Does a Regional Greenhouse Gas Policy Make Sense?
A Case Study of Carbon Leakage and Emissions Spillover

Yihsu Chen

Sierra Nevada Research Institute
School of Social Sciences, Humanities and Arts
School of Engineering
University of California, Merced
5200 N. Lake Rd., Merced, CA 95343, USA.
Email: yihsu.chen@ucmerced.edu.
Tel.: 1-209-228-4102; Fax.: 1-209-228-4047

Please do not cite without permission.

Abstract

The Regional Greenhouse Gas Initiative (RGGI) is a state-level effort by ten northeast states in the U.S. to control CO_2 emissions from the electric sector. The approach adopted by RGGI is a regional cap-and-trade program, which sets a maximal annual amount of regional CO_2 emissions that can be emitted from the electric sector. However, incoherence of the geographic scope of the regional electricity market is expected to produce two undesirable consequences: CO_2

leakage and NO_x and SO_2 emissions spillover. This paper addresses these two issues using transmission-constrained electricity market models. The results show that if the program is implemented in 2006, the leakage might be as high as 80–90%. This is accompanied with 60-95% and 50-70% potential increases of NO_x and SO_2 emissions spillover from power sector in non-RGGI states. The leakage and emissions spillover are to some extent attenuated by the price-responsive demand and the high allowance prices. This highlights the difficulties of designing a regional or local climate policy.

Keywords: Emissions Trading, Electric Market, CO_2 Leakage

JEL. Classification: C81, L11, L94

1. Introduction

Due to lack of federal leadership, a number of states in the United States have taken collaborative actions to control for greenhouse gas (GHG) emissions from the state governmental level. The efforts by the western and eastern states are called the Western Regional Climate Action Initiative and Regional Greenhouse Gas Initiative (RGGI), respectively. RGGI is a joint effort by ten states in the northeast United States targeted at regional CO_2 emissions (RGGI, 2008). These states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont. At the time of this writing, Washington, DC, remains as an observer to the RGGI. The goal of the policy is to reduce CO_2 emissions ten percent below the current level by 2019.

The approach adopted by RGGI is a source-based cap-and-trade program. A fixed number of emissions allowances are distributed to emissions sources (e.g., power generators), and these facilities need to have sufficient allowances to cover their annual emissions by the end of the compliance cycle. The emissions allowances may be traded in secondary markets. The compliance schedule set forth is that the CO_2 emissions will be capped at the current level during 2009-2015, followed by a gradual decline to 10 percent below the current level by 2019. Fossil-fueled generating units (e.g., gas, oil and coal) with a name capacity greater than or equal to 25 MW fall under the cap.

In the short run, the cap-and-trade programs are expected to achieve the policy goal at the least aggregate costs due to their efficiency gains from the heterogeneity of pollution control costs and emissions trading (Tietenberg, 2007). In the long run, it would provide economic incentives to encourage long-term generating capacity toward a mixture with less CO_2-intensive technologies. However, the lack of coherence of the geographic coverage under the environmental regulation and polluting sectors (i.e., RGGI vs. non-RGGI states) could lead to some unanticipated consequences that undermine the efficiency of environmental policies. This paper focuses on examining two effects: CO_2 leakage and emissions spillover. Under the current context, the term "*CO_2 leakage*" is defined as the displacement of CO_2 emissions from the capped region to uncapped region due to emissions trading.[1] For example, while Pennsylvania, Maryland and New Jersey are under a synchronized regional electricity market (i.e., PJM Interconnection), the absence of the Pennsylvania government's participation in the RGGI program could lead to some adverse effects on the total emissions in this region and distort capacity additions in the adjacent sates toward more CO_2-intensive generation mix in the long-run. "E*missions spillover*" refers to the situation at which the changes of pollution emissions other than CO_2 (e.g., SO_2 and NO_x) are affected due to CO_2 policies. In a sense, the former is a direct effect, created by CO_2 policies; whereas the emissions spillover is a secondary effect induced by the alternation of production merit order in response to the CO_2 policies. CO_2 leakage is not a unique problem to RGGI, but is also faced by California. In California, more than 20% of electricity consumption relies on the generators located in New Mexico, Arizona and other neighboring states, which use mainly coal-fired plants. It is estimated that this imported electricity accounts for more than 40% of the CO_2 of California emissions (CEC, 2006). Thus, CO_2 leakage is expected to occur if emissions trading is only applied to the California facilities.[2]

---

[1] We refer to CO_2 leakage here as the short run CO_2 displacement from capped to uncapped regions assuming firms are unable to relocate their polluting facilities to the un-regulated regions. Its long run counterpart is called "*pollution haven hypothesis*," which states that firms migrate their polluting activities to regions where the environmental standards are less strict. Yet, the conclusions from empirical studies concerning pollution haven hypothesis have been ambiguous in part due to the difficulties in controlling for factors that determine firms' investment decisions (Eskeland and Harrison, 2003).

[2] A number of approaches have been proposed to prevent CO_2 leakage by California policymakers under the AB32 Global Warming Solutions Act. They are different in the point-of-

This paper first defines CO_2 leakage and NO_x and SO_2 emissions spillover, followed by the discussions of the factors that would affect the level of leakage and emissions spillover. These are related to the CO_2 emissions rate, changes in the merit order, demand elasticity, transmission availability between capped and non-capped regions, and the correlation of CO_2 with the NO_x and SO_2 emissions rate. In particular, when the transmission line is congested prior to the emissions trading in the direction of the uncapped to capped regions, there would be no pollution leakage effect since no surplus transmission capacity can support incremental exports. However, the real transmission network involves complicated loop flows. Therefore, we use a transmission-constrained simulation model to estimate the level of CO_2 leakage and emissions spillover of NO_x and SO_2 in the RGGI and PJM regional electric market, assuming the program is implemented in 2006.

The paper is organized as follows. First, we give a summary of the literature concerning CO_2 leakage and emissions spillover in Section 2. In Section 3, we give the definitions of CO_2 leakage and NO_x and SO_2 emissions spillover, and address the factors that would affect them. In Section 4, we use an

---

regulations (liability entities) and how they treat imported electricity that the associated CO_2 intensity cannot be accurately determined. These include the load-based approach, which imposes an emissions cap on load-serving entities (LSE), and the first-seller approaches. Bushnell et al. give a good summary of the pros and cons of the source-based, the load-based and the first-seller approaches from the perspective of legal challenges, ability of preventing leakage and whether it would intervene with electricity market operations (Bushnell, 2008; Bushnell et al., 2008). Chen et al. (2008) address the economic and emissions equivalence of three approaches. Finally, another approach is "*Tradable Emission Certificates*" that decouple the sales of electricity and the corresponding CO_2 emissions intensity by setting a default/penalty CO_2 rate that is sufficiently high to encourage the out-of-state generators to voluntarily participate in the emissions trading (Gillenwater and Breidenich, 2007).

economic model to demonstrate how transmission congestion interacts with emissions trading and creates leakage. We also explain how the model is calibrated and report the simulated results, including the estimated price-responsive import curves, equilibrium prices and the level of leakage and emissions spillover in Section 5. Section 6 contains the conclusion and discussion.

2. Relevant Literature

The permanent migration of energy-intensive industries under local strict environmental regulations (e.g., pollution haven hypothesis) has been an active research area for decades. For instance, using a panel data of industrial plant siting from 1977-1987 in the United States, Henderson showed that the exit of the polluting industry when a county's ozone status is changed from attainment to nonattainment under the Clean Air Act (CAA) is statistically significant (Henderson, 1996). Eskeland and Harrison examined the pollution haven hypothesis from a global perspective, showing that whether strict domestic environmental regulation would lead to an efflux of polluting activities depends on the possible complementarities between capital and pollution abatement (Eskeland and Harrison, 2003). If per unit abatement costs decline is commensurate with the scale of output, the polluting industry may expand its output when facing stringent environmental regulation. Overall, their empirical study found weak evidence that supports the pollution haven hypothesis.

Whereas these two studies examine firms' long run decisions, our focus is on the firms' short run operations, assuming firms do not relocate their facilities in response to stringent environmental standards. The research concerning the *short run* CO_2 leakage in the electricity industry is limited, partly because the programs are either national in their scope (e.g., the SO_2 Acid Rain Program) or the programs' coverage overlaps with the majority of the regional electricity markets (e.g., the NO_x State Implementation Plan Call).[3]

One exception is the research by Fowlie (Fowlie, 2007), who defines the leakage as the difference in the emissions under incomplete and complete regulation. Fowlie showed that when environmental regulation is incomplete, the existence of forward markets would amplify the emissions leakage. The simulation of the California market shows that CO_2 leakage amounts to 62% and 65% of emissions reduction from regulated facilities with and without forward markets, respectively. However, how the CO_2 leakage would interact with transmission congestion between capped and uncapped regions is not addressed. Another relevant study by Demailly and Quirion examined the effect of two allowance allocation approaches (i.e., grandfathering vs. output-based) under the EU ETS (European Union Emission Trading Scheme) on the competitiveness and CO_2 leakage of the cement industry in Europe (Demailly

---

[3] The emissions leakage associated with other emissions programs such as the USEPA NO_x SIP Call is less likely to be a problem. There are two reasons. First, NO_x emission rates for typical peaking marginal units (e.g., natural gas combustion turbines) are relatively low; hence, the impact of emissions costs on power prices would be relatively small, at least during high demand periods. Second, the NO_x SIP program covers all states in the PJM market. Hence, none of the PJM generators would possess an economic advantage as a result of NO_x emissions trading.

and Quirion, 2006). They showed that substantial carbon leakage could occur under the grandfathering approach.

