CHALLENGES IN QUANTIFYING OPTIMAL CO_2 EMISSIONS POLICY: THE CASE OF ELECTRICITY GENERATION IN FLORIDA

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Abstract

Implementing public policy without understanding its economic impacts can be costly and unproductive. This problem is paramount when a price of carbon dioxide (CO_2) emissions is considered as a vehicle for abatement. The United States Congressional Budget Office, Environmental Protection Agency, and Department of Energy's Energy Information Administration have all released their estimates of the macro-economic impact of various proposals for environmental legislation. The focus of these studies is on the level of output variables such as the amount of CO_2 emissions, the cost of emissions allowances, and the broad impact of increased electricity prices, rather than on the marginal effects of policy change. This paper utilizes a model that simulates the dispatch of electric generating units in the state of Florida under various prices for CO_2 emissions, and analyzes the challenges that may arise in the determination of optimal emissions abatement policy. At relatively low CO_2 prices emissions levels decrease as CO_2 prices increase. However, once this initial reduction has been achieved, further increases in CO_2 prices may do little to decrease emissions until a 'critical point' has been achieved and more coal generation is displaced by natural gas. This paper demonstrates how the incremental cost of abatement curves may intersect with a CO_2 tax at many levels of abatement, allowing for different characterizations of the 'optimum'. Therefore, agreement on the marginal costs and the marginal benefits of CO_2 abatement can be seen as a necessary condition for the determination of an optimal level of abatement, but not a sufficient one.

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I. Introduction

Questions regarding the economic impact of carbon dioxide (CO_2) emissions continue to accompany any discussion regarding the imposition of emission limits. However, most of these discussions focus on only one side of the relationship between CO_2 prices and emissions levels. That is, they attempt to quantify the resulting CO_2 price implied by an exogenous level of emissions, or the emissions level that would result from a given emissions price. Studies that take either price or emissions level as exogenous may not offer insight into the question of the optimal level of abatement[1], by ignoring the interaction between them. This paper considers the effects of a range of CO_2 prices on both abatement levels and costs, thereby informing an analysis of the average cost curves for emissions abatement, which provides insight into the unusual behavior of the marginal costs of abatement. Such insight is necessary in any discussion of optimal levels of emissions abatement.

In July of 2007, Florida Governor Charlie Crist hosted the historic "Serve to Preserve: A Florida Summit on Global Climate Change," in Miami. This summit brought business, government, science, and stakeholder leaders together to discuss the effects of climate change on Florida and the nation. On the second day of the summit, July 13, the Governor signed three Executive Orders to shape Florida's climate policy. Order 07-126 mandated a 10% reduction of greenhouse gas emissions from state government by 2012, 25% by 2017, and 40% by 2025. Order 07-127 mandated a reduction of greenhouse gas

[1] Targeted levels of emission reduction are frequently alliterative, such as 50% by 2050.

emissions from the state of Florida to 2000 levels by 2017, 1990 levels by 2025, and 20% of 1990 levels by 2050. Finally, Order 07-128 established the Florida Governor's Action Team on Energy and Climate Change and charged the team with the development of a comprehensive Energy and Climate Change Action Plan.

On June 25, 2008, Florida House Bill 7135 was signed into law by Governor Crist, creating Florida Statute 403.44 which states: "The Legislature finds it is in the best interest of the state to document, to the greatest extent practicable, greenhouse gas emissions and to pursue a market-based emissions abatement program, such as cap and trade, to address greenhouse gas emissions reductions." The initial focus of the state government is to place a cap on the amount of carbon dioxide emitted by the electric power generation sector.

In cooperation with the State of Florida's Department of Environmental Protection, the Florida legislature commissioned a study of the economic impacts on the state of such a program. This paper utilizes a version of the model[2] constructed for that study (Kury and Harrington 2010) to simulate the dispatch of electric generating units in the state of Florida over a range of CO_2 prices. The analysis concludes that the marginal cost of abatement curve may not be well-behaved, implying several points where the marginal costs of abatement are equal to the marginal benefits. This behavior can complicate the question of an optimal level of CO_2 abatement.

The remainder of this paper is organized as follows: Section II provides a review of the literature on the economic effects of CO_2 emissions, Section III describes the model of economic dispatch, Section IV describes the data sources utilized, Section V discusses

[2] Both the underlying code and the input assumptions have been updated.

the mechanics of the simulation, Section VI discusses the model results, and Section VII provides some concluding remarks.

