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 U, S. 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. These studies focus on levels of 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 addresses this deficiency by utilizing a model that simulates the dispatch of electric generating units in the state of Florida and demonstrates that the incremental cost of abatement curves may fluctuate and may not be well-behaved, and that this complicates identifying an 'optimal' level of abatement and how it may be achieved. Agreement on the marginal costs and 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.

Keywords: Optimal CO_2 abatement policy, Electric utilities, Climate change

JEL Classification: L94, Q54, Q58

CHALLENGES IN QUANTIFYING OPTIMAL CO_2 EMISSIONS POLICY:
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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 cost curves for emissions abatement and providing insight into the unusual behavior of the marginal costs of abatement. Such insight is necessary in any discussion of the optimal levels of emissions abatement.

On May 5, 2014, the World Bank issued the draft statement "A Call for Countries & Companies to Support a Price on Carbon"[2] in which it stressed "the importance of putting a price on carbon to help limit the increase on global mean temperature to two degrees Celsius above per-industrial levels". The policy direction is clear, but the means for implementation are likely to be less so. The purpose of this analysis is to explore the

[1] Targeted levels of emission reduction are frequently alliterative, such as 50% by 2050.
[2] http://www.worldbank.org/en/news/feature/2014/05/05/supporting-a-price-on-carbon

complicated relationship between the imposition of a price on carbon, and the resultant effect on emissions.

Widespread interest in the potential harm caused by carbon dioxide emissions began in the 1970s, and formally entered public policy debates when Woodwell et al. (1979) submitted “The Carbon Dioxide Problem” to the United States Senate Subcommittee on Governmental Affairs. In 1988, the World Meteorological Association and the United Nations Environment Program created the Intergovernmental Panel on Climate Change, to prepare assessments on all aspects of climate change in order to formulate realistic response strategies. Since then, public policy regarding the reduction of CO_2 emissions has focused on stated reductions, and economic analysis has focused on the impact of these reductions. That is, the degree of emissions reduction precedes the analysis. Examples include the negotiated reductions of the Kyoto Protocol in 1997 and the American Clean Energy and Security Act of 2009 (also known as the Waxman-Markey bill), which imposed a series of emissions reductions through 2050.

This approach flies in the face of informed public policy. Consider an arbitrary reduction policy, a 50% reduction in CO_2 emissions by 2050. There are likely to be abatement costs associated with this reduction, and these costs have economic consequences. But what if a 70% reduction could be achieved at basically the same marginal cost? What if a 48% reduction would have a significantly lower marginal cost? Could these policy alternatives be superior to the stated objective? But the existence of these policy alternatives is not even adequately addressed within the current system. Political rhetoric has superseded any discussion of the optimal level of CO_2 abatement. For an economist, the concept of an optimal level is clear; it is the point at which the marginal benefit of reduction is equal to the marginal cost. But the question of CO_2 emissions is sufficiently complex that the marginal cost and marginal benefit curves may not be enough to characterize an optimum.

This paper estimates the marginal cost of abatement using a model of electricity generation in Florida. It finds that the marginal cost curve is not well behaved. More specifically the model shows marginal cost rises rapidly at low levels of abatement and then nearly flattens over a broad range of abatement amounts before rising steeply again. This shape implies that the marginal cost of decreasing emissions by 5%, for example, may be nearly the same as a 50% reduction. For cost-benefit purposes, the optimal amount of abatement may change greatly with small changes carbon prices. Furthermore, the location of the marginal cost curve is sensitive to fuel prices. For example, even though prices for natural gas are relatively low by historical standards, the volatility is sufficient to make the marginal cost of abatement to swing widely, with the result that the optimal amount of emissions can change greatly from month to month. Finding the optimal amount of abatement is further complicated once it is recognized that emissions are determined as much by the interaction of supply and demand in the market for electricity as in what we might think of as the market for abatement. That is to say, when the price of $CO_2$is sufficiently high to potentially reach the sharply upward sloping portion of the marginal cost curve for abatement, the resulting increase in energy prices can lead to sufficient decreases in the quantity demanded for electricity that the actual amount of abatement is large compared to the amount that would have occurred at a slightly lower price of CO_2. The result of this interaction of the electricity and abatement “markets” is that the marginal cost of decreasing carbon emissions can both rise and fall as more emissions are abated even if fuel prices are stable.