Emissions spillover has been examined by a number of studies (Burtraw et al., 2003; Greenstone, 2003; Holland, 2007). Burtraw et al. used an integrated assessment model to examine the local health benefits when regulating global pollutants like CO_2 (Burtraw et al., 2003). They found substantial ancillary benefits associated with NO_x and SO_2 when climate policy targets CO_2. Therefore, the emissions spillover is beneficial since a federal emissions cap is assumed in their model. Greenstone refers to emissions spillover as the "regulation-induced-substitution" (Greenstone, 2003). In particular, the paper distinguished two effects associated with emissions spillover: output reductions and inputs substitutions.[4] He found little evidence that the CAA led to an increase of pollution emitted from the iron and steel industry to waterways and the ground in 1987-1997. Recently, Holland examined CO_2 spillover of power plants from regulating NO_x under the CAA. He found that the designation of nonattainment in CAA is associated with a 20% reduction in CO_2 emissions due to output reductions (Holland, 2007).

This paper contributes to the existing literature on CO_2 leakage and emissions spillover in at least two aspects. First, we examine the short run effect

---

[4] In the context of the power sector, inputs substitution in the short run is equivalent to "merit order" changes due to the inclusion of emissions costs. As for output effects, two counteracting forces could lead to output changes: while output can be increased when facing higher prices assuming firms are price-takers, inclusion of emissions costs could result in a decline in the output. When the second factor dominates, firms would reduce their output, and vice versa.

on a market that is expected to be vulnerable to CO_2 leakage and spillover. Second, our model incorporates the transmission network, which is crucial in examining the substitution of outputs and the emissions distribution among generators with heterogeneous fuel costs and emissions rates when they face environmental regulation.

3. CO_2 Leakage and Emissions Spillover

CO_2 leakage is defined as the displacement of CO_2 emissions from RGGI to non-RGGI generators due to CO_2 policy. It is expressed in Equation (1) as the absolute value of the difference of CO_2 emissions in non-RGGI states with and without emissions trading ($\Delta CO2_{NonRGGI}$), normalized by the CO_2 emissions reduction in RGGI ($\Delta CO2_{RGGI}$). This definition is consistent elsewhere (RGGI, 2007).

$$CO_2 \text{ Leakage} = \left| (\Delta CO2_{NonRGGI} / \Delta CO2_{RGGI}) \right| \times 100\%. \qquad (1)$$

For instance, if leakage amounts to 80%, it implies CO_2 emissions in non-RGGI states increase by 80% of the amount of CO_2 reduction in RGGI states. Thus, CO_2 policy is literally only 20% as effective as it is designed. When electricity demand is fixed, the change in output from the RGGI generators is equal to the negative of that from the non-RGGI states (i.e., $\Delta \text{output}_{RGGI}=-\Delta \text{output}_{NonRGGI}$). The $\Delta CO2_{RGGI}$ ($\Delta CO2_{NonRGGI}$) in Equation (1) equals the product of $\Delta \text{output}_{RGGI}$ ($\Delta \text{output}_{NonRGGI}$) and the average emissions rate of these units that increase (decrease) their output. Thus, as long as one of the non-RGGI units that increases output has a non-zero CO_2 emissions rate, CO_2 leakage based on Equation (1) will be positive. If $\Delta CO2_{RGGI} < \Delta CO2_{NonRGGI}$, leakage will be greater than 100%. However, whether $\Delta CO2_{RGGI} < \Delta CO2_{NonRGGI}$ or vice versa is an empirical question, depending on the load level, merit order, generation mixes, etc. For instance, even if the average CO_2 emissions rate in the capped region is lower than that of the non-capped region, it is possible that $\Delta CO2_{RGGI} > \Delta CO2_{NonRGGI}$ for a given load level because the set of RGGI generators that alter their output normally have a higher CO_2 emissions rate than the average.

On the other hand, emissions spillover is defined as the increases in NO_x and SO_2 emissions in the non-RGGI states due to CO_2 policy. It is represented by Equation (2) as the difference between NO_x (SO_2) emissions in the scenarios with a positive allowances price (subscript 1) and the reference case (i.e., $\Delta Pol_{NonRGGI,1}$, where Pol =$\{NO_x, SO_2\}$), normalized by the emissions levels of the reference case (i.e., $Pol_{NonRGGI,0}$, where subscript 0 indicates reference case with a 0 allowances price). For instance, if the reference case's NO_x emissions are 100 ktons in non-RGGI states, a NO_x emissions spillover of 70% indicates that NO_x emissions elevate by 70%, or to 170 ktons. Thus, emissions spillover will always be positive when at least one unit that increases its output has a positive emissions rate.

$$\text{Emissions Spillover} = (\Delta Pol_{NonRGGI,1} / Pol_{NonRGGI,0}) \times 100\% \qquad (2)$$

Other factors that might also affect CO_2 leakage and SO_2 and NO_x emissions spillover include demand elasticity, transmission availability and changes in merit order. When demand is elastic, increase in electrficity prices induced by emissions trading will suppress electricity demand and result in less CO_2 leakage. If there is no surplus transmission capacity available for a non-RGGI region to export power, the CO_2 leakage is expected to be zero. In this case, CO_2 emissions reduction relies on redispatching among RGGI units

4. Simulation of the PJM Electricity Market and RGGI: Assumptions

This paper uses two transmission-constrained simulation models to quantify the extent of CO_2 leakage and the NO_x and SO_2 emissions spillover. While these two models only differ by the levels of demand elasticity, the mathematical structure of the two models is distinct. Hence, the solutions approaches are different. However, the two models produce the same solutions in the reference case when there is no emissions trading. Because the two models cover only a subset of the RGGI region and the PJM market, allowances prices (i.e., CO_2, CAA Title IV SO_2 and NO_x SIP Call) are treated exogenously as an additional component to the marginal cost.[5] In this section, we first summarize the background of the electricity market in Section 4.1. Model scenarios and assumptions are given in

---

[5] Beginning in 2009, there will be a number of concurrent NOx and SO_2 emissions trading programs implemented in the northeast and mid-Atlantic states. These include NO_x SIP Call (ozone season), CAA Title IV SO_2 (annual), and CAIR (Clean Air Interstate Rule) SO_2 (annual) and NO_x (annual and ozone season). While facilities are allowed to trade their SO_2 allowances between CAA Title IV and CAIR programs, some restrictions are applied to the transactions associated with CAIR NO_x (annual, ozone season) and NO_x SIP Call. For instance, NO_x SIP Call allowances may be used for compliance in the CAIR ozone season NO_x program, but not in the annual program. For details, please refer to the EPA website (USPEA, 2008).

Sections 4.2 and 4.3, respectively. The way we model price-responsive import is presented in Section 4.4.

4.1 The PJM Electricity Market

Figure 1 displays the geographic coverage and network of the electricity market simulated in the model. It covers six states, including Maryland, New Jersey, Pennsylvania, West Virginia, Delaware and Virginia and Washington, DC.[6] The market is represented by seventeen power control areas and twenty-four transmission lines. Each power control area is a load center at which load serving entities procure electricity on behalf of their customers. The network represents the transmission system above 500kV lines. The peak demand in 2006 in the model was approximately 102.6 GW, representing approximately 65% of the load in the PJM Regional Transmission Organization. The darker region in Figure 1 corresponds to the states that are not in the RGGI. These states account for roughly 40% generating capacity in the study region, but only demanded less than 28% of the electricity in 2006. Thus, substantial electricity is imported from non-RGGI to RGGI states.

---

[6] The PJM Interconnection market was first established in 1999, providing electricity to consumers residing in Maryland, New Jersey, Pennsylvania, Delaware and the District of Columbia. Since then, its footprint has evolved considerably. In particular, Rockland and Allegheny Energy joined in 2002, and three utilities, including Commonwealth Edison, American Electric Power and Dayton Power & Light, joined the PJM in 2004. The latest additions are Duquesne Light and Dominion Virginia, which became part of the PJM in 2005. Today, the PJM RTO (regional transmission organization) covers 13 states and DC, serving 51 million customers with the peak load equal to 156 GW.