II. Literature Review

Nordhaus (1980) is credited as being the first to derive optimal levels of CO_2 emissions, in a model of the CO_2 cycle and CO_2 abatement. He further discussed a model of the effects of CO_2 buildup in the environment and the intertemporal choice of consumption paths, and ended with suggestions regarding how to compare control strategies. He also identified three empirical issues with policy implementation: the problem that CO_2 emission is an externality across space and time, whether to control CO_2 emissions with quantities or prices, and the effects of uncertainty regarding the costs and benefits of CO_2 abatement. Further theoretical research has explored aspects of the Nordhaus model, such as Goulder and Mathai (2000), who characterized optimal carbon taxes and CO_2 abatement under different channels for knowledge accumulation, under cost-effectiveness and benefit cost criterion.

The bulk of the literature consists of *ex-ante* studies of proposed levels of emissions abatement. In the United States, the Congressional Budget Office (CBO), Environmental Protection Agency (EPA), and the Department of Energy's Energy Information Administration (EIA) have all studied the effects of legislation proposed in the House of Representatives and the Senate. These analyses typically treat the levels of emissions proposed in the bills as exogenous, and attempt to determine their economic impact. For example the EIA analysis of the American Power Act of 2010 concluded that CO_2 emissions prices in the Base Case would reach \$32 per ton in 2020 and \$66 per ton in

2035. This analysis is limited in its ability to offer insight into policy alternatives, however.

Studies on the regional economic impact of CO_2 pricing on the market for electric generation have been performed for the ERCOT region in Texas[3], as well as the PJM region in the Northeastern United States[4]. Examining the conclusion for those two studies shows how the relative carbon intensity of the electric generation fleet can have a marked impact on the economic effects of CO_2 pricing. Pennsylvania relies on more coal-fired generation, and therefore the impact of a $1 increase in carbon prices results in a $0.70/MWh increase in wholesale electricity prices. Texas, which relies more on natural gas sees its wholesale prices increased approximately $0.50/MWh with a $1 increase in CO_2 prices. Similar analyses have been conducted for the European market. Honkatukia et. al (2006) studied the degree to which allowance prices in the European Union Emissions Trading System for CO_2 get passed through to the wholesale prices in Finland, and concluded that 75% to 95% of the price change is passed through to the spot price.

A comparative analysis was conducted by Newcomer et al. (2008) who modeled the short run effects of a range of CO_2 prices on the price of electricity and level of carbon dioxide emissions in three regions of the United States, but the determination of an optimal level of abatement was beyond the scope of their work.

The literature on the social costs of CO_2 emissions presents a diverse range. The Contribution of Working Group II to the Fourth Assessment Report to the Intergovernmental Panel on Climate Change (2007) cited the results of a survey of 100 estimates of the social cost of CO_2 that reported a range from -$3 per ton to $95 per ton.

[3] http://www.ercot.com/content/news/presentations/2009/Carbon_Study_Report.pdf
[4] http://www.pjm.com/documents/~/media/documents/reports/20090127-carbon-emissions-whitepaper.ashx

This survey was taken from Tol (2005), which reported a mean of $43 per ton (in 2005$) of carbon with a standard deviation of $83 per ton of carbon[5] in the peer-reviewed studies. In its modeling, the Interagency Working Group on the Social Cost of Carbon, United States Government (2010), uses values from $5.70 to $72.80 (in 2007$) for the social cost of CO_2 in 2015, and $15.70 to $136.20 for 2050. Anthoff and Tol (2013) analyze the factors that affect the uncertainty in the social cost of carbon and find that the influence of parameters changes depending on the time scale of the analysis or the region considered. They also find that some parameters are more certain than others. Ackerman and Stanton (2012) demonstrate that with high climate sensitivity, high climate damage, and a low discount rate, the social cost of CO_2 could be almost $900 per ton in 2010.

III. Model of Economic Dispatch

The problem of least-cost economic dispatch of a group of *n* electric generating units is to minimize the aggregate costs required to provide the amount of electricity demanded by end-users in each hour. The costs to produce this electricity will be driven by the type of generating unit, its thermal efficiency[6], the variable costs required to operate and maintain the unit, and the price of its fuel. For each hour, the problem can be stated:

$$\min_{G} \sum_{i=1}^{n} G_i \{[(CO2_i * Emit\$) + Fuel\$_i] * HeatRate_i + O\&M\$_i\}$$

subject to the constraints:

$$\sum G_i \geq L$$

[5] These figures convert to $11.62 and $22.43 per ton of CO_2, respectively.
[6] The thermal efficiency of a power plant is the rate at which it converts units of fuel to a given unit of electricity. This is typically called the heat rate of a power plant, and all else equal, a lower heat rate is preferred to a higher one.

$$G_i \leq C_i \; \forall i$$

where:

G_i	MWh generated by the *i*th generating unit
C_i	Maximum hourly generating capacity in MWh of the *i*th generating unit.
L	Electricity demand by consumers in MWh
$CO2_i$	Tons of CO_2 emitted per MMBtu of fuel consumed by the *i*th generating unit
Emit$	Emissions cost per ton of CO_2
$Fuel\$_i$	Cost of fuel per MMBtu consumed by the *i*th generating unit
$HeatRate_i$	Heat rate of the *i*th generating unit in MMBtu of fuel required to produce one MWh of electricity
$O\&M\$_i$	Hourly operation and maintenance expenses of the *i*th generating unit in $/MWh

Without a price for emitting CO_2, the value of *Emit$* is zero and the amount of CO_2 emitted by that generating unit does not enter the dispatch equation. With a positive value for *Emit$*, the total cost of emissions is driven by the operating efficiency of the generating unit and by the type of fuel utilized, as some generating fuels emit relatively more carbon dioxide when burned. Such fuels, which include coal and petroleum coke, are often referred to as “dirty” fuels. Fuels that emit relatively less carbon dioxide when burned, such as natural gas, are referred to as “clean” fuels. Therefore, the price of emissions may necessitate the switch from a dirtier generating fuel to a cleaner one by an individual generator capable of burning more than one type of fuel, or may lead to a generator that burns a dirtier fuel being replaced by a generator that burns a cleaner fuel.

The strategies to reduce emissions from the electric generation sector are limited in the short run. Generators can adjust the types of fuels that they use, known as fuel-switching, or reduce the amount of electricity that they produce. In the long run, the generator's options expand to strategies such as improving the heat rate of existing power plants (thus reducing fuel consumption), construction of new power plants that produce electricity while emitting less (or no) carbon dioxide, or developing and exploiting technologies that captures a portion of the carbon dioxide emitted. The model utilized in this paper allows for both short run and long run strategies.

The determination of the optimum hourly unit dispatch is conducted in two stages. First, the hourly operating cost is minimized for each available generating unit. For units with the capability to burn different fuels, the cost and emissions rate of each fuel are considered and the least-cost alternative is selected. Second, all of the generating units are ordered from lowest cost to highest, and the units with the lowest hourly costs are dispatched until the hourly electric loads are met.

IV. Data Sources

Data on the hourly marginal costs for individual generating units is considered proprietary, so these costs must be estimated. Data for individual generating units, such as summer and winter generating capacity, the type of generating unit, and fuel sources, are available from the EIA Form 860 (Annual Electric Generator Report) and Form 861 (Annual Electric Power Industry Database) databases. Data on generating unit operating efficiency, such as heat rate, are available from EIA Form 423 (Monthly Cost and Quality of Fuels for Electric Plants Data) filings. The heat rate data utilized in this simulation represents the annual average heat rate for each generating unit. Some unit level operating data, such as variable operating and maintenance expenses, are available from utility responses to the Form 1 (Annual Report of Major Electric Utility) required by the Federal Energy Regulatory Commission (FERC). Other operating data is derived from industry averages published by the EIA for use in its Annual Energy Outlook. Unit-specific operating and contract data[7] as well as long term load forecasts, are available from the Regional Load and Resource Plan published by the Florida Reliability Coordinating Council. Actual hourly loads are available from utility responses on Form 714 (Annual Electric Control and Planning Area Report) to the FERC. Data for planned generating units are available from the FRCC Regional Load and Resource Plan. Projected fuel prices and levelized costs of new generation are taken from the 2013 Annual Energy Outlook published by the EIA.

V. Model Operation

Within each month of a given run, the model first determines the order in which the generating units will be dispatched to meet electric load, often called the generation stack, and then dispatches the generation stack against the monthly load shape on an hourly basis, using equation (1) in Section III.

When dispatching each unit, the model discounts each unit's production capacity by the unit's availability factor. This availability factor reflects distinct operating characteristics of different types of generating units. Electrical generation for different types of units may or may not be controlled by the operator of the unit. For a unit that burns fossil fuels, if the power plant is running and has fuel available, it will generate electricity. These types of units are also called dispatchable units. For a unit that relies on the sun or the wind to generate electricity, however, that power plant will not produce electricity if the sun is not shining or the wind is not blowing. These types of units are called nondispatchable units.

[7] Contract data includes power purchased from other states under long term contracts. As a result, the costs associated with these contracts are sunk, and their marginal cost of dispatch is zero.

For nondispatchable units, the availability factor reflects the amount of time that the sun is shining or the wind is blowing. For dispatchable units, this availability factor reflects the times when the unit is available to generate. This methodology, often called a "derate" methodology, accounts for the unit being unavailable due to either a planned or unplanned outage. Ideally, two factors would be used to reflect unit availability. The first would reflect planned unit outages, most commonly for routine maintenance. The second factor would reflect unplanned, or forced, outages; the instances where a unit breaks down unexpectedly. However, individual unit outage schedules are proprietary and dynamic. To ameliorate these modeling limitations, this availability factor is employed.