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 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 type of analysis is limited in its ability to offer insight into policy alternatives, however, as it doesn't consider alternate levels of emissions.

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.

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[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

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. 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.

In July of 2007, Florida Governor Charlie Crist hosted the historic "Serve to Preserve: A Florida Summit on Global Climate Change," in Miami. On the second day of the summit, July 13, the Governor signed three Executive Orders to shape Florida's climate policy. Order 07-126 followed a familiar pattern: mandating a 10% reduction of greenhouse gas emissions from state government by 2012, 25% by 2017, and 40% by 2025. Subsequently Order 07-127 mandated a reduction of greenhouse gas 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

[5] These figures convert to $11.62 and $22.43 per ton of CO_2, respectively.

Energy and Climate Change and charged the team with the development of a comprehensive Energy and Climate Change Action Plan.

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, some of the results of which were published in Kury and Harrington (2010). This paper utilizes an updated version of the model[6] constructed for that study 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 may not be well-behaved, implying considerable volatility in what might be considered 'optimal' levels of abatement or carbon pricing. This behavior can complicate the question of an optimal level of CO_2 abatement and how it might be achieved in practice.

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[7], 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:

[6] Both the underlying code and the input assumptions have been updated.
[7] 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.

$$\sum G_i \geq L$$

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

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. In the short run, generating units capable of fuel-switching are allowed to change fuels on a monthly basis. In the long run, new generation is constructed whenever the peak load of the system augmented by a 15% reserve margin exceeds the available generating resources. The model uses data on the levelized cost of new generating resources published by the EIA in its Annual Energy Outlook[8] to select the least expensive generating resource. Since the state of Florida requires a determination of need proceeding before the Florida Public Service Commission[9], this is a reasonable approximation of the process for new generation in the state.

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.

The model utilizes a few simplifying assumptions. Transmission constraints are not explicitly modeled, but certain units have been designated "reliability must run" units

[8] See http://www.eia.gov/forecasts/aeo/electricity_generation.cfm for an example from 2014
[9] Florida Statutes 403.519

necessary to maintain reliability of the electricity grid. These units will always be dispatched, and simulates the state's intra-state limitations. Florida also imports power from Georgia and Alabama through either direct power plant ownership or purchased power contracts. The terms of the purchased power contracts require payment regardless of whether the electricity is utilized[10], so the contract is always dispatched. Finally, start-up costs are not modeled for any of the generating units. The data on these costs is considered sensitive, and therefore not published. Cullen (2013) estimated these costs econometrically, but his technique relied on prices and generation unit dispatch data in the ERCOT market, and this data is not available for Florida.

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-

[10] These are so-called "take or pay" contracts.

specific operating and contract data[11] 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).

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.

[11] 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[12], 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),

[12] 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.