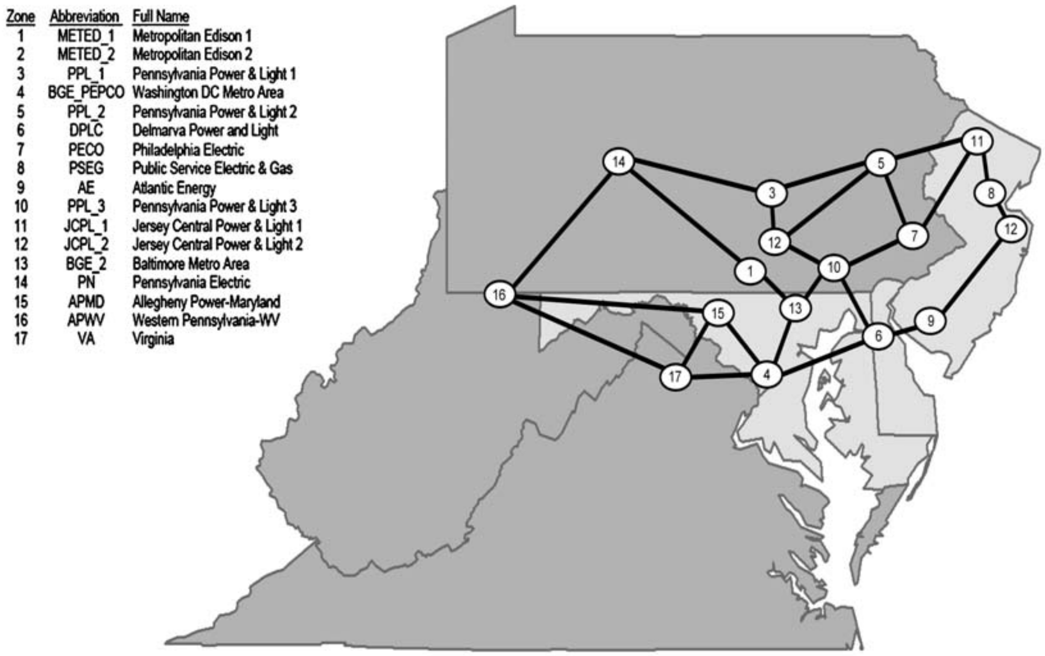

Figure 1: Transmission network in the model (source: www.pjm.com)

The states' capacity mix varies considerably. Table 1 summarizes the states' generating capacity by fuel types and capacity-weighted CO_2 emissions rates. The total installed capacity is 98.7GW in our model. Four states - Pennsylvania, Virginia, New Jersey and West Virginia - account for more than 85% of the total installed capacity for the market simulated in the study. West Virginia has more than 90% of coal capacity due to its abundant coal; in contrast, coal accounts for less than 15% for New Jersey. For Maryland, Pennsylvania and Delaware, roughly 45% of the capacity is coal, followed by natural gas plants.

Table 1: State Capacity[1] by fuel [MW] and capacity-weighted CO_2 emissions Rates [kg/MWh]

Type\States	MD	NJ	PA	DE	VA	WV	DC
Coal	4,331	1,819		971	5,361		-

			16,928			12,327	
Natural Gas	2,445	6,624	9,365	853	6,417	1,232	-
Oil	1,341	1,518	2	370	2,574	-	761
Nuclear	1,297	3,452	7,674	-	3,010	-	-
Others	527	537	2,416	-	3,281	204	-
Total	9,941	13,950	36,385	2,194	20,643	13,763	761
CO_2 [kg/MWh][2]	748	566	617	860	603	973	1,076

[1] Capacity is derated with forced and scheduled outage rates

[2] Capacity-weighted CO_2 emissions rate

The extent of CO_2 leakage and emissions spillovers depends on levels of the power prices, emissions rates of the generators that change their output levels and the correlation of emissions rates among different pollutants. Figures 2 and 3 show the cumulative generating capacity in an ascending order of the marginal costs (including fuel and variable O&M costs) along with the corresponding SO_2, NO_x and CO_2 emissions rates for RGGI and non-RGGI generators. In the RGGI states, coal, natural gas and oil plants represent 23.7%, 40.1% and 13.7%, respectively, of the installed capacity. In contrast, more than 45% of capacity in the non-RGGI states is coal, with a CO_2 emissions rate greater than 1000 kg/MWh. Thus, capacity in non-RGGI states is considerably dirtier than that in the RGGI. Moreover, these units generally have a marginal cost below $30/MWh, which is relatively cheaper than the most units in the RGGI states. Finally, the correlation of CO_2 emissions rates with NO_x and SO_2 is 0.53 and 0.44, respectively. Thus, if power plants in the non-RGGI states expand output when facing a CO_2 policy, it would likely simultaneously lead to increased emissions of SO_2 and NO_x.

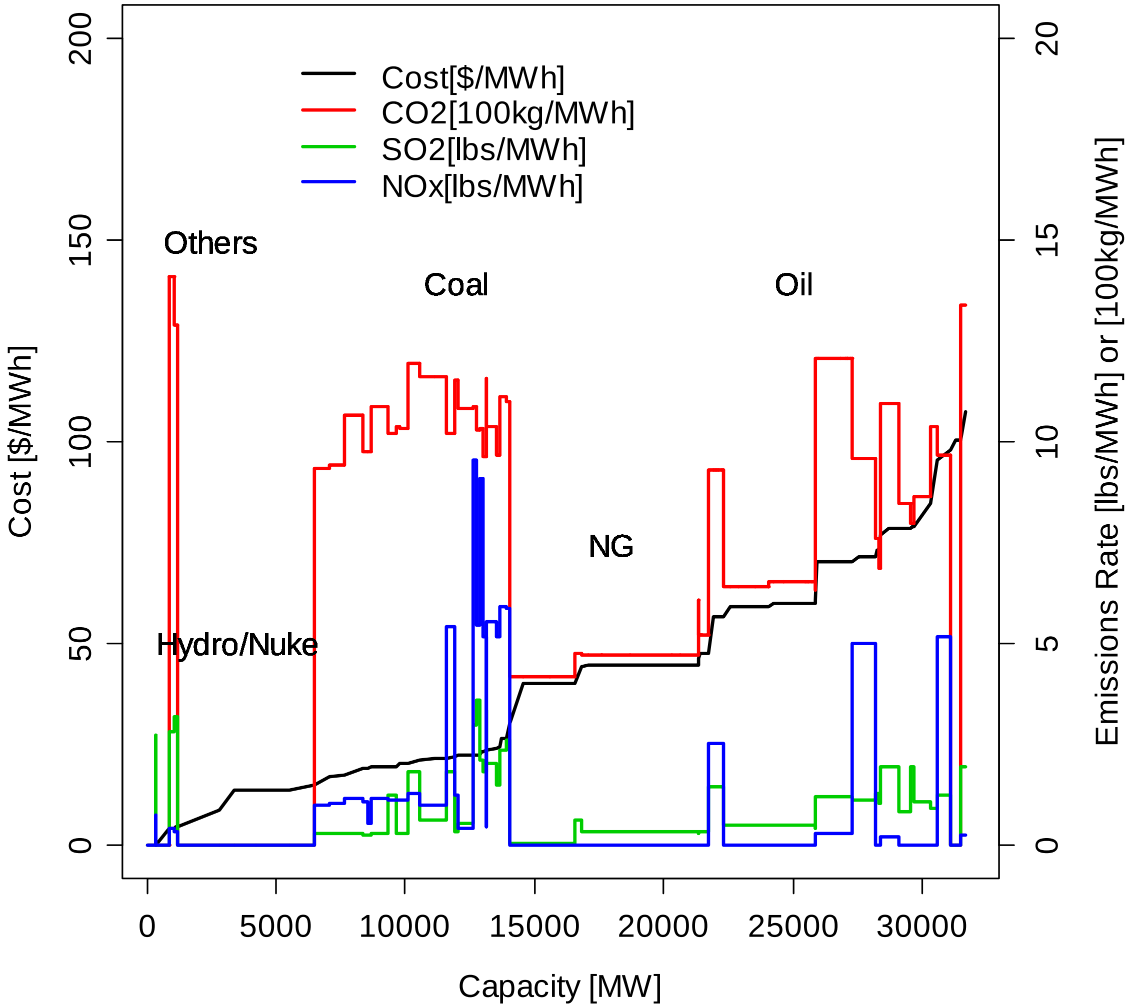

Figure 2: Cumulative capacity, NO_x, SO_2 and CO_2 emissions rates of RGGI states