The long run strategies employed by the model consider the decisions to build new power plants. The model can either be allowed to build new generating units only when they are necessary to serve electric load, or might be allowed to build new units opportunistically, that is, when the wholesale price of electricity is sufficient to allow the new units to earn a profit. The former approach may not induce generation sufficient to reach more aggressive emission reduction targets, as the composition of the generation fleet is more static, while the latter approach may lead to the problem of stranded investment. Because the construction of new generating units in Florida is regulated through a determination of need proceeding at the state Public Service Commission[8], the former approach has been modeled in this analysis. The opportunistic approach was also modeled, but yielded similar results. Changes in the outlook for natural gas prices limited the emissions reductions that could be achieved even with the opportunistic approach, however. In Kury and Harrington (2010), a carbon price of $90 per ton was sufficient to induce a change in construction to zero-emitting technologies (nuclear and biomass),

[8] Florida Statutes 403.519

while the latest prices for natural gas and generating technologies now require a carbon price of $135 per ton to induce the same behavior.

VI. Model Output

During its execution, the model tracks the electricity production for each unit, as well as the units of fuel burned, the total dispatch costs, and the carbon emissions. These output variables are be aggregated by utility, type of plant, fuel type, and plant vintage.

The aggregate model output consists of matched sets of emissions prices, emissions levels, and the volume of each generating fuel burned for each model year. Therefore, each level of emissions in a particular year implies a price of emissions and a fuel mix, and vice versa. In that manner, the model determines the price of emissions and mixture of generating fuels that correspond to each level of carbon dioxide emissions, for each compliance year in the analysis. Further, it also computes the effects of different levels of emissions (and the resulting emissions prices) to allow the characterization of the marginal effects of the emissions policy.

The model was run for the years 2012-2025, varying the CO_2 price from $0 to $100 per ton, and the change in several output variables is presented. The first variable is the change associated with the real incremental cost component of electricity production, shown in Figure 1.

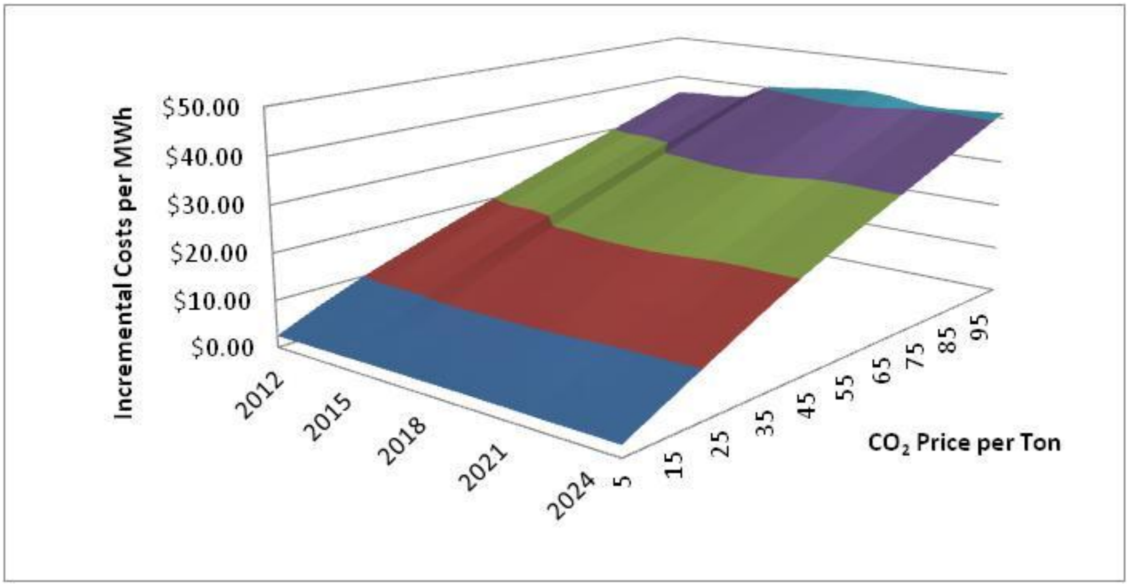

Figure 1. Real ($2010) Incremental Cost of Electricity by Year and Emissions Price

While the relationship between emissions prices and incremental cost does change slightly as we look further into the future, the relationship between emissions prices and incremental cost is fairly stable, as a $1 increase in emissions prices tends to raise the price of electricity in Florida by approximately 50¢ per MWh, or about $6 per year for a family that uses 1000 kWh per month. This effect drops to about 40¢ per MWh as emissions prices increase to $100 per ton. The magnitude of the effect of CO_2 prices on incremental cost reflects the relative carbon intensity of the generating units utilized to produce electricity, so a decrease in the effects of an emissions price as the emissions per MWh of electricity decreases is expected.