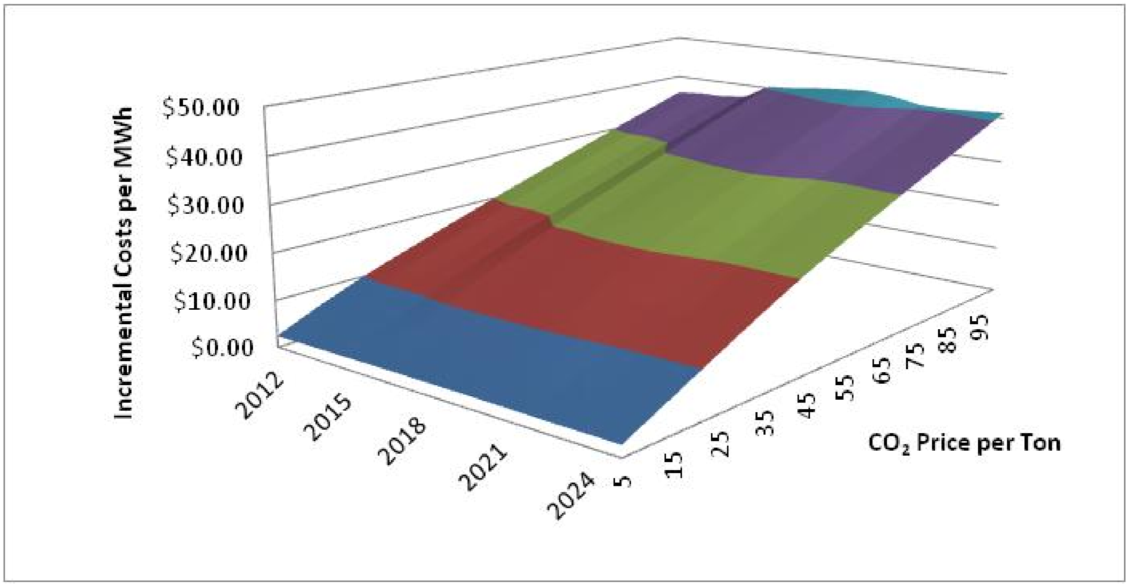

Figure 1. Real ($2010) Incremental Cost of Electricity by Year and Emissions Price

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 price increase is due not only to the increase in emissions price, but the cost consequences of utilizing more expensive generation, if not for the emissions tax. 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.

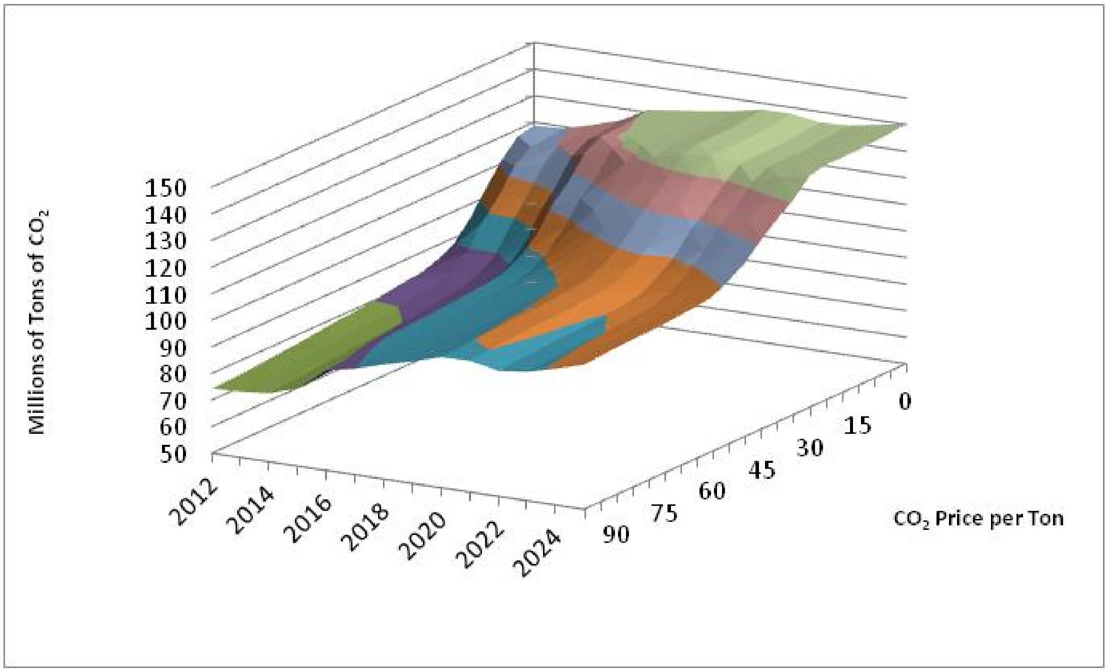

Figure 2. Emissions by Year and Emissions Price

Figure 2 illustrates the effects of carbon dioxide emissions prices on the emissions of the electric generating sector. Emissions levels are initially reduced about 1% 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 width varies by 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[13], in the form of higher realized costs, but with little corresponding decrease in emissions. Consumers are thus paying higher costs without any concurrent benefit of CO_2 reduction.

[13] As seen in Figure 1.