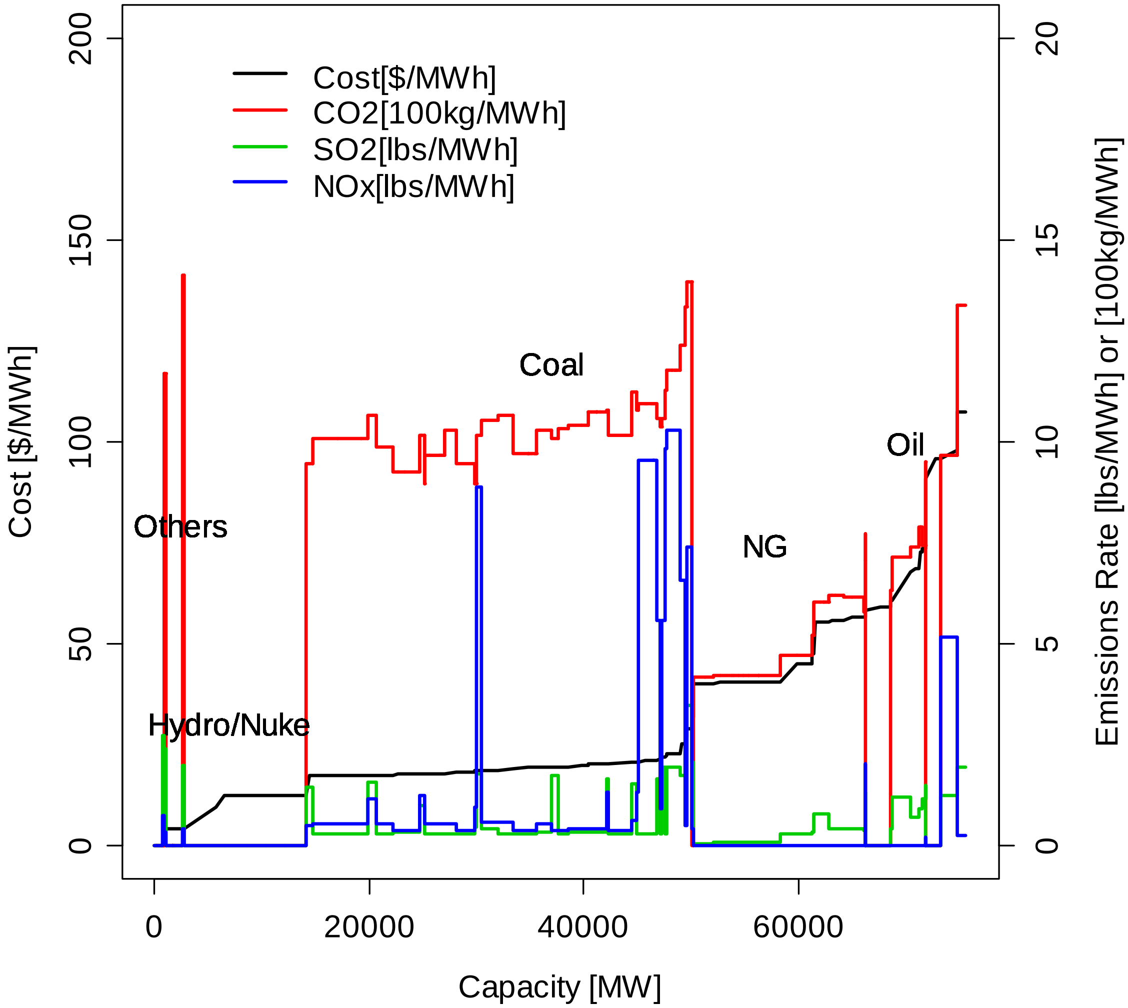

Figure 3: Cumulative capacity, NO_x, SO_2 and CO_2 emissions rates of non-RGGI states

4.2 Model Assumptions

Two models are used in this paper to analyze the impact of emissions trading on carbon leakage and emissions spillover. Both models treat allowances prices exogenously by incorporating CO_2 costs in the production costs based on emissions rates (i.e., CO_2 cost = CO_2 emissions rate×allowance price). While demand is fixed in the first model, the second model allows demand to be price-responsive and is a competitive version of what was used to analyze market power in the PJM and NO_x allowances markets (Chen and Hobbs, 2005). It was also used to examine the impact of Maryland's potential participation in RGGI (Ruth et al., 2008). Both models are calibrated using 2006 data, including fuel costs, loads, and allowances prices of pollutants other than CO_2. The imports of electricity from outside of the study domain are modeled by the price-responsive import supply curves derived from empirical data, as opposed to being fixed (Chen and Hobbs, 2005). As a result, the first model is not a conventional linear program since the primal problem involves dual variables (i.e., the electricity price). We overcome this by solving the model using an algorithm that iterates on the exported quantity. The second model is classified as a linear complementarity problem and can be readily solved using PATH (Ferris and Munson, 2000).

The simulation period is year 2006, comprising 8,760 hours. Yearly load is represented by nine periods: permutation of three seasons (i.e., summer, winter and spring/fall) and three periods (e.g., mid daytime, morning/evening and night). Unlike NEMS (National Energy Modeling System) which defines summer as from June to September, we include May in the summertime in order to model ozone season (see Table 2). The size of the blocks varies from 450 to 1,683 hours.

The allowances prices of the CAA Title V SO_2 and NO_x SIP programs are assumed to be 769 and 1,840 $/ton, respectively. These values are based on 2006 data reported by Platts (Platts, 2007).

4.3 Scenario Definitions

To examine the effect of CO_2 costs on leakage and emissions spillover, we perform 15 runs of simulation, varying allowances prices by an increment of $1/ton for 0-7 $/ton and 10–40 $/ton with a $5/ton increment (see Table 2). Although an allowances price of $7/ton is determined by the RGGI as the safety valve[7], we model a broader range of allowances prices for two reasons. First, it allows us to study CO_2 leakage and emissions spillover under the extreme conditions. Second, a price of $40 /ton is compatible with the experience of the EU ETS In the first phase of implementation (Chen et al., 2008). The finer increment at the lower allowance prices is modeled since it corresponds to the likely possible range of RGGI allowances prices.

Additionally, we study the implications of demand elasticity on carbon leakage and emissions spillover by modeling two levels of elasticity: zero and 0.2. As short run demand elasticity for electricity is nearly zero, an elasticity of 0.2 is likely the upper bound of the actual market experienced (Espey and Espey,

---

[7] According to the RGGI MOU and the Model Rule (RGGI, 2008), there are two price triggers that provide more compliance flexibility and price damping mechanism. The first and second price triggers occur when the 12-month rolling average equals or exceeds $7/ton and $10/ton. If these two events happen, the amount of offset allowances that can be used for compliance increases from 3.3% to 5% and to 10%, respectively.

2004). Again, this wide range of assumption concerning elasticity enables us to examine its impact on emissions spillover and leakage. In summary, a total of 30 runs are simulated, 15 apiece for fixed and price-responsive demand, with allowance prices varying from 0 to $40/ton.

Table 2: Scenarios and model assumptions

	Model I		Model II	
Formulation	LP (fixed demand)		LCP (price-responsive demand)	
Elasticity	0		-0.2	
Allowances Prices	$0/ton to $40/ton (15 scenarios)			
Periods	3 Seasons		3 Blocks	
	Summer:	May -- Sept	Mid Day:	09-16
	Winter:	Dec -- Feb	Morning /Evening:	06-08 and 17-24
	Fall/Spring:	Mar, Apr, Oct, Nov	Night time:	01-05
Network	17 nodes and 24 transmission lines			

4.4 Imported Electricity

The import or export of power to the adjacent market, i.e., the New York Independent System Operator (NYISO), is assumed via the Jersey Central Power and Light (JCPL1). The average hourly export from PJM to NYISO in 2006 was 500MW, varying from 2,580 (import) to -2,474MW (export). The variation in the magnitude of export and import is a function of many factors, such as system conditions (e.g., unexpected and scheduled outage of transmission lines and power plants), load levels and price differentials between two systems. However, we only consider economic drivers by modeling the relationship between price and demand, and we ignore other external uncertain events (e.g., transmission failures). If external factors are the underlying events that determine the quantity of export (or import), we believe they are rare compared to the overall sample size.

To simulate the imported electricity properly, the analysis constructs price-responsive import supply curves for the flows between NYISO and JCPL1. We assume the importers are price-takers who determine the amount of electricity to deliver to the PJM according to the interface's electricity prices (e.g., JCPL1). However, the relationship between prices ($p_{JCPL1,t}$) and imported quantity ($z_{JCPL1,t}$) are likely be endogenous. Thus, this violates the general Ordinary Least Square (OLS) assumptions, and leads to biased estimators if used. We solve this problem by using hourly nodal loads in JCPL1 ($Load_{JCPL1,t}$) as the instrument variables (IV) for the electricity prices ($p_{JCPL1,t}$) and apply two-stage least square regressions (2SLS). In the first stage, we regress $p_{JCPL1,t}$ on $Load_{JCPL1,t}$ in Equation (3). In the second stage, we regress the import $z_{JCPL1,t}$ on variables $p_{JCPL1,t}{}^*$, which are predicted prices from the first stage (Equation (4)).

