) and Bingaman-Spector (S.1766), provisions for the electricity sector. This is also the point of regulation that is defined for the RGGI states. However, it should be noted that in Bingaman Spector, the point of regulation for other industries, such as coal and natural gas, is upstream of the emissions point.

1.2 Allocation Scenarios

I explored two scenarios. For the first scenario, I assumed that all of the CO_2 allowance costs were passed through to the ratepayer. Therefore, for every ton of CO_2 emitted by the state's generators, ratepayers would bear the full impact. This could occur through a tax or 100% auction scenario. In this scenario, state regulatory regime did not matter because all costs were allowed to be passed through. As noted previously, New Jersey plans on auctioning 100% of its allowances for RGGI. Therefore, this scenario is consistent with how it plans on dealing with an initial cap and trade program. In the case of the regulated states, North Carolina and Washington, I assumed that since all allowances would represent a monetary expense to the utilities, state regulators would allow them to pass through the costs to retail rates. Currently there is no state climate policy for these two states. Therefore, these assumptions are hypothetical.

In the second scenario I assumed only half of the allowances were allocated through an auction. This scenario was used to better represent the mix of free and auctioned allocations in a federal program. As mentioned earlier, Lieberman-Warner specifies that only 21% of allowances in the policy's first year are to be auctioned, with the share incrementally increasing up to 69% by 2050. Bingaman-Spector begins auctioning 24% of all permits, and incrementally increases this percentage to 53% by 2030. Therefore, although the 50% auction scenario I assumed, might not be the exact mix of auction and free allocation specified by one of the two policies, it provides a reasonable estimation of how such a mix would change the impact on retail rates.

I assumed in the first scenario that the PUCs in regulated states would be allow utilities to pass through any monetary expenses incurred by purchasing allowances in an auction. For the second scenario, I assumed that PUCs in North Carolina and Washington State, the regulated states, would not allow allowances allocated for free to be passed through, because they did not represent an increased monetary expense. However, in the case of a deregulated state such as New Jersey, I assumed that allowances were fully passed through regardless of the method of allocation. This was based on the assumption that they were allocated to generators, where they became embedded in the wholesale price. Therefore, PUCs in deregulated states would not have jurisdiction over the pass through of costs. An exception to this would need to be made if allowances were allocated to free to local distribution companies downstream of the wholesale market, but these assumptions were not included in my analysis.

1.3 Incremental Increase in Electricity Price from CO_2

In order to examine how a price of emissions would eventually impact retail rates, I needed to first determine how a carbon price might increase the cost of generating electricity. I multiplied amount of electricity generated by coal, natural gas, and petroleum, in each of the three states by an assumed emissions factor specific for each fuel in order to get the total amount of emissions per fuel in pounds of CO_2[6]. After converting pounds to metric tons, total emissions were multiplied by an assumed CO_2 price to give the total increased expenditures for each fuel. These expenditures incurred were then divided by the total generation for each fuel to give the increased costs of generating one megawatt of electricity from each fuel. Because of the fact that the assumed emissions factors and CO_2 prices were the same across states, the incremental cost increases were the same as well. This method is demonstrated below and the results are displayed in Table II.

Generation by fuel (MWh) * Emissions factor (lbs/MWh) = lbs of CO2

- ➔ lbs of CO2 -> Metric Tons of CO2
- ➔ CO2 (Metric Tons) * Allowance Cost ($/ton) = Total expenses ($)

[6] Emissions factor assumptions were taken from the U.S. Energy Information Administrations "Voluntary Reporting of Greenhouse Gases, 2004." http://www.eia.doe.gov/oiaf/1605/archive/vr04data/

➔ Total Expenses ($) / Generation by fuel = Incremental cost increase ($/MWh)

Table II : Incremental cost of generating from a carbon charge				
	Emissions Factor(lbs/MWh)	**$5/ton**	**$20/ton**	**$60/ton**
Coal ($/MWh)	2026	$4.60	$18.38	$55.15
Natural Gas ($/MWh)	1113	$2.52	$10.10	$30.30
Petroleum ($/MWh)	1821	$4.13	$16.52	$49.57

2. Projected Retail Rate Impacts in NC

2.1 Background and Assumptions

91% of North Carolina's electricity customers are served by the two vertically integrated utilities *Duke Energy Carolinas* and *Progress Energy Carolinas*. The rates they charge are determined through traditional rate of return regulation set by the North Carolina Utilities Commission (NCUC). In 2006 these utilities accounted for 94% of all electricity generation within the state. Coal power accounted for 61% of in-state generation, followed by nuclear power plants at 34%. Natural gas and hydroelectric plants made up approximately only 2% each (EIA, 2006 State Electricity Profiles). The large share of coal suggests that the two utilities may face significant increases in their generation expenses in the advent of carbon regulation. The current political climate in the state indicates that any carbon regulation would be the result of a national program, as opposed to state-level regulation. Since retail rates are set by the NCUC, they would have the authority to pass potential costs CO_2 to the state's retail consumers.

The following analysis estimates how a price placed on CO_2 could potentially influence retail rates, assuming current generation mix and fuel prices. It assumes increased operating costs will be included in the fuel adjustment portion of the rate. Current state law requires that utilities petition the North Carolina Utilities Commission annually to adjust rates based on the previous year's fuel costs, through what is referred to as the fuel adjustment charge (FAC) hearing. The FAC consists of an average of the per kWh fuel costs for different fuels, weighted by their share in the utilities generation portfolio. The costs for sulfur dioxide permits are included in this charge. Therefore, for the purpose of this analysis, it will be assumed that any additional costs of CO_2 would be placed in FAC.

2.2 Data Collection

I collected North Carolina electricity data from two sources. The basic characteristics of each electrical generating facility in North Carolina during the year 2006, was taken from the EIA Annual Electric Database, (EIA Form 860, 2006). Information on annual per unit generation and per unit fuel price was taken from each utilities most recent FAC hearing. Progress Energy's data, from March 2006 through March 2007, was taken from their latest FAC documents filed on June 8th, 2007 (NCUC, Docket E-2 Sub 903). Progress Energy's fuel adjustment charge amounted to \$0.0101/kWh. Duke Energy filed its latest request on March 2nd 2007 (NUCU, Docket E-7 Sub 825), and their data was from the calendar year 2006. Duke Energy's fuel adjustment charge was slightly higher at \$0.0178. Some of the facilities in the FAC calculation were located in South Carolina. Since they were part of the FAC calculation, I included these facilities in my analysis.

2.3 Methodology & Analysis

The following analysis is a calculation of weighted average increase in costs to generate electricity that would occur as a result of a CO_2 price. The units reported are in \$/kWh, which is the standard measure used for retail electricity rates. In order to determine the statewide incremental increase in electricity price due to CO_2, it was necessary to calculate the generation mix and use the incremental increase in cost of generation values already determined in Table II. Multiplying the incremental cost of each fuel by the generation mix percentage obtained a weighted cost increase for each fuel. The sum of these results produced what is referred to as an “adder” to current retail rates. Table III shows the calculation of this adder. The two major determinants in the adder were the increased cost of generation due to CO_2 and the percentage of the generation mix of each fuel. Coal was the dominant driver of the price increase due to 48% share of generation and because it’s high carbon content caused higher emissions than the other fuels considered.

Table III: Weighted incremental cost of carbon by fuel in NC

	Generation[7] Mix	Adjusted $5/ton Incremental Increase	Adjusted $20/ton Incremental Increase	Adjusted $60/ton Incremental Increase
Coal	47.94%	$0.0022	$0.0088	$0.0264
Natural Gas	1.31%	$0.0000	$0.0001	$0.0004
Petroleum	0.04%	$0.0000	$0.0000	$0.0000
Nuclear	49.92%	$0.0000	$0.0000	$0.0000
Hydro	0.79%	$0.0000	$0.0000	$0.0000
Total (Adder)		**$0.0022**	**$0.0090**	**$0.0269**

For the first scenario, where 100% of the allowances were auctioned, the incremental increase was then added to the average retail rates in 2006 (EIA, Form 826, 2008). According to the index of rate schedules for both utilities, the FAC makes up a fixed amount of rates for each customer class. Therefore, this analysis assumes that the same

[7] The value is the generation mix included in the fuel adjustment charge is different than the average generation mix of the state from the EIA. This is because the 370 MW W.S. Lee Coal Power Plant, 2700 MW Oconee Nuclear Power Plant, and 2326 MW Catawba Nuclear Power Plant all located in South Carolina were included in my analysis

carbon charge was added to the rates regardless of customer class.[8] Table IV shows how this cost of CO_2 would have impacted 2006 retail electricity rates in North Carolina.