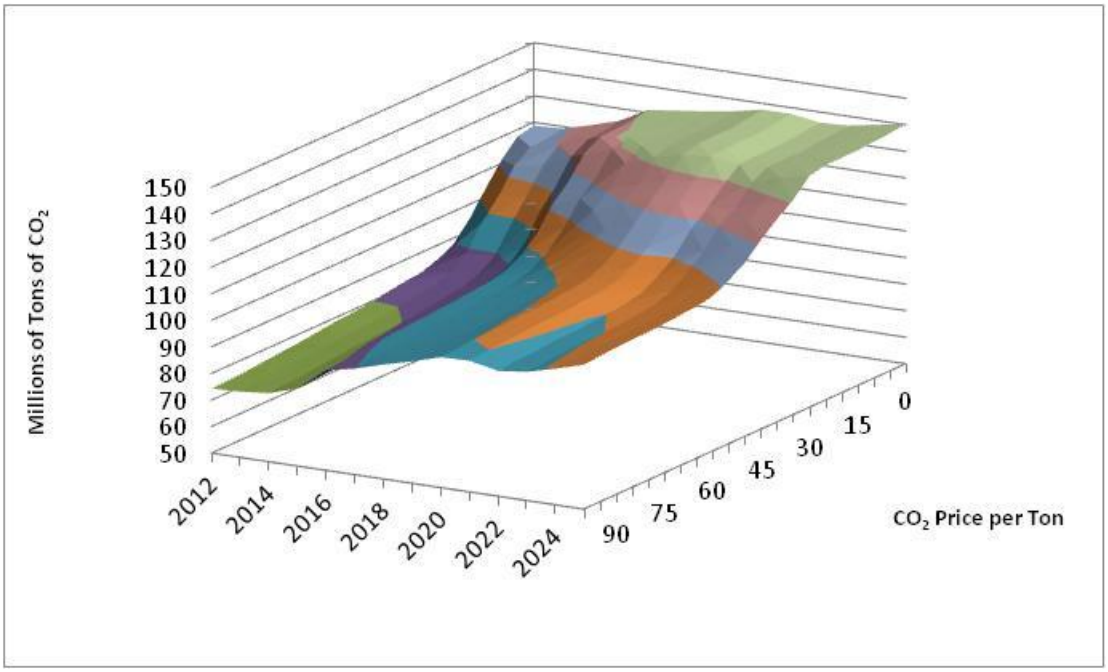

Figure 2. Emissions by Year and Emissions Price

Figure 2 illustrates the effects of carbon dioxide emissions prices on the emissions of the electric generating sector. Emissions levels are initially reduced 2-3% under relatively low emissions prices. This is primarily due to the displacement of some petroleum coke and inefficient coal generators as a source of electricity in Florida. However, emissions levels then reach a plateau, whose magnitude varies with the year, during which increasing the price of emissions has relatively little effect on overall emissions levels. Once emissions prices exceed a critical value, however, a rapid decline in emissions levels occurs. This decline in emissions occurs at $15 per ton in the short run, as coal-fired generation is quickly displaced by natural gas. The 'flat spots' in the surface, however, are cause for concern for policymakers. These areas are regions in which costs are increasing for consumers[9], in the form of higherrealized costs, but with little

[9] As seen in Figure 1.

corresponding decrease in emissions. Consumers are thus paying higher costs without any concurrent benefit.