We argue that nodal loads in JCPL1 are valid IV because the loads are likely to be known based on the utilities' load forecast models, which are associated with prices but exogenous to the importers' decision. The same approach is also applied elsewhere (Mansur, 2007).

$$p_{JCPL1,t} = f(Load_{JCPL1,t}) + \varepsilon_t \qquad (3)$$

$$z_{JCPL1,t} = g(p_{JCPL1,t}{}^{*}) + \varepsilon'_t \quad (4)$$

We use 2SLS to estimate import curves for each period considered in the model. In both stages, linear functions are assumed by examining the scatter plots of functions *f* and *g*. Nonlinear functions can be used, but it would increase the computational complexities and will not change our conclusion.

5. Simulation Results

This section presents the results of our modeling analysis. First, we introduce how we calibrate the models in Section 5.1. Then, we summarize the results of estimating price-responsive import curves in Section 5.2. The equilibrium prices are presented in Section 5.3. We summarize the results concerning CO_2 leakage and emissions spillover in Section 5.4.

5.1 Model Calibration

The model under the reference case was first compared with 2006 PJM locational marginal prices (LMPs) and emissions data reported by PJM and the U.S. Environmental Protection Agency (USEPA) Continuous Emission Monitoring System (CEMS) (USEPA, 2007), respectively.

PJM reported hourly LMPs at buses, control areas and the entire PJM market (PJM, 2007). Our comparison is based on the data associated with control areas. We ignore the upper and lower 5% in the PJM LMPs dataset to avoid the biases introduced by the outliers. Figure 4 shows the results. Each point in the plot represents a pair of the simulated price by model (y-axis) and the reported LMP prices by PJM (x-axis) of a control area in a given period. If the simulated prices perfectly predict LMPs, the plot will land on the 45-degree line. On the other hand, if points fall below (above) the 45-degree line, it indicates under (over) predictions. Overall, the model performs well in the low-demand periods, overestimates the LMPs in the high-demand periods and underestimates in the moderate-demand and the high periods. The correlation of the two series is roughly 0.73.

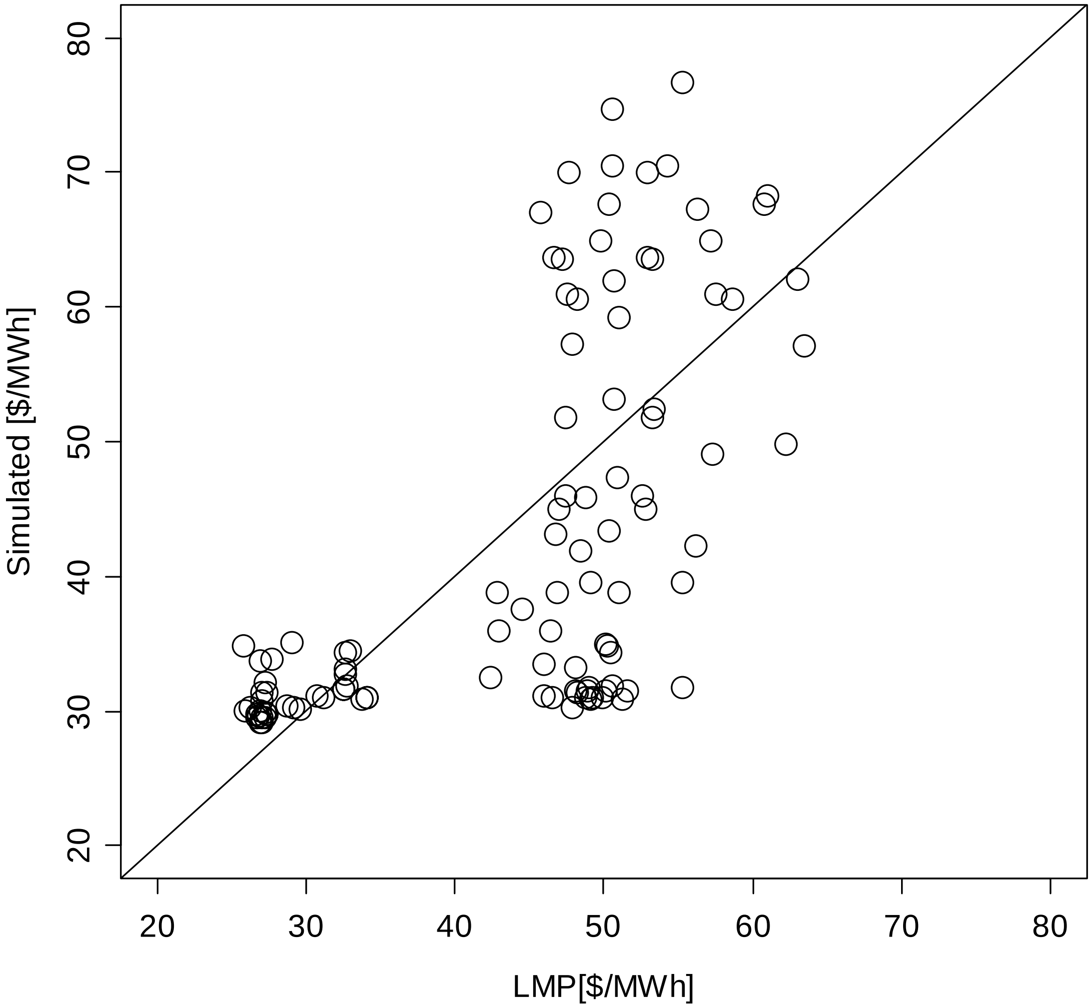

Figure 4: Plot of simulated prices of reference case (CO_2 allowances price=0 $/ton) against PJM reported locational marginal prices

For regulatory purposes, the USEPA maintains the CEMS dataset and reports hourly emissions of various pollutants emitted from most fossil-fueled power plants. To compare the model predictions with CEMS data, we aggregate CEMS hourly emissions of each pollutant to the state level for the year 2006. The same plot that compares CEMS and the model's predicted emissions of CO_2, NO_x

and SO_2 is represented in Figure 5. Each point is a pair of the simulated (y-axis) and the reported annual emissions of a pollutant for a given state by CEMS (x-axis). The plot suggests that the model performs well in predicting pollution emissions with high correlation coefficients between two datasets. Most points lie not too far off the 45-degree line.

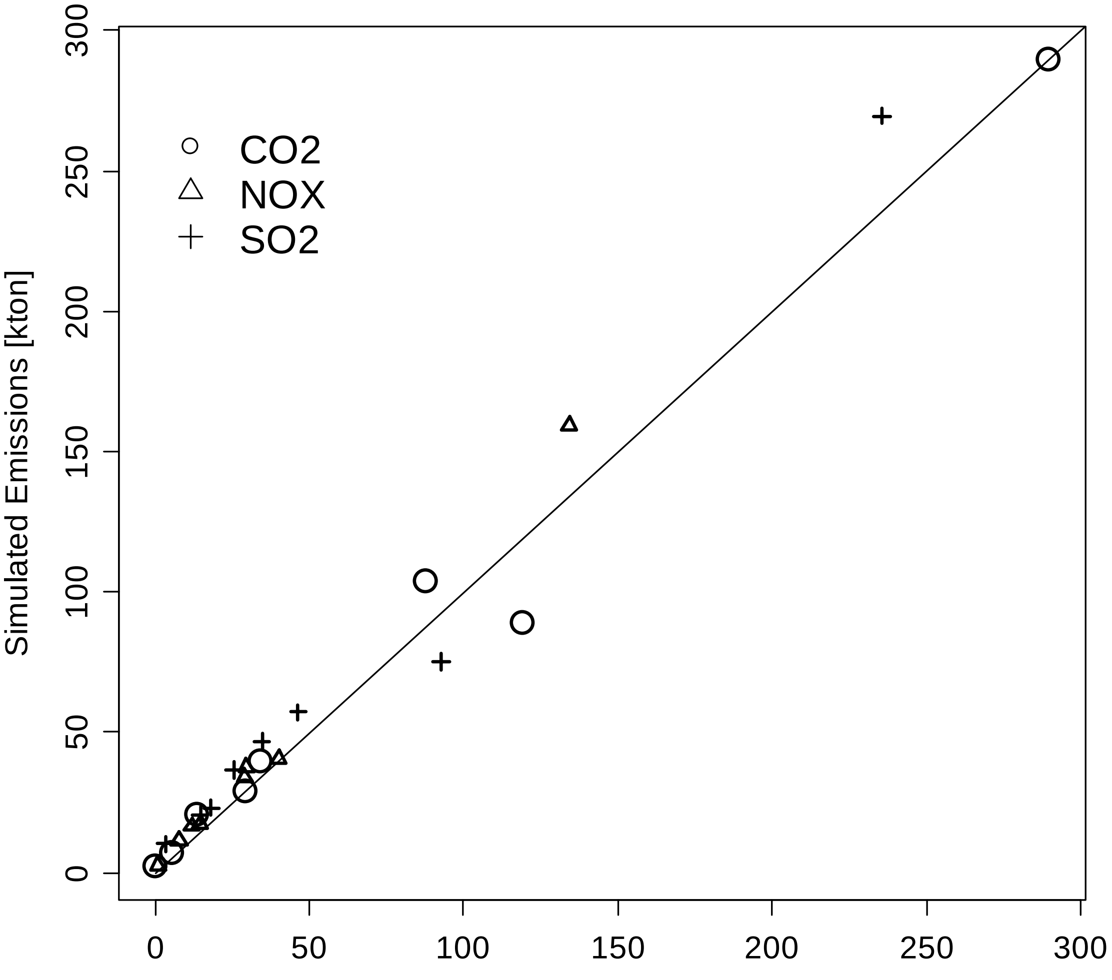

Figure 5: Plot of simulated emissions of reference Case (CO_2 allowance price=0) against CEMS reported emissions in 2006