These results show that a fully passed through price of $5/ton CO_2 would only raise rates 2% for residential customers, 3% for commercial customers, and 5% for industrial customers. However, at $60/ton, costs may increase by approximately 30% for residential customers, 38% for commercial customers, and up to 52% for industrial customers. The fact that the fuel adjustment charge is fixed for each customer class causes this larger percentage increase for industrial customers. Therefore, because initial industrial rates are lower, the percentage increase for industrial customers is larger than for residential customers. As CO_2 price increases, this effect is magnified.

Table IV: Impact on NC rates by customer class & 100% Auction Scenario

	Fuel Adjustment Adder ($/kWh)	Rate ($/kWh)	Percentage Change
	2006 Residential Retail Rates		
No Carbon		$0.0912	
$5/ton	$0.0022	$0.0934	2.45%
$20/ton	$0.0090	$0.1002	9.82%
$60/ton	$0.0269	$0.1181	29.45%
	2006 Commercial Retail Rate		
No Carbon		$0.0712	
$5/ton	$0.0022	$0.0734	3.14%
$20/ton	$0.0090	$0.0802	12.57%
$60/ton	$0.0269	$0.0981	37.72%
	2006 Industrial Retail Rate		
No Carbon		$0.0512	
$5/ton	$0.0022	$0.0534	4.37%
$20/ton	$0.0090	$0.0602	17.49%
$60/ton	$0.0269	$0.0781	52.46%

[8] Duke Energy Rate Schedule http://www.duke-energy.com/north-carolina/understand/electric-rates.asp
Progress Energy Rate Schedule http://www.progress-energy.com/aboutenergy/rates/nctariffs.asp

Table V shows the results of the same analyses under the second scenario, where it was assumed that only half of the allowances were auctioned and therefore only half of the allowance costs were passed through. It was calculated by dividing the total costs of the policy by one half, meant to represent a situation where the utilities only would recover the monetary expenses incurred for allowances. As stated previously, it was assumed that the NCUC would only allow monetary expenses to be passed through. The results show that the CO_2 adder, and the percentage increase in rates, is half as what it was in the full cost pass through scenario, which is expected. The complete calculation spreadsheets for North Carolina are displayed in Appendix 2.

Table V: Impact on NC rates by customer class & 50% Auction Scenario

	Fuel Adjustment Adder ($/kWh)	Rate ($/kWh)	Percentage Change
2006 Residential Rates			
No Carbon		$0.0912	
$5/ton	$0.0011	$0.0923	1.23%
$20/ton	$0.0045	$0.0957	4.91%
$60/ton	$0.0134	$0.1046	14.73%
2006 Commercial Retail Rate			
No Carbon		$0.0712	
$5/ton	$0.0011	$0.0723	1.57%
$20/ton	$0.0045	$0.0757	6.29%
$60/ton	$0.0134	$0.0846	18.86%
2006 Industrial Retail Rate			
No Carbon		$0.0512	
$5/ton	$0.0011	$0.0523	2.19%
$20/ton	$0.0045	$0.0557	8.74%
$60/ton	$0.0134	$0.0646	26.23%

3. Projected Retail Rate Impacts in New Jersey

3.1 Background and Assumptions

New Jersey's electricity market is deregulated and part of the PJM market. PJM consists of 13 states plus the District of Columbia, making it the largest wholesale power market in the United States. Because of its deregulated market, more than 98% of all electricity produced in the state during 2006 came from independent power producers, also defined as merchant generators. Merchant generators produce power that is sold into the wholesale market. It is in this market where electricity is purchased by local distribution companies (LDC) and sold to retail consumers. New Jersey regulators set the retail prices that LDCs charge, but have no control over the wholesale price. The electricity generation mix in 2006 consisted of nuclear power making up approximately 54% of all power generated in the state. Natural gas generated 26%, coal generated 18%, and non-hydro renewable generation sources also made up 1.5%. However, because wholesale price of electricity is set by the marginal generator, generation mix will not have an impact on retail prices in the state.

New Jersey is also one of the ten states that will be participating in RGGI. It has already committed that 100% of its allowances will be auctioned when the program commences in 2009. Since it is a deregulated market, any increase due to CO_2 will manifest itself in the incremental increase in the cost to generate electricity from the marginal fuel. In New Jersey this fuel is assumed to be natural gas during peak hours and coal during off peak hours (New Jersey Energy Master Plan, 2008). Since prices will be determined in the wholesale market, the New Jersey Board of Public Utilities (NJBPU) will not have direct control over how the costs are passed through, because the incremental increase in the price electricity will be set beyond their jurisdiction. Therefore, the BPU approves the rates that the local distribution companies charge retail customers downstream of the wholesale market, but they do not have the authority to regulate wholesale prices that the LDCs must pay.

The revenue from the allowance auctions is intended to be directed towards projects that promote energy efficiency and develop low carbon energy technology in the state. Specifically 20% of all revenues will be allocated to the NJBPU. They are required to use this revenue fund programs designed to reduce electricity demand and mitigate any impact on low-income to moderate-income residential ratepayers. The New Jersey State Legislature has mandated that any program receiving funding from auction revenue "result in a measurable reduction in energy demand" (NJ Assembly, 2008). This might rule out any direct credits to ratepayers, but over the long run, rate impacts from RGGI might be mitigated by energy efficiency policy. CO_2 prices are expected to be modest at the program's onset. In the advent that allowance prices exceed $7/ton, the state is required to hold a second auction, and the NJBPU would be required to develop an "action plan" for ratepayer relief.

3.2 Data Collection

Unlike North Carolina, generators are not required to file for a fuel adjustment charge, so plant specific generation data was not available. Therefore, generation data was taken from the EIA's "State Electricity Profile" for New Jersey. The most recent generation data available was from 2006. The data available from EIA showed annual generation electricity generated in the state by fuel. Despite the fact that individual plant level data was not available, the available information was enough to complete the analysis.

3.3 Methodology and Analysis

The incremental increase in the price of electricity for each fuel was the same as the Table II results calculated in section 1.3. However, inn a wholesale market, such as PJM, the cost of electricity is determined by the cost of the last mega-watt hour generated, which is different from North Carolina, where the variable cost was set by an average of the cost of production for all the generating facilities serving the state. The New Jersey market is also an open to generators throughout the PJM region. As shown in the data collection section, even if the state were to consume of its electricity generated in state, it would still need to import almost an additional 25% more to meet demand.

In order to calculate the contribution of fuel to electricity prices when electricity is priced on the margin, I assumed that there were 3 different types of marginal generating units in a given day for the PJM region. I defined them as peak, intermediate, and off-peak. The 8 hours of the day where demand was highest I defined as peak, the 8 hours of the day where demand was lowest I defined as off-peak, and the 8 hours where the demand was in the middle was defined as intermediate. It should be noted that these designations were set specifically for this analysis. During off-peak hours, I assumed that the marginal fuel was coal. I assumed that during intermediate hours the marginal source of generation was combined cycle natural gas plants and during peak hours the marginal sources were non-combined cycle natural gas plants. Because these facilities both use natural gas, I assumed that natural gas was the marginal fuel for two thirds of the day (PJM State of the Market, 2007). Despite the fact that nuclear power made up for over 50% of the state’s generation mix, I assumed it did not operate on the margin at any time. In order to get an approximate CO2 adder, I took the weighted average of the incremental increase for natural gas (peak & intermediate) and coal (off-peak).

The results for a \$5/ton, \$20/ton, and \$60/ton price of CO_2 are shown in Table VI. The complete calculation spreadsheets are displayed in Appendix III. They show that the percentage impact on retail rates for all three customer classes is similar to that of North Carolina. The percentage increase in rates due to allowance charges is relatively low at \$5/ton, and grows significantly as the price of CO_2 rises. The percentage increase in price due to a carbon charge was slightly lower in New Jersey than in North Carolina. This is most likely due to the fact that initial rates in North Carolina are lower than in New Jersey. It should also be noted that overall retail prices were still much higher in New Jersey than in North Carolina, in all three CO_2 price scenarios. The complete results for the New Jersey analysis are displayed in Appendix 3.