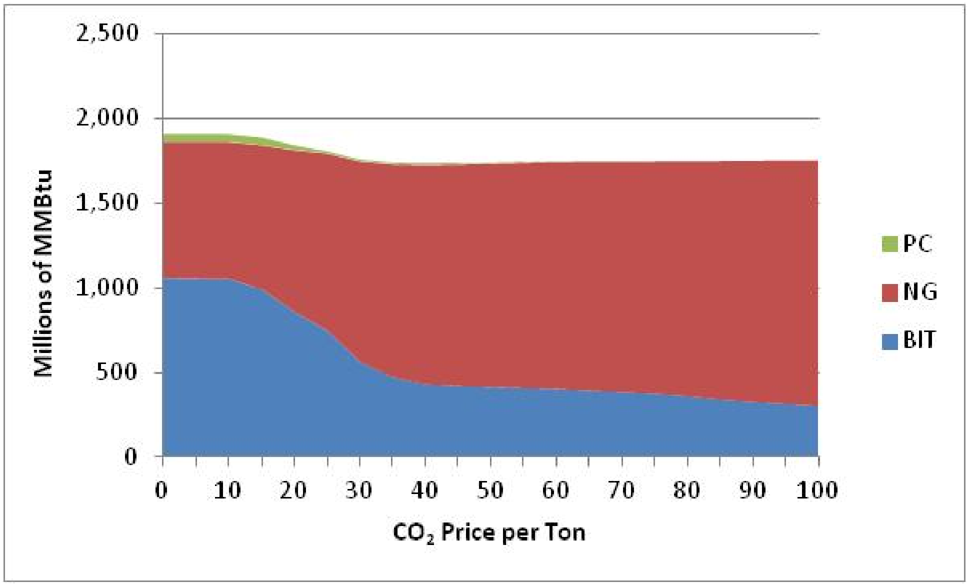

Figure 3. Fuel Consumption in 2015

Figure 3 illustrates the amount of coal (BIT), natural gas (NG), and petroleum coke (PC) burned during the simulation of 2015. These results provide some 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 a 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.

This phenomenon, where costs increase in a linear fashion with CO2 prices, but emissions decrease in an irregular fashion, leads to marginal cost curves that might not be considered well-bahaved. The marginal consumer cost of abatement cannot be observed from a discrete model, but an approximation of the marginal cost curve, the incremental consumer cost curve, can be derived. Figure 4 shows the incremental abatement cost curve, just the cost of switching fuels, for the year 2015.