5.2 Price-responsive Import Curves

Table 3 summarizes our estimates of price-responsive import curves by periods for the interface between JCPL1 and NYISO. Except for period 4, the values of R^2 in the first stage are above 0.5. This suggests that the nodal load in JCPL1 is a valid IV for electricity prices. The results from second stage show that except the periods 6 and 9 having a low R^2, other periods are at least 0.2. The positive slope indicates that more export to the NYISO would occur when JCPL1 experiences a higher price. On average, for $1/MWh increase in JCPL1's electricity price, the export to NYISO will increase by 20-40 MW, depending on the periods.[8]

Table 3: Results of price-responsive import curves using 2SLS

	First Stage		Second Stage		
Period	N	R^2	β_0	β_1	R^2
1	1224	0.66	-1524.7**	27.8**	0.63
2	1683	0.72	-1836.5**	27.2**	0.62
3	765	0.64	-2536.3**	37.5**	0.31
4	976	0.26	-2532.2**	40.9**	0.20
5	1342	0.56	-1798.7**	24.7**	0.22
6	608	0.51	-2268.8**	32.7**	0.11
7	720	0.44	-1739.8**	25.8**	0.21
8	990	0.50	-1752.2**	22.4**	0.35
9	450	0.53	-1806.2**	18.8**	0.05

** indicates statistically significant at 1% level

5.3 Equilibrium Electricity Prices

---

[8] We also performed 2SLS analysis for the LSEs in mid-west states (e.g, Ohio) but the results are less conclusive. The R^2 (not reported here) in the first stage is generally low, indicating that nodal load in PN is not a valid instrument variable. The R^2 in the second stage is also very small. As a result, we use the average import/export in each period as our boundary condition.

Figure 6 plots the equilibrium electricity prices (sales-weighted yearly average) of RGGI and non-RGGI states (indicated by NRGGI) under the fixed (indicated by 0) and the price-responsive (indicated by 0.2) demand assumptions against CO_2 allowance prices. Higher electricity prices are observed in RGGI states than in non-RGGI states by 3-8 $/MWh, since RGGI states are a net importer of electricity in most periods. As a result of emissions trading, not only electricity prices in the RGGI states increase but also the power prices in the non-RGGI states, due to different reasons. In RGGI states, increases in the electricity prices are a direct outcome of incorporating CO_2 costs in the supply curves. In contrast, increases in electricity prices in the non-RGGI states are because of the expansion of power sales from the generators located in the non-RGGI to RGGI states in response to higher prices experienced in the RGGI states. A comparison of equilibrium prices under fixed and price-responsive demand shows that demand elasticity suppresses electricity consumption and attenuates prices impacts induced by CO_2 trading by 0–4 $/MWh on average. The difference is amplified when supply intersects demand in the more elastic segments in scenarios with higher allowances prices.

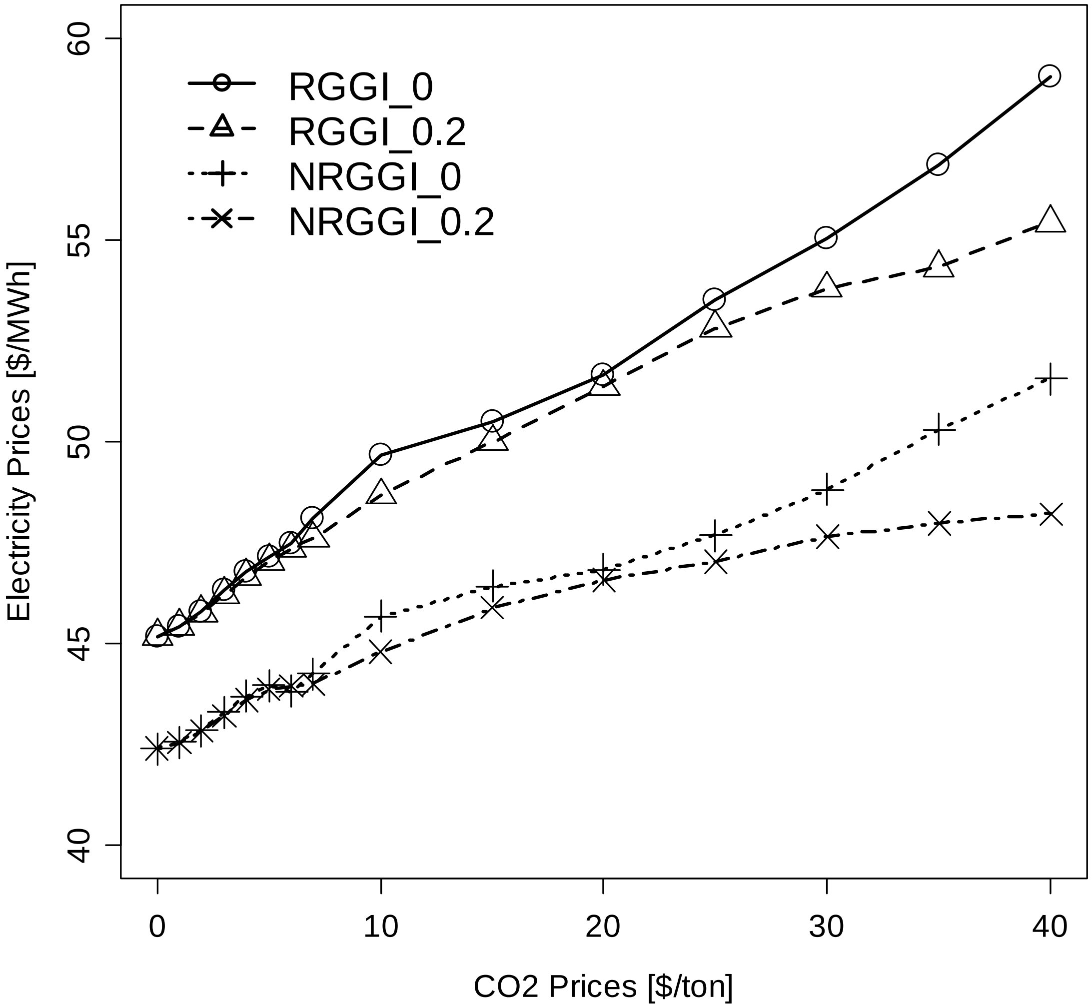

Figure 6: Sales-weighted annual electricity prices of RGGI and non-RGGI States under different levels of CO_2 allowances prices

5.4 CO_2 Leakage and Emissions Spillover

Simulated results of pollution emissions are presented in Figure 7, consisting of six plots: the upper and the lower plots correspond to the scenarios with fixed and price-responsive demand (elasticity=0.2), respectively. Emissions of three pollutants, i.e., CO_2, NO_x and SO_2, against CO_2 allowances prices are presented in the plots from left to right columns. Each curve is explained as follows. "Reference" represents the sum of emissions from RGGI and non-RGGI states in the absence of CO_2 emissions trading. The next three curves (i.e., Total, NRGGI and RGGI), respectively, represent the sum of emissions from RGGI and non-RGGI, and from non- RGGI and from RGGI states when emissions trading program is implemented. The next curve represents CO_2 leakage or emissions spillover of NO_x and SO_2, displaying as a percentage.