Because I assumed that all allowances were allocated to generators, the wholesale price would embed the cost of CO2 regardless of how the allowances were allocated. Therefore, the results in Table VI represent both the 100% and 50% auction scenario. At a higher CO_2 price, the increase in rates is substantial, especially for industrial customers. In a state with already higher than average electricity rates, this is an important concern to for policymakers. In order to mitigate this impact, 60% of auction revenues are designated to the New Jersey Economic Development Authority in order to provide financial assistance for commercial and industrial customers to support and develop end use energy efficiency projects (NJ Assembly, 2008).

Table VI: Impact on NJ rates by customer class in a 100% Auction or a 50% Auction Scenario			
	Fuel Adjustment Adder ($/kWh)	Rate ($/kWh)	Percentage Change
2006 Residential Rates			
No Carbon		$0.1689	
$5/ton	$0.0032	$0.1721	1.90%
$20/ton	$0.0129	$0.1818	7.61%
$60/ton	$0.0386	$0.2075	22.84%
No Carbon		$0.1551	
$5/ton	$0.0032	$0.1583	2.07%
$20/ton	$0.0129	$0.1680	8.29%
$60/ton	$0.0386	$0.1937	24.88%
2006 Industrial Retail Rate			
No Carbon		$0.0931	
$5/ton	$0.0032	$0.0963	3.45%
$20/ton	$0.0129	$0.1060	13.81%
$60/ton	$0.0386	$0.1317	41.44%

4. Projected Retail Rate Impacts in Washington State

4.1 Background and Assumptions

The final state examined was Washington State. Washington is unique in that it has extensive hydro-electric resources, used to generate over 75% of its electricity. Coal makes up only 5.9% of the generation mix, and natural gas comprises only 6.9%. Therefore, the degree to which a carbon price might impact retail rates is smaller than in states where fossil fuels make up a larger share of generation. For instance the fuel adjusted component for Washington's largest utility is approximately $0.003 (Puget Sound Electric Company, 2008), compared to a $0.017 adjustment in North Carolina. This is a function of the low utilization of coal in the state, and the fact that the delivered price of coal in the Pacific Northwest is lower than in North Carolina. Washington is a regulated state, with approximately 85% of electricity generated by vertically integrated utilities. It is a member of the Western Climate Initiative (WCI), an agreement modeled after RGGI, consisting of 7 Western U.S. states and two Canadian Provinces. However, WCI is still in the developmental stage, and specific policies have not yet been defined.

4.2 Data Collection

Generation and price data were both taken from the EIA state electricity profile. This is the same source as New Jersey data.

4.3 Methodology and Analysis

The incremental cost of generation due to a CO_2 price was the same as in North Carolina and New Jersey, shown in Table II. Because Washington is a regulated state, the same process for calculating rates in North Carolina was used. The incremental cost was multiplied by the share of generation for each fuel and summed to give the total fuel adjustment cost. The impact of CO_2 prices assuming the ratepayers bear 100% of the cost is shown in Table VII.

These results show that Washington ratepayers will be less affected by a price on CO_2 than those in North Carolina or New Jersey. Even at a relatively high cost of $60/ton CO2, residential ratepayers would only see a 13% increase in rates. As shown in Table VIII the results for the 50% auction scenario is half of full auction. From these results it can be concluded that given the states low carbon intensive generation asset base, Washington State ratepayers do not stand to be significantly impacted by climate change policy. The complete calculation spreadsheets are displayed in Appendix 4.

Table VII: Impact on Washington State rates by customer class in a 100% Auction Scenario			
	Fuel Adjustment Adder ($/kWh)	**Rate ($/kWh)**	**Percentage Change**
2006 Residential Rates			
No Carbon		$0.0682	
$5/ton	$0.0003	$0.0685	0.40%
$20/ton	$0.0018	$0.0700	2.67%
$60/ton	$0.0091	$0.0773	13.33%
2006 Commercial Retail Rate			
No Carbon		$0.0663	
$5/ton	$0.0003	$0.0666	0.41%
$20/ton	$0.0018	$0.0681	2.74%
$60/ton	$0.0091	$0.0754	13.71%
2006 Industrial Retail Rate			
No Carbon		$0.0444	
$5/ton	$0.0003	$0.0447	0.62%
$20/ton	$0.0018	$0.0462	4.09%
$60/ton	$0.0091	$0.0535	20.47%

Table VIII: Impact on Washington State rates by customer class in a 50% Auction Scenario			
	Fuel Adjustment Adder ($/kWh)	**Rate ($/kWh)**	**Percentage Change**
2006 Residential Rates			
No Carbon		$0.06820	
$5/ton	$0.00015	$0.06835	0.22%
$20/ton	$0.00090	$0.06910	1.32%
$60/ton	$0.00455	$0.07275	6.67%
2006 Commercial Retail Rate			
No Carbon		$0.07	
$5/ton	$0.00015	$0.06645	0.23%
$20/ton	$0.00090	$0.06720	1.36%
$60/ton	$0.00455	$0.07085	6.86%
2006 Industrial Retail Rate			
No Carbon		$0.04	
$5/ton	$0.00015	$0.04455	0.34%
$20/ton	$0.00090	$0.04530	2.03%
$60/ton	$0.00455	$0.04895	10.25%

5. Summary and discussion of results

5.1 Discussion of results

In North Carolina and Washington State, allowance allocation method was assumed to be the determining factor of how allowance prices were reflected in retail rates. As stated earlier, the key assumption in the analyses was that PUCs only allowed monetary expenses to be passed on to retail rates. This was not the case in state's operating in a wholesale market such as New Jersey, where I assume that the wholesale electricity price would include the opportunity cost of allowances. Therefore, in a wholesale market, the differences in allowance allocation methods would not to have an impact on rates. Given these assumptions, consumers in states with operating wholesale markets might bear larger costs from climate policy than those in traditionally regulated states. An exception to this would be if allowances were allocated downstream to local distribution companies. This places them under the jurisdiction of PUCs, who could then determine whether or not to mitigate rate increases. Lieberman-Warner actually specifies that 10% of allowances are allocated to such entities. This is an attempt to prevent ratepayers in deregulated states from bearing a larger cost than those in regulated states.

Electricity price in North Carolina and Washington State is determined by the average cost of generation. This means that the state's portfolio of generation assets play a major role in determining retail rates. It will also mean that states with carbon intensive portfolios, such as North Carolina, could face potentially significant increases in rates in the presence of a CO_2 price. In New Jersey the marginal cost of generation sets prices. Therefore, the average generation mix does not directly affect price. In New Jersey, nuclear power makes up over 50% of all generation, but because it is not the marginal fuel it does not determine the wholesale price. Even though coal makes up only 17% of the state's generation mix, it is the marginal fuel one third of the time, and it will impact average wholesale electricity price, while nuclear will not. Due to the fact that the carbon intensity of the marginal sources of generation is higher than the average generation mix, the CO_2 adder for New Jersey would have been lower if rates in the state were set through average cost pricing.

In addition, PJM is an interstate market, so electricity may flow freely across state boundaries. This is different from Washington and North Carolina where rates are based off of generation almost exclusively in the state. It should be noted that in-state generation mix does matter because wholesale market prices are partly a function of location. In other words if a power plant is located adjacent to a load center, the least cost option for that load center might be electricity from the nearby power plant. This method of pricing, known as locational marginal pricing (LMP), is what sets wholesale prices, and may, holding other variables constant, favor the purchase of in-state generation. However, any such analysis to quantity the exact amount would require a more advanced wholesale power modeling that is beyond the scope of this paper.

5.2 Fuel Switching Analysis

The assumption of no fuel switching is key limitation in the analysis that may not hold true even in the short term. For instance, a high enough CO_2 price may make generation from coal more expensive than generation from natural gas. In order to estimate this price, I assumed coal prices of $70 per ton of coal, $2.00 per gallon of fuel oil, and a natural gas price of $8 per mmBTU. These prices were consistent with 2006 data for North Carolina and New Jersey. This resulted in an approximate $0.03/kWh cost to generate electricity from coal and a $0.07/kWh to generate from natural gas. Under these prices, it would take a CO_2 price of approximately $96.50/ton for the cost of generation from natural gas to equal coal. This calculation is shown in Table IX.