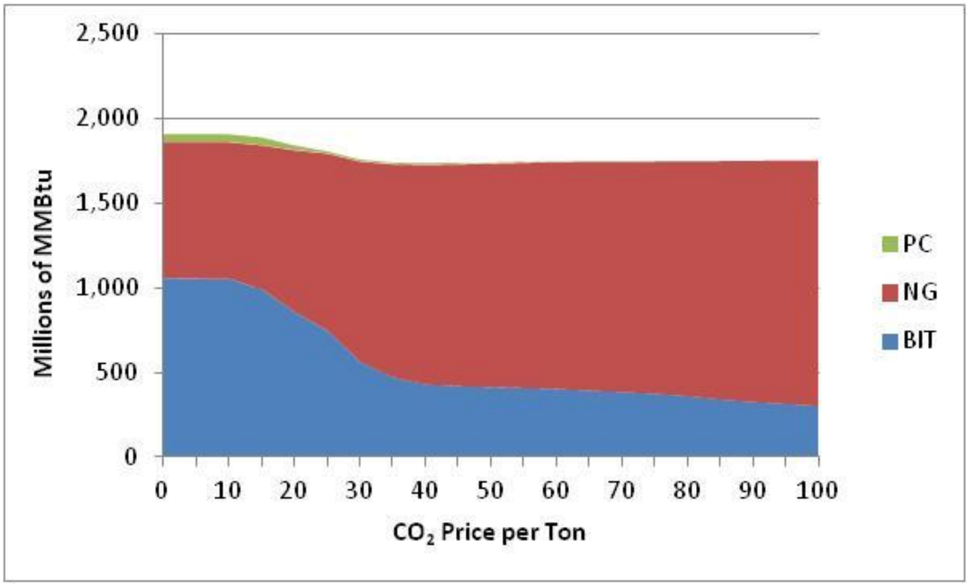

Figure 3. Fuel Consumption in 2015

Figure 3 illustrates the amount of coal (BIT), natural gas (NG), and petroleum coke (PC) burned during the simulation of 2015. These results provide insight into the shape of the emissions surface. Initial reductions in emissions levels are modest at CO_2 prices of up to $10. Note that since electricity generators in Florida emit roughly 110 millions tons of CO_2 annually, a CO_2 price of $10 per ton implies that consumers are paying roughly $1 billion yet seeing relatively little reduction in CO_2 emissions. At CO_2 prices of $15, displacement of coal and petroleum coke accelerates and emissions levels drop quickly. Once an CO_2 price of $30 per ton is reached, initial coal consumption has been reduced by 50% and the displacement of the remaining coal fired capacity continues at a much lower rate. As the price of natural gas increases relative to coal prices, this tipping point where natural gas begins to displace more coal generation increases as well.

The results shown in Figures 1 and 2 can be consolidated to construct the average cost curves for emissions abatement in a given year. Figure 4 shows these average cost curves for four selected years of the simulation.

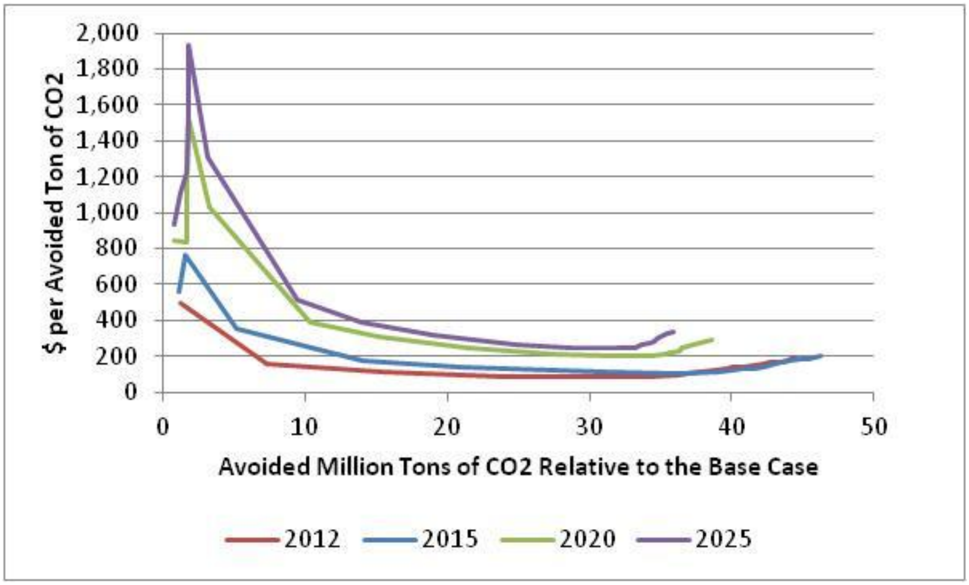

Figure 4. Average Cost of Abatement Curves

While the marginal cost of abatement cannot be observed from a discrete model, some behavior of the marginal cost curves can be inferred from the shapes of these average cost curves. The marginal cost curves for the years 2015, 2020, and 2025 clearly cross the average cost curve multiple times, as those average cost curves contain local as well as a global minima. Therefore, the marginal benefits curve for emission abatement, even if it is itself well-behaved, may intersect the marginal cost curve at more than one abatement level. Even though the marginal cost of abatement cannot be observed in a discrete model, an approximation of the marginal cost curve, the incremental cost curve, can be calculated. To illustrate this phenomenon, the average and incremental costs of abatement for 2015 are shown in Figure 5.