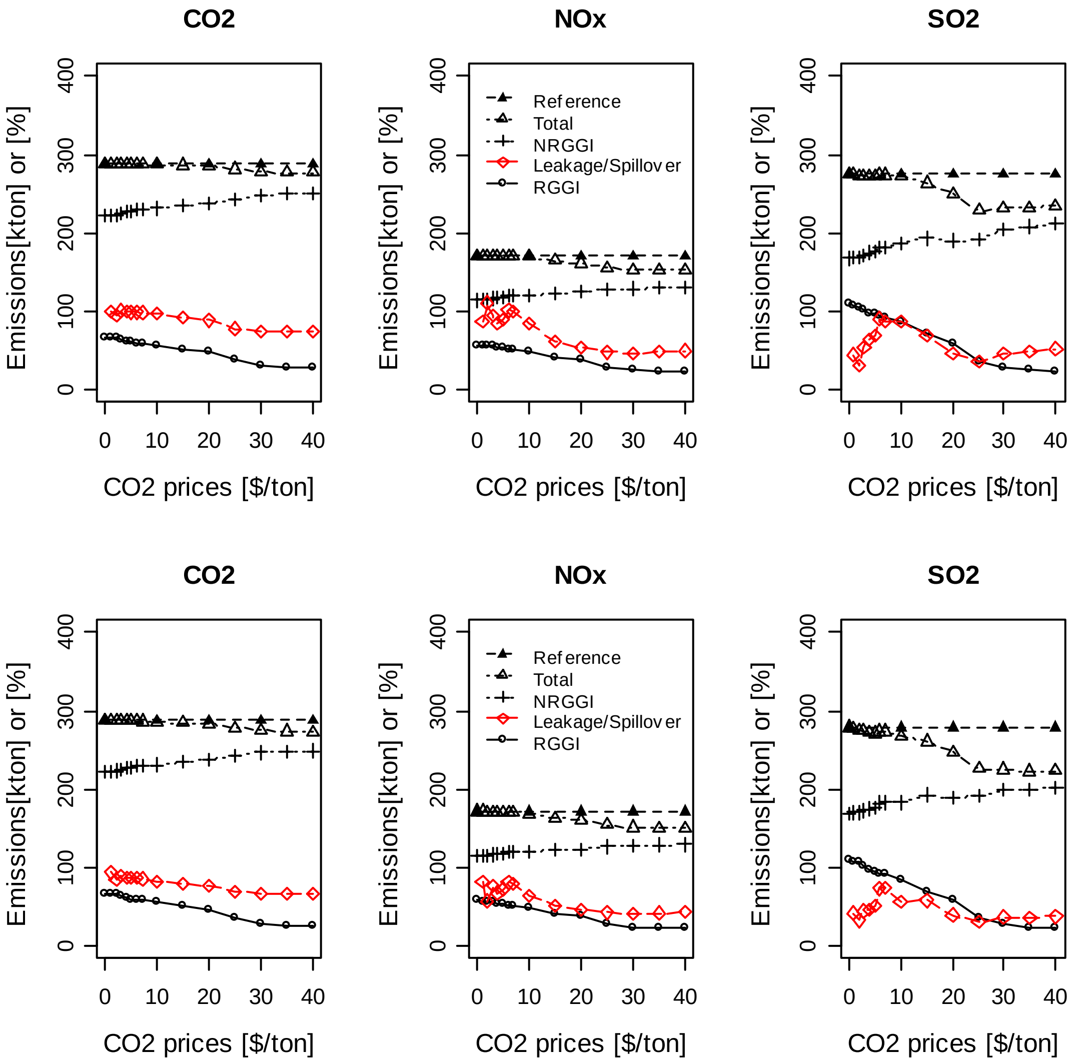

Figure 7: Plots of RGGI and non-RGGI, total and reference CO_2, NO_x and SO_2 emissions at different levels of CO_2 allowances prices under fixed (upper plots) and price-responsive demand (lower plots)

We first discuss the changes in the CO_2 emissions from the RGGI and non RGGI states. Introduction of CO_2 emissions trading puts a downward pressure on the CO_2 emissions from power plants located in the RGGI states since it becomes economically less desirable to operate units with higher emissions rates even if their fuel costs are lower. The amount of CO_2 reduction from RGGI states is positively associated with the levels of CO_2 allowances prices. When demand is fixed, these reductions represent roughly 2.8% of the emissions in reference case for per $/ton CO_2 costs (i.e., the slope of RGGI curve). In contrast, CO_2 emissions in non-RGGI states are elevated as a result of the increased export to RGGI states. The emissions increase on average by 0.47% per $1 /ton of CO_2 costs (i.e., the slope of NRGGI curve). Since both curves are nearly linear, it implies that the effect is consistent over the different levels of allowances prices.

If demand is price-responsive, the CO_2 emissions reduction effect increases slightly to 3.1% per $/ton of CO_2 costs. Thus, approximately 0.3% is attributed to the 0.2 of demand elasticity. CO_2 emissions from non-RGGI states increase by the same amount in the price-responsive and fixed demand scenarios for $1/ton increase in allowances costs.

As for the changes in NO_x and SO_2 emissions, the simulation results suggest two pollutants are projected to increase by 0.47% (0.43%) and 0.70% (0.58%) for per $/ton increase in the CO_2 allowances costs under fixed (price-responsive) demand scenarios for non-RGGI states, respectively.

In terms of CO_2 leakage based on Equation (1), when demand is fixed, our simulation suggests that CO_2 leakage could amount to more than 90% when the allowances price is less than $7/ton. That is, RGGI states' CO_2 emissions reduction is nearly completely void because of the increased emissions from non-RGGI states, and the CO_2 policy could only be less than 10% effective. The leakage varies from 80% to 90% when allowances prices change from $10/ton to $40/ton. Therefore, the effect, to some extent, is attenuated by high allowances prices. This is partially because in general there is a negative correlation between the cost and the CO_2 emissions rate among generators. Hence, the non-RGGI generators that would increase their output at a lower allowances price are normally less expensive but more polluting than the set of generators that increase their output when allowances prices are higher (Figure 3). To see this, Figure 8 plots the output-weighted CO_2, NO_x and SO_2 emissions rates of the sets of RGGI (non-RGGI) units that decrease (increase) their output related to the reference case against the levels of CO_2 costs under the fixed demand cases. Since the demand is fixed, the magnitude of leakage depends on the relative CO_2 emissions rates of those units that change outputs in each run related to the reference case (see Section 3). If we assume that the CO_2 emissions rates of each generator in the RGGI states are equal (i.e., the $\Delta CO2_{RGGI}$ in equation (1) is unchanged in each run), the magnitude of the CO_2 leakage would then depend on the emissions rates of the non RGGI units that increase their output. As shown in Figure 8, since the output-weighted CO_2 emissions rate continues to decline as the allowances prices increase (the left most graph), this implies that CO_2 leakage is smaller when allowances costs are high. Finally, the leakage impact is somehow neutralized by 10% when demand is price-responsive: 80-90% for allowances prices below $7/ton and 70-80% at higher allowances prices. Thus, given the current RGGI rules, it might be reasonable to conjecture that the CO_2 leakage might be around 80-90% under 2006 load conditions.

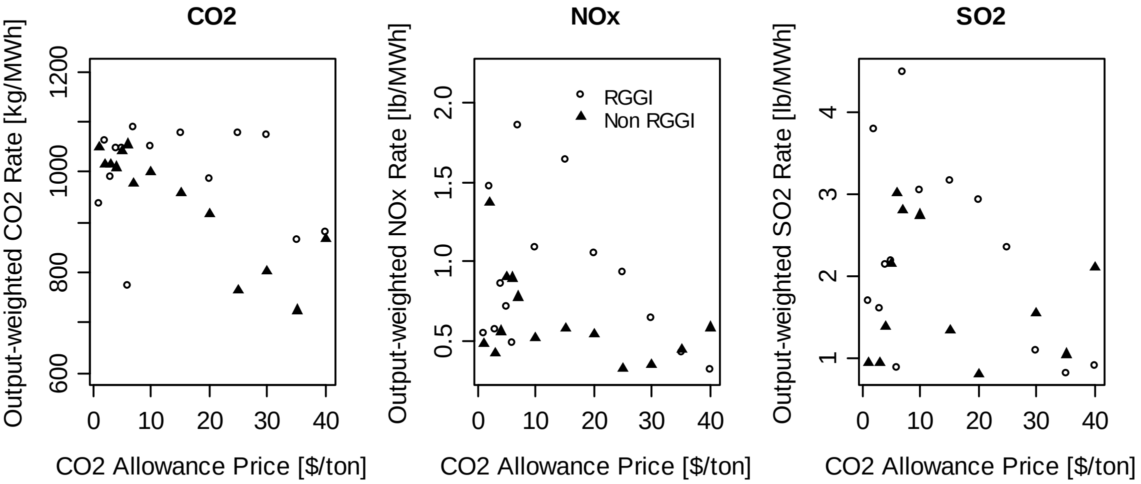

Figure 8: Plots of output-weighted emissions rates of the RGGI (non RGGI) units that increase (decrease) their output relative to the reference case against CO_2 allowances price under the fixed demand cases.

In terms of NO_x and SO_2 emissions spillover, it amounts to 60-95% and 50-70% among the range of the allowances prices simulated in this study for two pollutants, respectively. However, the trend is not monotonically decreasing, but sharply declines first, reaches its peak at around $7/ton and gradually tapers off. This is because the set of non-RGGI generators that alter their output is different when allowances prices change. As the allowances price approaches 7 $/ton, the set of generators that expand their output is more NO_x- and SO_2-intensive while their emissions rates are relatively low when allowance prices become higher (Figure 8).