Table IX: CO_2 price at which Coal & Natural Gas break even

	Emissions Factor (lbs/MWh)	Fuel Price	CO2 Price	Incremental Increase in CO2 price ($/ton)	Incremental Increase in CO2 price ($/kWh)	Price of Generation w/o CO2 ($/kWh)	Total Increase in price ($/kWh)
Coal (Short Tons)	2026	$70.00	$96.50	$88.706	$0.089	$0.030	$0.119
Natural Gas (mmBTU)	1113	$8.00	$96.50	$48.732	$0.049	$0.070	$0.119
Petroleum ($/gal)	1821	$2.00	$96.50	$79.731	$0.080	$0.120	$0.200

Given the current political climate in the United States, an allowance price approaching $100/ton is unlikely. Therefore, fuel switching from coal to natural gas is not likely in the near term due to CO_2 price. However, if coal prices rise higher relative to natural gas, than the CO_2 price where this type of fuel switching occurs may change. Other types of fuel switching may occur if a state has excess hydro-electric capacity and it uses that to displace a fossil generating source. All nuclear facilities in the analysis were running at approximately full capacity in 2006, therefore no further fuel switching from a fossil source to nuclear power would be possible.

In the long term, a price on CO_2 might not significantly impact the generation mix given the current fleet of power plants, but might significantly alter the investment decisions of the electric power industry. Less carbon intensive sources of generation such as nuclear power, coal with carbon capture and storage, wind power, and solar power may become more economically viable investments at a high enough price of carbon. Another prospect is an increased focus on energy efficiency. Some recent studies of utility behavior have shown that the prospect of a CO_2 price has lead utilities in the Western United State's focus on energy efficiency investments (Barbose, Wiser, Phadke, and Goldman, 2008). As mentioned in Part A, energy efficiency is a key strategy by policymakers in RGGI states in their plan to reduce emissions while maintaining a healthy regional economy.

5.3 Windfall Profits for New Jersey Generators

At the onset of the European Union's Emissions Trading System, generators in wholesale power markets saw extensive windfall profits. They occurred because the price of electricity went up, in a large part due to the price on CO_2. However, the cost to generate electricity did not increase at the same rate, because allowances were allocated to generators for free. Therefore, generators were getting more revenue from selling electricity, while their costs did not increase at the same rate. In this section, I attempt to identify any windfall profits (or losses) that generators in New Jersey may realize from a CO_2 price.

I selected New Jersey, because it is the only one of the three states that I analyzed with a wholesale power market. Vertically integrated utilities in regulated states, such as North Carolina and Washington State, would not be able to obtain any monetary windfall profits due to the regulatory structure. This is because the rates are determined by average cost instead of the marginal cost pricing. The average increase in costs across all generating sources can be recovered through rates, but nothing additional can be recovered. It should be noted that free allocation would produce an economic windfall for utilities in regulated states, but my analysis only considers financial windfall. Therefore, the New Jersey will be the one state examined.

I assumed a $5/ton CO_2 price. This is consistent with current expectations of RGGI allowance prices in the near term. I used same set of assumptions used in my retail rate impact analysis for New Jersey to calculate the total expenses borne for each fuel due to a CO_2 price. Using the CO_2 adder for New Jersey determined in Section 3, I was able to calculate the increase in revenue for each type of fuel by multiplying the adder by amount generated from each. I then calculated the net gain or loss for each fuel by subtracting the revenues from the expenses. The results are shown below in Table IX.

Table X: Potential financial impact of CO2 price on New Jersey Generators

	Statewide CO2 Adder ($/MWh)	2006 Generation (MWh)	Increased Revenue	CO2 Expense	Net Gain (Loss)
Coal	$3.20	10,861,873	$ 34,757,994	$ 45,929,361	**$ (11,171,367)**
Petroleum	$3.20	277,228	$ 887,130	$ 945,988	**$ (58,858)**
Natural Gas	$3.20	15,637,622	$ 50,040,390	$ 19,900,080	**$ 30,140,310**
Nuclear	$3.20	32,567,885	$ 104,217,232	$ -	**$ 104,217,232**
Hydroelectric	$3.20	35,436	$ 113,395	$ -	**$ 113,395**
Other Renewables	$3.20	916,783	$ 2,933,706	$ -	**$ 2,933,706**

The results show that in 2006 nuclear power generation facilities in New Jersey would have generated over $104 million worth of windfall profits if there were a $5/ton price. Natural gas, hydro-electric, and renewable energy generation facilities would also have booked a net gain due to a CO_2 allowance price. Coal and petroleum facilities both suffer a net loss. Petroleum has a relatively small loss of $58,858, while coal’s is much more significant at $11,171,367. These results represent the all the generators in the state, and is not divided at the firm level. However, it can be inferred that merchant generators who own nuclear assets in New Jersey stand to increase their profits in the case of a CO_2 charge. The opposite can be said for firms whose portfolio consists heavily of coal generators. Over the long term, this increase expense may make coal fired power plants a less attractive long term investment. If policymakers are concerned with offsetting this loss to coal plants over the short term, they could design plans to allocate a certain percentage of allowances directly to coal plants for free. However, it should be noted that this strategy would defeat part of the purpose of a cap and trade system, which is to discourage carbon intensive production by increase its cost.

5.4 Areas for potential future study

CO_2 cost pass through in the electricity sector will be an important element of any climate policy. From the public's perspective how allowance costs are represented in a consumer's monthly electricity bill could have a significant effect on their energy usage and overall budget. This has implication both economically and politically, because politicians may be wary of endorsing a policy that raises the expenses of their constituency. Further analysis on how these rate increases could potentially impact regional economies in terms of job loss and gain could expand upon this issue. At the firm level, how costs are passed through will be a key determinant to cost recovery. Therefore, individual company level analysis, used to determine how cost pass-through scenarios might impact their profit margins, would be useful to the firms and state regulators. My analysis assumed demand and fuel prices of 2006. It does not take into account how the current state of the electric power industry will evolve into the future. This may be directly due to climate policy, or be the result of other factors such as higher fuel prices, plant retirements, regulatory reform, or technological development. Studies on how the electric power industry could potentially interact with climate policy are valuable tools for policymakers, regulators, or industry executives looking into the future.

Estimating the retail rate impacts of changes in the generation mix and the development of new technologies is another natural extension of my analysis. New technologies could potentially mitigate any rate increase due to CO_2 emissions in a carbon constrained economy. However, capital intensive investments such as nuclear power or carbon sequestration and storage projects will likely raise rates. In regulated states, capital investments for these projects could also qualify to be placed in the rate base, where utilities could earn a return. Determining whether or not the emissions saved from a new nuclear plant or IGCC plant will result in a higher or lower impact on ratepayers than simply purchasing CO_2 permits would be a helpful project for utility commissioners considering adding a project into the rate base. North Carolina, New Jersey, and Washington State all have Renewable Portfolio Standards (RPS). The impact of state RPS' on retail rates can also be further examined.

Energy efficiency is being seen by New Jersey and other RGGI states as an important element in implementing climate policy. Examining the impacts of different energy efficiency goals by state on rates would be another helpful project for state policymakers. Modeling how decreases in demand might change the dispatch order, and resulting generation mix or marginal fuel, would also be of interest. The relationship between CO2 price and natural gas price is also a relationship that could be further explored. Since carbon regulation has not officially begun in the United States, most analysis that can be done is ex-ante. Once policies have been enacted, it will be possible to analyze actual impacts, which will present a significant amount of policy evaluation research opportunities.

5.5 Conclusions

The analysis of these three states indicates that a CO2 price will raise retail electricity rates differently by state. Electric consumers in state's powered primarily by coal will likely see a higher rates than those in state's such as Washington, where fossil fuels make up a relatively small percentage of the generation mix. However, in states with already high retail rates, such as New Jersey, any further increases could prove very unpopular and have negative effect on the state's economy. Balancing the interest of states with diverse electricity market profiles, such as the three just examined, is a challenge for national policymakers. The increase in costs when full pass through is assumed is found to be significant. However, investment in energy efficiency projects and new generation technology may lower this cost over the long term and achieve the goal of reducing CO_2 emissions.