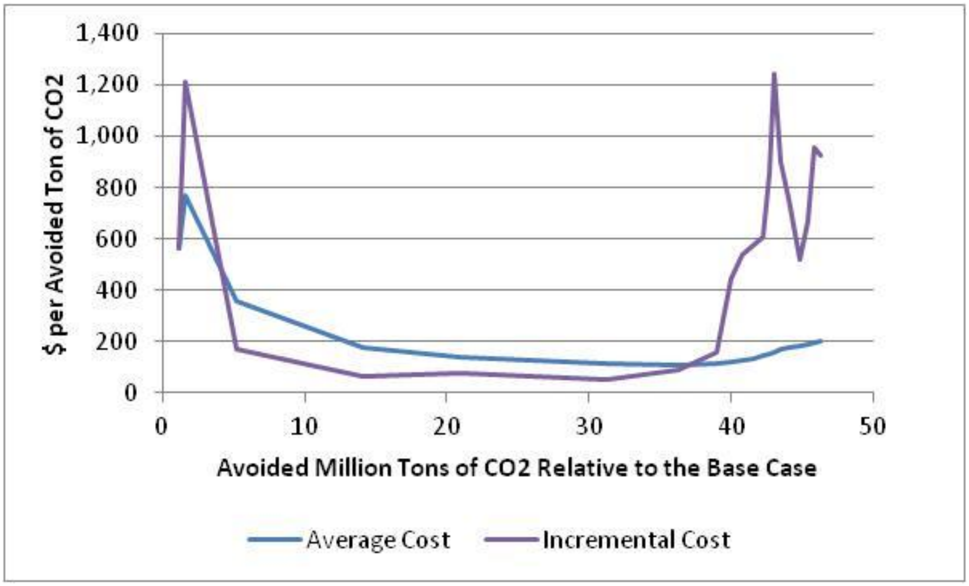

Figure 5. Average and Incremental Cost of Abatement Curves for 2015

The incremental cost curve for 2015 is clearly not well behaved, sloping upward over several levels of abatement. As discussed in Section II, there is considerable uncertainty surrounding the social cost of CO_2 abatement. If a CO_2 tax of $700 per ton is established, a value at the upper range of the social cost of CO_2 established in the literature, the tax would be equal to the incremental cost of abatement at approximately 1 million, 42 million, and 45 million tons of avoided CO_2. This phenomenon is illustrated in Figure 6.

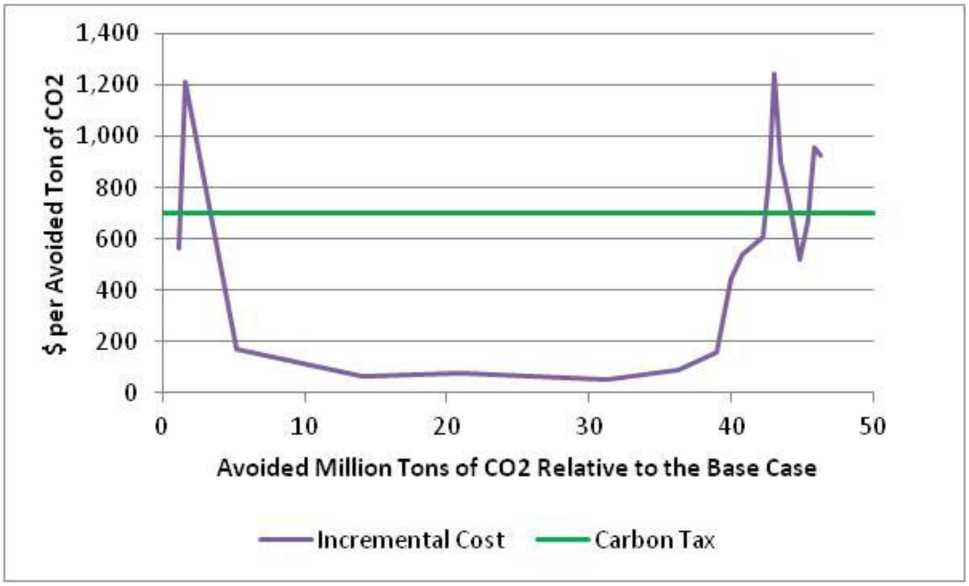

Figure 6. Multiple Abatement Equilibria at a Carbon Tax of $700

If the tax were equal to $70 per ton, a level within the range of the social cost of CO_2 established by the Interagency Working Group of the United States Government, it would be equal to the incremental cost of abatement at approximately 18 million and 34 million tons of avoided CO_2. This is illustrated in Figure 7.