Finally, in the range of allowances prices we consider, the “Total” series never exceeds “Reference” in Figure 7 for all three pollutants. This suggests when emissions trading is implemented, the region as a whole is better off with less pollution emitted into the air from power plants. However, when allowances prices exceed $25/ton, the results suggest that Total curves associated with SO_2 emissions begin to ramp up under the fixed demand scenarios. This does not occur to NO_x and CO_2, which continue to decline even at high allowance prices. Thus, only if allowances prices become extremely high, the undesirable outcomes that SO_2 emissions become worse than that prior to the emissions trading would possibly occur.

6. Conclusion and Discussion

The Regional Greenhouse Gas Initiative (RGGI) is a state-level effort by ten northeast states in the U.S. to control CO_2 emissions from the electric sector. However, incoherence of the geographic scope of the Pennsylvania-Maryland-New Jersey Interconnection (PJM) regional electricity market and the RGGI is expected to produce economic incentives for generators in PJM that are not subject to RGGI to expand their output. This paper addresses two distinct but related issues: CO_2 leakage and NO_x and SO_2 emissions spillovers. Since the market analyzed in this paper is a subregion of RGGI, we treat CO_2 costs exogenously by imposing CO_2 costs in the supply curves based on emissions rates (CO_2 cost=CO_2 allowances price×CO_2 emissions rates). We perform two sets of simulation: fixed demand and price-responsive demand with 0.2 elasticity. The modeling results suggest that demand elasticity to some extent attenuates CO_2 leakage and emissions spillover by negating increased electricity prices induced by emissions trading. In particular, this paper shows CO_2 leakage offsets more than 80-90% or 70-80% of emissions reduction under the fixed and price-responsive demand cases. As for emissions spillover, it is estimated to be 60-95% and 50-70% for NO_x and SO_2, respectively. Finally, given that the RGGI CO_2 allowances price is effectively capped at $7/ton, this suggests that first, CO_2 leakage is likely to offset 80-90% of emissions reduction induced by RGGI, and second, the undesirable consequence that regional CO_2 emissions would exceed the level prior to emissions is unlikely to occur.

Compared to other studies examining the leakage of RGGI, our results predict a significantly higher level of CO_2 leakage. One study examining the CO_2 leakage in RGGI concludes that in a "middle-of-the-road" scenario, the cumulative leakage is in the magnitude of 30% through 2015 (RGGI, 2007, p. 9). We discuss the possible reasons of the difference as follows. First, our study is a short run analysis with a fixed generation asset, and does not model long run investment decisions. For instance, RGGI (2007) concludes that much of the CO_2 leakage occurs because of the increases in output from the newly built, gas-fired plants in non-RGGI states (Figure 1, p. 10). Given that per MWh displacement of output from gas-fired units is roughly half of the coal-fired generators, the leakage is expected to be higher in our analysis. In contrast, if coal-fired plants are the dominant technology for the new investment, the leakage is expected to be larger in the long run. Second, our model covers only a subset of the region modeled by RGGI (2007), and it is possible that our estimated leakage is biased upward if the construction of our model ignores some less CO_2-intensive units that could expand their output under emissions trading.

Although the large magnitude of CO_2 leakage estimated by our models seemingly suggests that the effectiveness of RGGI could be greatly compromised, the quantitative outcomes concluded in our analysis should be taken cautiously. The analysis in this paper is subject to a number of limitations. We offer the following two reasons that might lead to an underestimate of CO_2 leakage. First, while the import from Ohio is treated exogenously, the CO_2 emissions associated with this imported electricity are not accounted for. Since generators in the Midwest region rely mainly on coal as the main fuel sources, significant CO_2 emissions would expect to increase. Thus, our calculation might underestimate CO_2 leakage. Second, as the short run elasticity demand is nearly inelastic, our assumption of 0.2 is around the upper bound of values in the literature. Thus, our results of CO_2 and emissions spillover based on the fixed demand assumption might be more reasonable.

Regardless its limitations, our analysis does shed some light on the fact that leakage and spillover could be a serious problem given the set of parameters (e.g., 2006 load conditions) and the assumptions in the model. This again highlights the difficulties of designing a regional solution for a problem with a larger geographic scope. As the proceedings from the allowances auctions in RGGI are expected to be recycled to various energy efficiency programs, it has been shown that it might somehow mitigate CO_2 leakage through the reduction of electricity demand and thus electricity prices in the long run (Ruth et al., 2008). Other issues that need to be carefully examined include the redistribution of economic rents from consumers in the RGGI states to the producers from other states due to higher electricity prices.

Acknowledge

This research is partially supported by the research funding from University of California, Merced the Graduate Research Council. The author would like to thank Pedro Linares, Karen Palmer, Enzo E. Sauma, Jos Sijm and Lizhi Wang for their helpful comments for the early version of the paper.

References

Burtraw, D., Krupnick, A., Paul, A., Palmer, K., Toman, M. and Bloyd, C., 2003. Ancillary Benefits of Reduced Air Pollution in the US from Moderate Greenhouse Gas Mitigation Policies in the Electricity Sector. Journal of Environmental Economics and Management **45**: 650-673.

Bushnell, J., 2007. The Design of California's Cap-and-Trade Program and Its Impact on Electricity Markets. Climate Policy **8**: 277-292

Bushnell, J., Peterman, C. and Wolfram, C., 2008. Local Solutions to Global Problems: Climate Change Policies and Regulatory Jurisdiction, Review of Environmental Economics and Policy. **In press**

California Energy Commission, 2006. 2006 Net System Power Report, California Energy Commission CEC-300-2007-007

Chen, Y., Liu, A. and Hobbs, B.F., 2008. Economic and Emissions Implication of Load-based, Source-based and First-seller Emissions Trading Programs under California AB32. University of California Energy Institute, EPE-022.

Chen, Y. and Hobbs, B. F., 2005. An Oligopolistic Power Market Model with Tradable NOx Permit. IEEE Transactions on Power System **20**(1): 119-129.

Chen, Y., Sijm, J., Hobbs, B. F. and Lise, W., 2008. Implications of CO_2 Emissions Trading for Short-run Electricity Outcomes in Northwest Europe. Journal of Regulatory Economics **In press**.

Demailly, D. and Quirion, P., 2006. CO_2 Abatement, Competitiveness and Leakage in the European Cement Industry under the EU ETS: Grandfathering versus Output-based Allocation. Climate Policy **6**(1): 103-113.

Eskeland, G. S. and Harrison, A. E., 2003. Moving to Greener Pastures? Multinational and the Pollution Hypothesis. Journal of Development Economics **70**(1): 1-23.

Espey, J. A. and Espey, M., 2004. Turning on the Lights: A Meta-analysis of Residual Electricity Demand Elasticities. Journal of Agricultural and Applied Economics **36**(1): 65-81.

Ferris, M. C. and Munson, T.S., 2000. PATH User Guide: Version 4.3, GAMS Development, www.gams.com/docs/pdf/path.pdf.

Fowlie, M., 2007. Incomplete Environmental Regulation and Leakage in Electricity Markets. Berkeley, University of California Energy Institute CSEM-175, www.ucei.berkeley.edu/PDF/csemwp175.pdf.

Gillenwater, M. and Breidenich, C., 2007. Internalizing Carbon Costs in Electricity Markets: Using Certificates in a Load-based Emissions Trading Scheme. Princeton, NJ, Woodrow Wilson School of Public and International Affairs, Princeton University

Greenstone, M., 2003. The Effect of the Clean Air Act on Water and Ground Pollution. The American Economics Review Papers and Proceedings **93**(2): 442-448.

Henderson, J. V., 1996. Effects of Air Quality Regulation. The American Economics Review **86**(4): 789-831.

Holland, S. P., 2007. CO2 Spillover effects from the Environmental Regulation of Power Plants, University of North Carolina, Greensboro, www.ucei.berkeley.edu/PDF/HollandCO2.pdf.

Mansur, E., 2007. Upstream Competition and Vertical Integration in Electricity Markets. Journal of Law and Economics **50**(1): 125-156.

Platts, 2007, www.platts.com/

PJM, 2007, Market, www.pjm.com/markets/markets.html

RGGI, 2007. Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms, RGGI, www.rggi.org/docs/il_report_final_3_14_07.pdf.

RGGI, 2008. Regional Greenhouse Gas Initiative: An Initiative of the Northeastern & Mid-Atlantic States of the U.S., www.rggi.org/.

Ruth, M., Gabriel, S.A., Palmer, K., Burtraw, D., Paul, A. Chen, Y., Hobbs, B. F. , Irani, D., Michael, J., Ross, K. M. , Conklin, R. and Miller, J., 2008. Economic and Energy Impacts from Participation in the Regional Greenhouse Gas Initiative: A Case Study of the State of Maryland. Energy Policy 36: 2279-2289.

Tietenberg, T., 2007. Environmental and Natural Resources Economics, Anddison Wesley.

USEPA, 2007, Continuous Emissions Monitoring System, camddataandmaps.epa.gov/gdm/.

USPEA, 2008, Clean Air Markets, www.epa.gov/airmarkets/progsregs/cair/faq-10.html