The actual cost of the CO_2 allowances in the advent of a cap and trade system will also have a major impact on the eventual retail rate increases. Cost containment will be a major element of any cap and trade program implemented in the United States. As mentioned earlier in the paper, Lieberman-Warner (S.2191) calls for the establishment of the Carbon Market Efficiency Board (CMEB). It is designed to serve as an independent overseer of the market for allowances. One if it's stated functions would be to stabilize the price of allowances so they do not result in any significant economic damage. Because of electricity's ubiquitous nature in the economy, significant rate increases from a CO_2 price could be an important factor in any action taken by an entity such as the CMEB.

Whatever the actual cost of CO_2, the issues of cost pass-through and retail electricity rates presents important trade-offs between economic efficiency and minimizing impacts to consumers. From a purely economic efficiency standpoint, climate policy will be most cost effective if ratepayers bear the full cost of CO_2. Theoretically, this would trigger behavioral responses consistent with the price that would encourage maximum investment in low carbon technology and improved efficiency technologies. However, there are concerns that such a policy may unfairly burden lower income ratepayers, who tend to spend a greater percentage of their earnings on electricity, and cause greater damage to the overall economy. From an environmental perspective, if a cap is met, it does not matter if it was achieved through full cost pass through or less. Placed in a political context, a program with less direct consumer impact might be more likely to be enacted. Ultimately, trade-offs between the economic efficiency, social equity, environmental integrity, and political feasibility all represent the challenges associated with designing fair yet effective climate policy.

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Appendix A: Unit Conversion Assumptions

1- CO_2 Emissions (lbs) = CO_2 Emissions Factor(lbs/MWh) * Generation (MWh)

2- Metric Tons (CO_2) = lbs of CO_2/2204[9]

3- Fuel adjustment for coal ($/kWh)[10] =

$$\frac{\text{Short ton of coal (\$/ton)}}{\text{(21896.63 MJ) * (0.27778 kWh/1 MJ)*(40\% Boiler Efficiency)}}$$

4- Fuel adjustment for natural gas ($/kWh)[2] =

$$\frac{\text{mmBTU of natural gas (\$/mmBTU)}}{\text{(1047.53 MJ) * (0.27778 kWh/1 MJ)*(42\% Turbine Efficiency)}}$$

5- Fuel adjustment for petroleum ($/kWh)[2] =

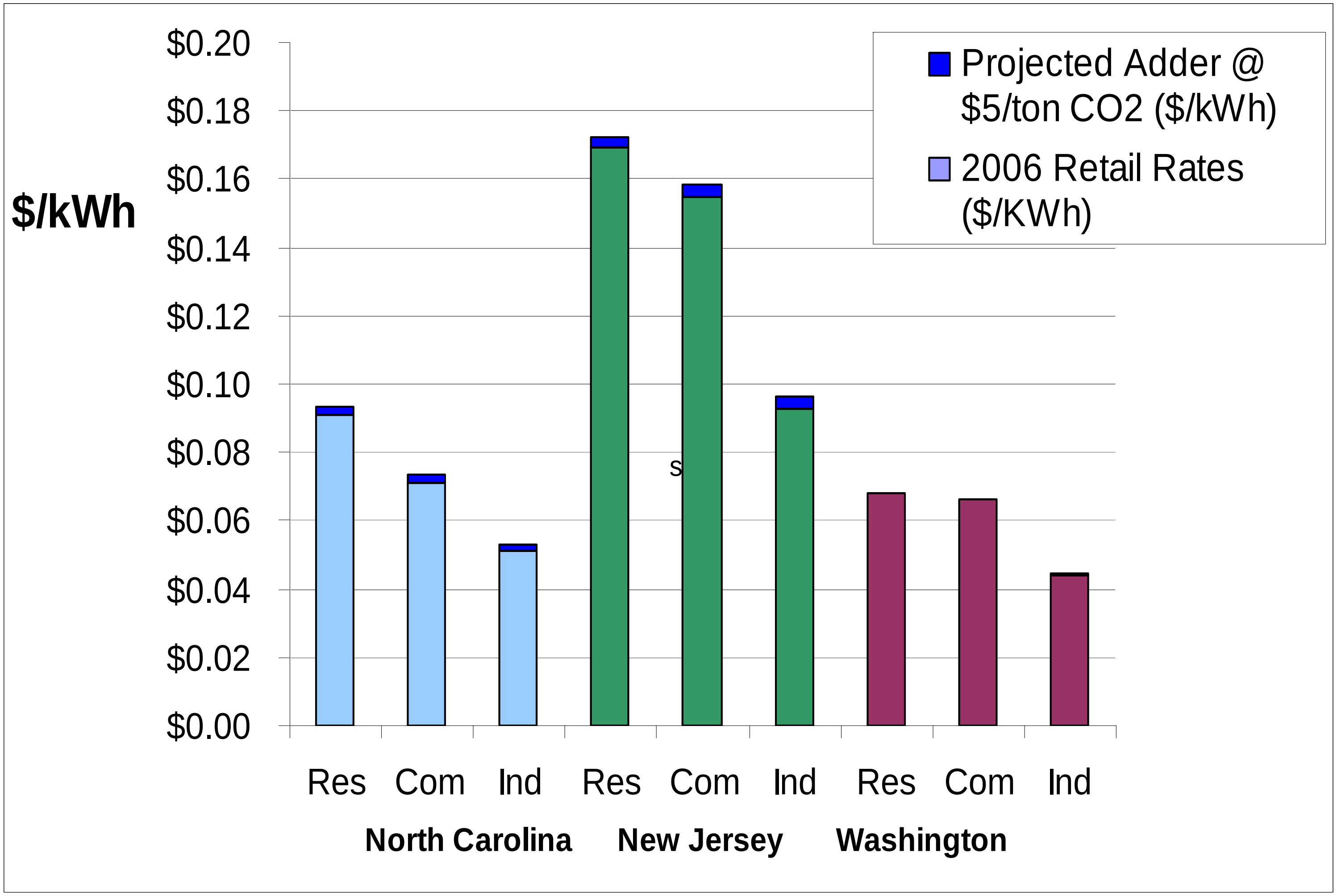
$$\frac{\text{Gallon of \#2 Fuel Oil (\$/gallon)}}{\text{(1047.53 MJ) * (0.27778 kWh/1 MJ)*(40\% Generator Efficiency)}}$$