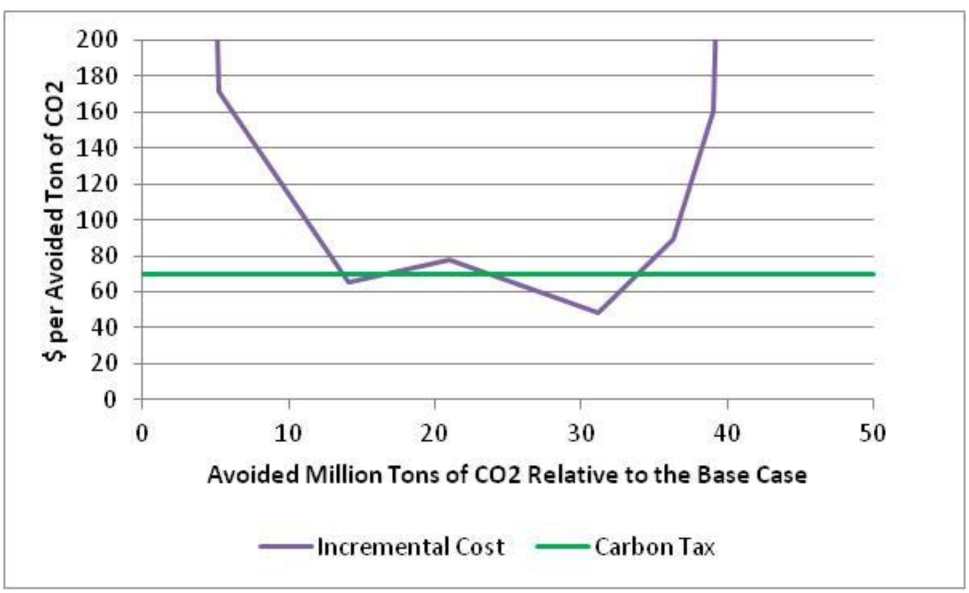

Figure 7. Multiple Abatement Equilibria at a Carbon Tax of $70

If the price of CO_2 were set below this curve, at say $40 per ton, the utilities would simply pay the tax and continue to emit at current levels. Any reduction in emissions would be the result of what the taxing authority chooses to do with the revenue. Note that this uncertainty in the emissions level implied by the equality of marginal costs and marginal benefits in Figure 7 is economically significant. The total emissions for the electricity generating sector in Florida is roughly 110 million tons annually. The 16 million ton difference between these two levels that could be considered optimal is roughly 15% of total emissions. Therefore, a policy aimed at reducing emissions by a stated percentage[10] could be over- or under-achieved by a significant amount. The challenge for policymakers is that when the optimal level of CO_2 abatement is considered, using the criteria of equating marginal costs with marginal benefits, there may not be a single optimum level. Therefore, even if global leaders were to agree on the marginal costs and marginal benefits of CO_2 abatement, an accomplishment that is likely difficult to achieve, there is still the potential to disagree on the optimum level. Therefore, the quantification of the marginal benefits and the marginal costs of emissions abatement are necessary, but not sufficient, conditions for the identification of an optimum. This complicates either of the types of policy instruments used to control emissions levels. This would make it difficult to agree on the level of an emissions cap, if that method of regulation is implemented. Further, if emissions control through a carbon tax is considered, it may not result in the desired level of emissions abatement. Therefore, if a specific level of CO_2 abatement is desired by policy makers, the implementation of an emissions cap may be the only reliable way to achieve it.

[10] For example, a 30% reduction by 2030.

VII. Conclusions

It is easy to find discussions of government-imposed carbon dioxide abatement targets and the emissions prices that result from these targets, but the literature on discussions of policy alternatives or the establishment of optimal emissions abatement is not well-developed. Since emissions abatement carries a cost to the consumer, however, it is important to ensure that those costs are commensuarate with the benefits that consumers are receiving from this abatement policy.

This paper presents the results of an analysis of the units used to generate electricity in Florida and the marginal effects of carbon prices on their dispatch. Using the operating characteristics of Florida's generating units, and a least-cost economic dispatch model, this paper analyzes the effects that various emissions prices (and their concurrent emissions levels) have on Florida's level of carbon dioxide emissions and the amounts of fuel consumed for electric generation. We find that at relatively low emissions prices emissions levels decrease as fuel sources such as petroleum coke and coal burned in less efficient plants are displaced. Once this initial reduction has been achieved, further increases in carbon prices may do little to decrease emissions until a "critical point" has been achieved, and most coal generation can be displaced by natural gas. These results suggest that the marginal effects of emissions prices may vary greatly with the level of emissions abatement and the fundamental characteristics of the market.

The question of what constitutes optimal emissions abatement policies is complicated by the potential for the marginal cost of abatement curves to oscillate. This paper demonstrates how the incremental cost of abatement curves may intersect with a CO_2 tax at many levels of abatement, allowing for different characterizations of the 'optimum'. Therefore, agreement on the marginal costs and the marginal benefits of CO_2

abatement can be seen as a necessary condition for the determination of an optimal level of abatement, but not a sufficient one.

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