6- $\$/\text{kWh} = \frac{\$/\text{MWh}}{1000}$

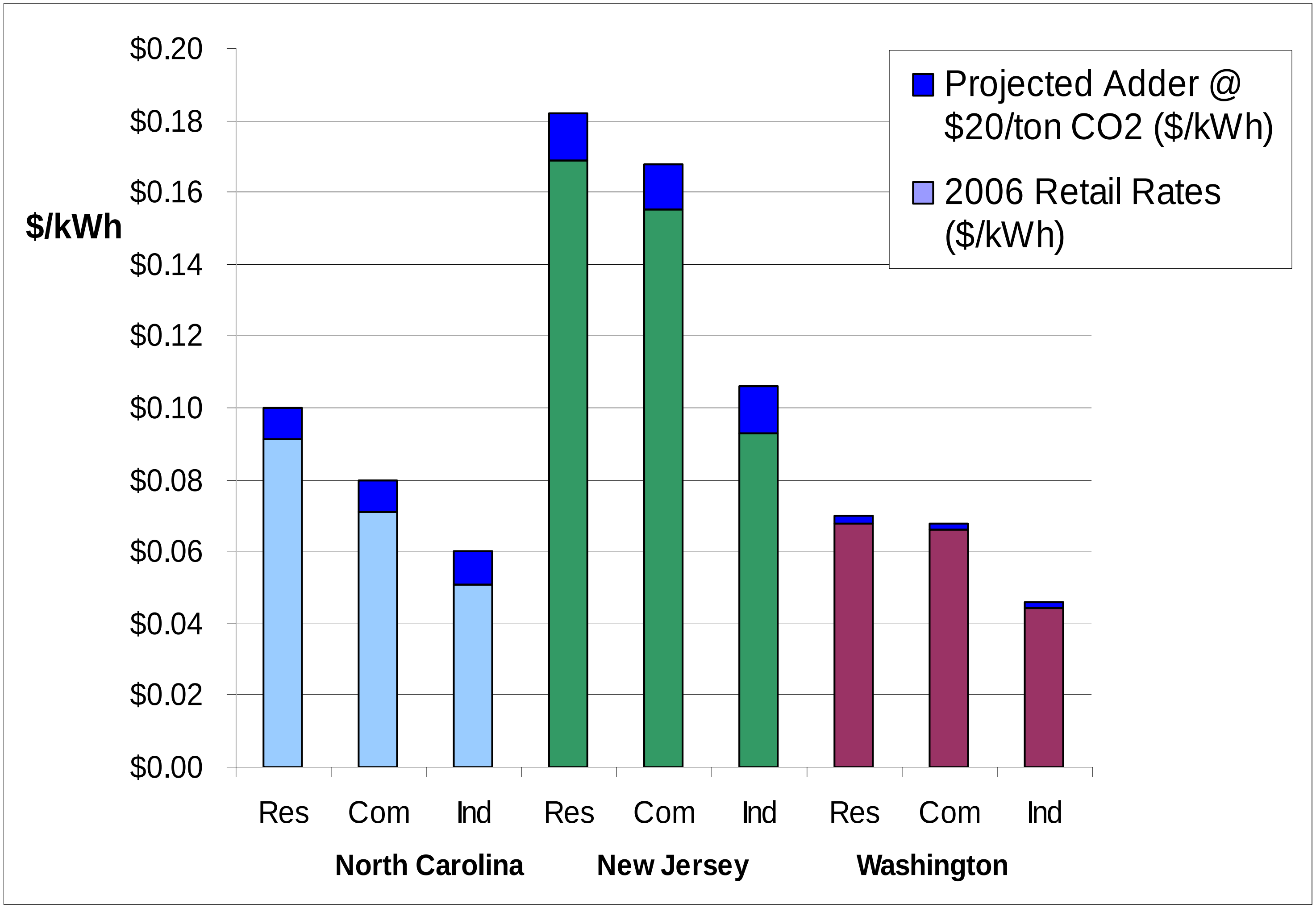
[9] lbs to short tons http://www.metric-conversions.org/weight/tonne-conversion.htm
[10] EIA Energy Conversion Calculator http://www.eia.doe.gov/kids/energyfacts/science/energy_calculator.html

Appendix B: Graphical results; Increase in retail rates by state

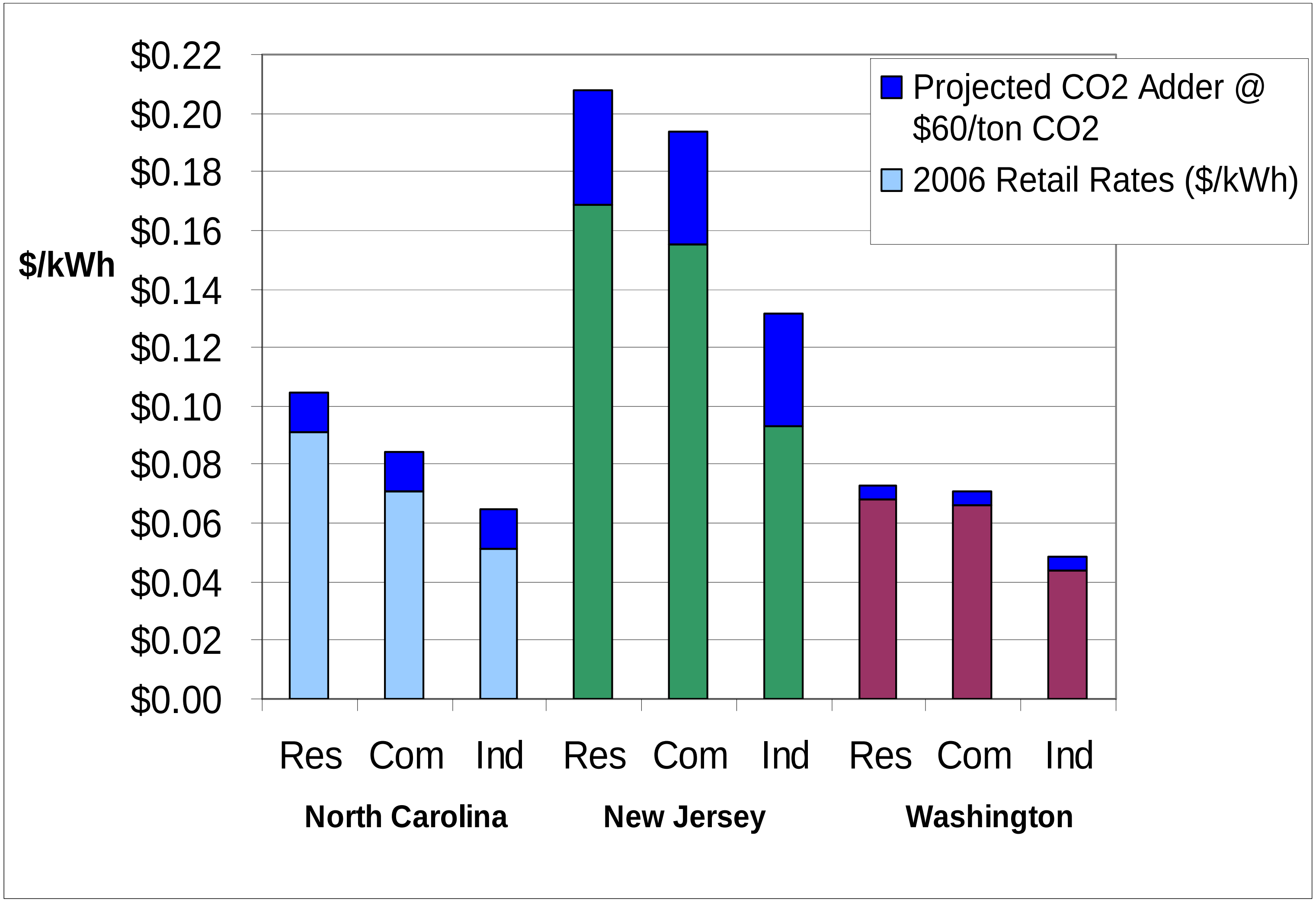
Appendix B-Figure 1: $5/ton & 100% auction



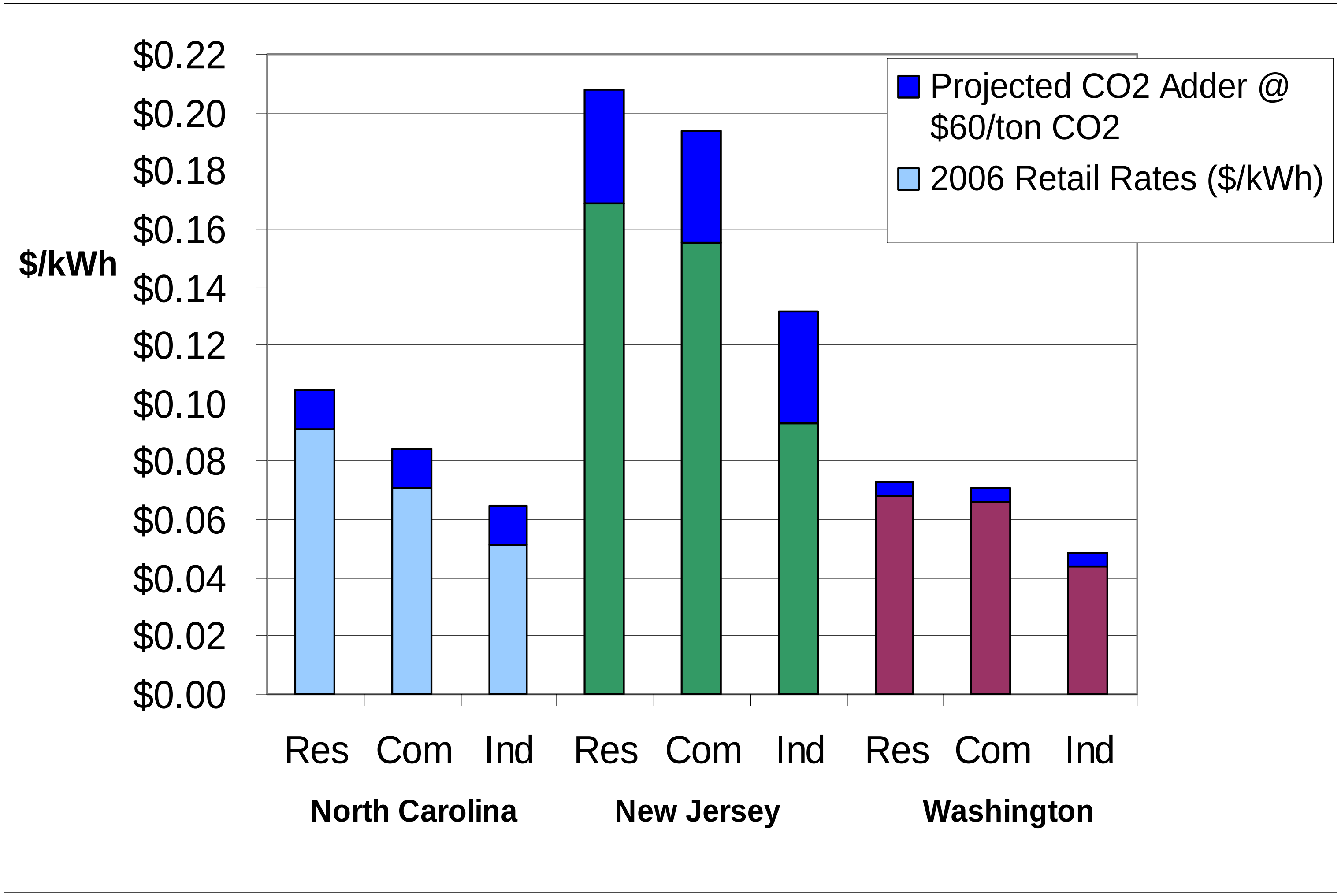
Appendix B-Figure 2: $20/ton & 100% auction



Appendix B-Figure 3: $60/ton & 100% auction



Appendix B-Figure 4: $60/ton & 50% auction



Appendix C: North Carolina Spreadsheets

Appendix C-Table I: Full Cost Pass through Calculations

	Incremental $/MWh Increase					Fuel Adustment Factor for 2007-08				
	No Carbon	$5/ton	$20/ton	$60/ton			FAC	Customers	Weighted Avg	
Coal		$4.60	$18.38	$55.15		Duke Energy	$0.0178	55%	$0.0098	
Natural Gas		$2.52	$10.10	$30.30		Progress Energy	$0.0105	36%	$0.0038	
Petroleum		$4.13	$16.52	$49.57					**$0.0136**	
						Incremental increase from full cost pass through				
							Generation Mix	Adjusted $5/ton Incremental Increase	Adjusted $20/ton Incremental Increase	Adjusted $60/ton Incremental Increase
	Incremental $/kWh Increase					**Coal**	47.94%	$0.0022	$0.0088	$0.0264
	No Carbon	$5/ton	$20/ton	$60/ton		**Natural Gas**	1.31%	$0.0000	$0.0001	$0.0004
Coal		$0.0046	$0.0184	$0.0552		**Petroleum**	0.04%	$0.0000	$0.0000	$0.0000
Natural Gas		$0.0025	$0.0101	$0.0303		**Nuclear**	49.92%	$0.0000	$0.0000	$0.0000
Petroleum		$0.0041	$0.0165	$0.0496		**Hydro**	0.79%	$0.0000	$0.0000	$0.0000
						Total		**$0.0022**	**$0.0090**	**$0.0269**
Full cost pass through scenario										
	Gen Mix	No Carbon	Adjusted No Carbon	Adjusted $5/ton Incremental Increase	Adjusted $5/ton Carbon	Adjusted $20/ton Incremental Increase	Adjusted $20/ton Carbon	Adjusted $60/ton Incremental Increase	Adjusted $60/ton Carbon	
Coal	47.94%	$0.0301	$0.0144	$0.0022	$0.0167	$0.0088	$0.0233	$0.0264	$0.0409	
Natural Gas	1.31%	$0.0693	$0.0009	$0.0000	$0.0009	$0.0001	$0.0010	$0.0004	$0.0013	
Petroleum	0.04%	$0.1061	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	$0.0001	
Nuclear	49.92%	$0.0004	$0.0002	$0.0000	$0.0002	$0.0000	$0.0002	$0.0000	$0.0002	
Hydro	0.79%	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Total			**$0.0156**	**$0.0022**	**$0.0178**	**$0.0090**	**$0.0246**	**$0.0269**	**$0.0425**	

Appendix C: North Carolina Spreadsheets

Appendix C-Table II: Half Cost Pass through calculations

Incremental $/MWh Increase	No Carbon	$5/ton	$20/ton	$60/ton
Coal		$2.30	$9.19	$27.58
Natural Gas		$1.26	$5.05	$15.15
Petroleum		$2.07	$8.26	$24.79

Fuel Adustment Factor for 2007-08	FAC	Customers	Weighted Avg
Duke Energy	$0.0178	55%	$0.0098
Progress Energy	$0.0105	36%	$0.0038
			$0.0136

Incremental $/kWh Increase	No Carbon	$5/ton	$20/ton	$60/ton
Coal		$0.0023	$0.0092	$0.0276
Natural Gas		$0.0013	$0.0050	$0.0151
Petroleum		$0.0021	$0.0083	$0.0248

Incremental increase from half cost pass through	Generation Mix	Adjusted $5/ton Incremental Increase	Adjusted $20/ton Incremental Increase	Adjusted $60/ton Incremental Increase
Coal	47.94%	$0.0022	$0.0088	$0.0264
Natural Gas	1.31%	$0.0000	$0.0001	$0.0004
Petroleum	0.04%	$0.0000	$0.0000	$0.0000
Nuclear	49.92%	$0.0000	$0.0000	$0.0000
Hydro	0.79%	$0.0000	$0.0000	$0.0000
Total		**$0.0022**	**$0.0090**	**$0.0269**

Half cost pass through scenario

	Gen Mix	No Carbon	Adjusted No Carbon	Adjusted $5/ton Incremental Increase	Adjusted $5/ton Carbon	Adjusted $20/ton Incremental Increase	Adjusted $20/ton Carbon	Adjusted $60/ton Incremental Increase	Adjusted $60/ton Carbon
Coal	47.94%	$0.0301	$0.0144	$0.0011	$0.0156	$0.0044	$0.0189	$0.0132	$0.0277
Natural Gas	1.31%	$0.0693	$0.0009	$0.0000	$0.0009	$0.0001	$0.0010	$0.0002	$0.0011
Petroleum	0.04%	$0.1061	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	$0.0001
Nuclear	49.92%	$0.0004	$0.0002	$0.0000	$0.0002	$0.0000	$0.0002	$0.0000	$0.0002
Hydro	0.79%	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total			**$0.0156**	**$0.0011**	**$0.0167**	**$0.0045**	**$0.0201**	**$0.0134**	**$0.0290**

Appendix D: New Jersey Spreadsheets

Appendix D-Table I: CO2 Price Impact

	lbs/kWh									
CO2 Emissions Factor for Coal	2.026									
CO2 Emissions Factor for Natural Gas	1.113									
CO2 Emissions Factor for Fuel Oil	1.821									
Increase Cost of Generation by Fuel	**MWh**	**Unit Fuel Cost**								
Coal	10,861,873	$74.36	$/ton	$0.03						
Petroleum	277,228	$2.24	$/gal	$0.14						
Natural Gas	15,637,622	$8.06	$/mmBTU	$0.07						
Other Gases	130,450									
Nuclear	32,567,885									
Hydroelectric	35,436									
Other Renewables	916,783									
Pumped Storage	-298,601									
Other	571,461									
2006 Generation in NJ	**MWh**	**lbs of CO2**	**Tons of CO2**	**$5/ton**	**$/kWh increment ($5/ton)**	**$5/ton Price**	**$20/ton**	**$/kWh increment ($20/ton)**	**$60/ton**	**$/kWh increment ($60/ton)**
Coal	10,861,873	22,006,154,698	9,984,644	$49,923,218	$0.00	$0.04	$199,692,873.85	$0.02	$599,078,621.54	$0.06
Petroleum	277,228	504,832,188	229,053	$1,145,264	$0.00	$0.14	$4,581,054.34	$0.02	$13,743,163.01	$0.05
Natural Gas	15,637,622	17,404,673,286	7,896,857	$39,484,286	$0.00	$0.07	$157,937,144.16	$0.01	$473,811,432.47	$0.03
Other Gases	130,450									
Nuclear	32,567,885									
Hydroelectric	35,436									
Other Renewables	916,783									
Pumped Storage	-298,601									
Other	571,461									

Appendix D: New Jersey Spreadsheets

Appendix D-Table II: Calculation of Imports					
Generation from Out of State in 2005	**Generation mix PJM 2004**	**NJ Imports**	**Generation in NJ**	**Total Sold in state**	**Generation mix with imports**
		18,980,861	**60,427,277**	**79,313,234**	
Coal	52.10%	9,889,029	10,861,873	20,750,902	26.16%
Petroleum	1.10%	208,789	277,228	486,017	0.61%
Natural Gas	7.00%	1,328,660	15,637,622	16,966,282	21.39%
Other Gases		0	130,450	130,450	0.16%
Nuclear	36.90%	7,003,938	32,567,885	39,571,823	49.89%
Hydroelectric	2.30%	436,560	35,436	471,996	0.60%
Other Renewables	0.10%	18,981	916,783	935,764	1.18%

Appendix D-Table III: 2006 Electricity consumed including imports										
	MWh	**lbs of CO2**	**Tons of CO2**	**$5/ton**	**$/kWh increment ($5/ton)**	**$5/ton Price**	**$20/ton**	**$/kWh increment ($20/ton)**	**$60/ton**	**$/kWh increment ($60/ton)**
Coal	20,750,902	42,041,326,603	19,075,012	$ 95,375,060	$0.0046	$0.0046	$381,500,241.41	$0.0184	$1,144,500,724.22	$0.0552
Petroleum	486,017	885,037,815	401,560	$ 2,007,799	$0.0041	$0.0041	$8,031,196.14	$0.0165	$24,093,588.42	$0.0496
Natural Gas	16,966,282	18,883,472,167	8,567,819	$ 42,839,093	$0.0025	$0.0025	$171,356,371.75	$0.0101	$514,069,115.24	$0.0303
Other Gases	130,450									
Nuclear	39,571,823									
Hydroelectric	471,996									
Other Renewables	935,764									
Pumped Storage	-298,601									
Other	571,461									

Appendix D: New Jersey Spreadsheets

Appendix D-Table IV: Off peak and on peak increase electricity price													
Peak & Intermediate Marginal Increase (Natural Gas)					Off Peak Marginal Increase (Coal)					Peak/Off Peak Average Marginal Increase			
	Fuel Adjustment Adder	Rate ($/kWh)				Fuel Adjustment Adder	Rate ($/kWh)				Fuel Adjustment Adder	Rate ($/kWh)	
2006 Residential Rates					2006 Residential Rates					2006 Residential Rates			
No Carbon		$0.1689			**No Carbon**		$0.1689			**No Carbon**		$0.1689	
$5/ton	$0.0025	$0.1714	1.49%		**$5/ton**	$0.0046	$0.1735	2.72%		**$5/ton**	$0.0032	$0.1721	1.90%
$20/ton	$0.0101	$0.1790	5.98%		**$20/ton**	$0.0184	$0.1873	10.88%		**$20/ton**	$0.0129	$0.1818	7.61%
$60/ton	$0.0303	$0.1992	17.94%		**$60/ton**	$0.0552	$0.2241	32.65%		**$60/ton**	$0.0386	$0.2075	22.84%
2006 Commercial Retail Rate					2006 Commercial Retail Rate					2006 Commercial Retail Rate			
No Carbon		$0.1551			**No Carbon**		$0.1551			**No Carbon**		$0.1551	
$5/ton	$0.0025	$0.1576	1.63%		**$5/ton**	$0.0046	$0.1597	2.96%		**$5/ton**	$0.0032	$0.1583	2.07%
$20/ton	$0.0101	$0.1652	6.51%		**$20/ton**	$0.0184	$0.1735	11.85%		**$20/ton**	$0.0129	$0.1680	8.29%
$60/ton	$0.0303	$0.1854	19.54%		**$60/ton**	$0.0552	$0.2103	35.56%		**$60/ton**	$0.0386	$0.1937	24.88%
2006 Industrial Retail Rate					2006 Industrial Retail Rate					2006 Industrial Retail Rate			
No Carbon		$0.0931			**No Carbon**		$0.0931			**No Carbon**		$0.0931	
$5/ton	$0.0025	$0.0956	2.71%		**$5/ton**	$0.0046	$0.0977	4.94%		**$5/ton**	$0.0032	$0.0963	3.45%
$20/ton	$0.0101	$0.1032	10.85%		**$20/ton**	$0.0184	$0.1115	19.75%		**$20/ton**	$0.0129	$0.1060	13.81%
$60/ton	$0.0303	$0.1234	32.55%		**$60/ton**	$0.0552	$0.1483	59.24%		**$60/ton**	$0.0386	$0.1317	41.44%

Appendix E: Washington State Spreadsheets

Appendix E-Table I CO2 Price Impact										
	lbs/kWh									
CO2 Emissions Factor for Coal	2.026									
CO2 Emissions Factor for Natural Gas	1.113									
CO2 Emissions Factor for Fuel Oil	1.821									
Increase Cost of Generation by Fuel	**MWh**	**Unit Fuel Cost**								
Coal		$21.62	$/ton	$0.01						
Petroleum		$2.26	$/gal	$0.14						
Natural Gas		$5.81	$/mmBTU	$0.05						
Other Gases										
Nuclear		$18.61	$/lb U3O8	$0.00						
Hydroelectric										
Other Renewables										
Pumped Storage										
Other										
2006 Generation in WA	**MWh**	**lbs of CO2**	**Tons of CO2**	**$5/ton**	**$/kWh increment ($5/ton)**	**$5/ton Price**	**$20/ton**	**$/kWh increment ($20/ton)**	**$60/ton**	**$/kWh increment ($60/ton)**
Coal	6,384,724	12,935,450,824	5,869,079	$29,345,396.61	$0.00	$0.01	$117,381,586.42	$0.02	$352,144,759.27	$0.0552
Petroleum	36,679	66,792,459	30,305	$151,525.54	$0.00	$0.14	$606,102.17	$0.02	$1,818,306.51	$0.0496
Natural Gas	7,499,318	8,346,740,934	3,787,088	$18,935,437.69	$0.00	$0.05	$75,741,750.76	$0.01	$227,225,252.29	$0.0303
Other Gases	334,734									
Nuclear	9,328,277									
Hydroelectric	82,007,629									
Other Renewables	2,502,510									
Pumped Storage	1,219,500									
Other	47,099									

Appendix E: Washington State Spreadsheets

Appendix E-Table II: Full Cost Pass through Calculations										
	Gen Mix	**No Carbon**	**Adjusted No Carbon**	**Adjusted $5/ton Incremental Increase**	**Adjusted $5/ton Carbon**	**Adjusted $20/ton Incremental Increase**	**Adjusted $20/ton Carbon**	**$60/ton Carbon**	**Adjusted $60/ton Carbon**	**Adjusted $60/ton Carbon**
Coal	5.90%	$0.0089	$0.0005	$0.0003	$0.0008	$0.0011	$0.0016	$0.0033	$0.0002	$0.0091
Natural Gas	0.03%	$0.0496	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Petroleum	0.03%	$0.1392	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	$0.0001	$0.0000
Nuclear	8.62%	$0.0016	$0.0001	$0.0000	$0.0001	$0.0000	$0.0001	$0.0000	$0.0001	$0.0000
Hydro	75.79%	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Other	2.41%	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Average Total			**$0.0007**	**$0.0003**	**$0.0010**	**$0.0011**	**$0.0018**	**$0.0033**	**$0.0004**	**$0.0091**
	Incremental $/kWh Increase									
	No Carbon	**$5/ton**	**$20/ton**	**$60/ton**						
Coal		$0.0046	$0.0184	$0.0552						
Natural Gas		$0.0025	$0.0101	$0.0303						
Petroleum		$0.0041	$0.0165	$0.0496						

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