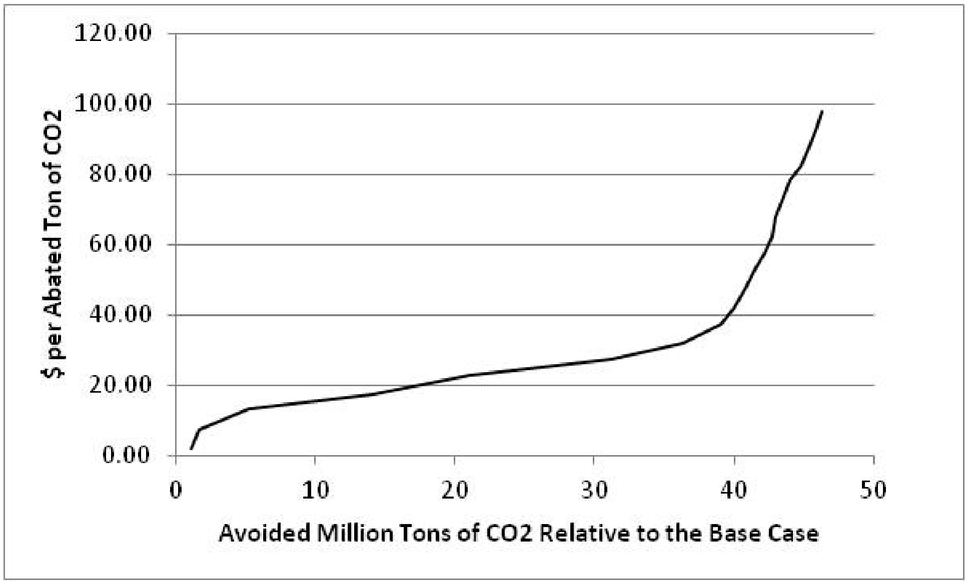

Figure 4. Incremental Abatement Cost Curve for 2015

The incremental costs of very low levels of emissions abatement initially increase, as the utilities' behavior changes little. Since very little fuel switching is occurring, emissions are largely unchanged, and incremental costs per ton of abated CO2 increase rapidly. Once the price of CO2 is sufficient to induce fuel switching, significant abatement occusrs and the incremental costs increase slowly. Once about 40 million tons of CO_2 have been abated, most of the potential for fuel switching is exhausted and incremental costs rise rapidly again. This illustrates the first challenge in implementing emissions control policy. Weitzman (1974) proves that if the marginal cost curve is steep, that there is not much difference in regulating with prices or quantities. However, if marginal costs are relatively flat, then it is much riskier to regulate with prices. A shift of the marginal cost right or left (caused by, in the short run, a change in the relationship between natural gas and coal prices) can lead to a violent swing in CO_2 emissions. With the marginal costs in Figure 4, a \$20 carbon tax would yield approximately 18 million tons of CO_2 abatement.

To illustrate the volatility of this abatement, consider a second run of the model where natural gas prices have doubled. For 2015, this means an increase in gas prices from roughly \$4.00 per MMBtu to roughly \$8.00 per MMBtu. The new incremental cost of abatement curve is illustrated in Figure 5.

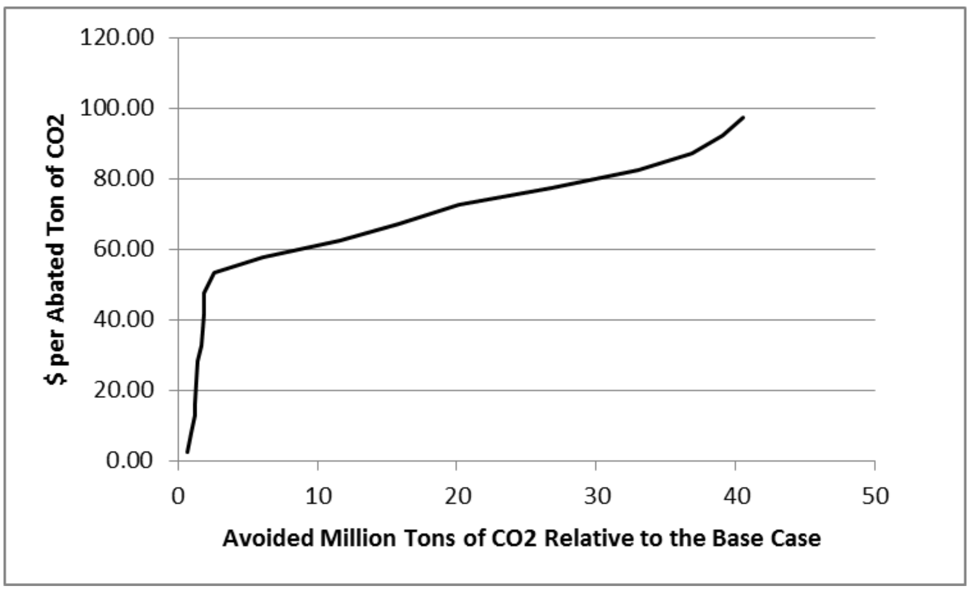

Figure 5. Incremental Abatement Cost Curve for 2015 with High Gas Prices

With an increase in the price of natural gas relative to coal, the CO_2 price necessary to induce fuel switching has increased as well. Signficant reductions in CO_2 emissions do not begin to occur until the price per ton of CO_2 reaches \$50 per ton. As a result, the emissions reduction realized with a \$20 carbon tax is only about 1 million tons. This is a decrease of approximately 17 million tons from the base case. While 17 million tons of CO_2 may not seem like a significant amount, it is over 10% of the emissions produced by this system, and illustrates the uncertainty that Weitzman observed.

The incremental abatement system cost curve becomes even more complicated when consumer response is considered. In these first two simulations, only producers responded to a change in CO_2 prices by minimizing production costs for an exognenous quantity of electricity demanded. Fabra and Reguant (2013) conclude that most emissions costs are passed through to retail electricity consumers. Since the demand for electricity is not perfectly inelastic, consumers will respond to increased electricity prices. For the next simulation, the model ran with the original fuel prices and a price elasticity of demand of -0.2. The incremental cost of abatement curve now represents the system, i.e. the interaction of supply and demand for electricity, and not just the cost minizing decisions of utilities, and is shown in Figure 6.

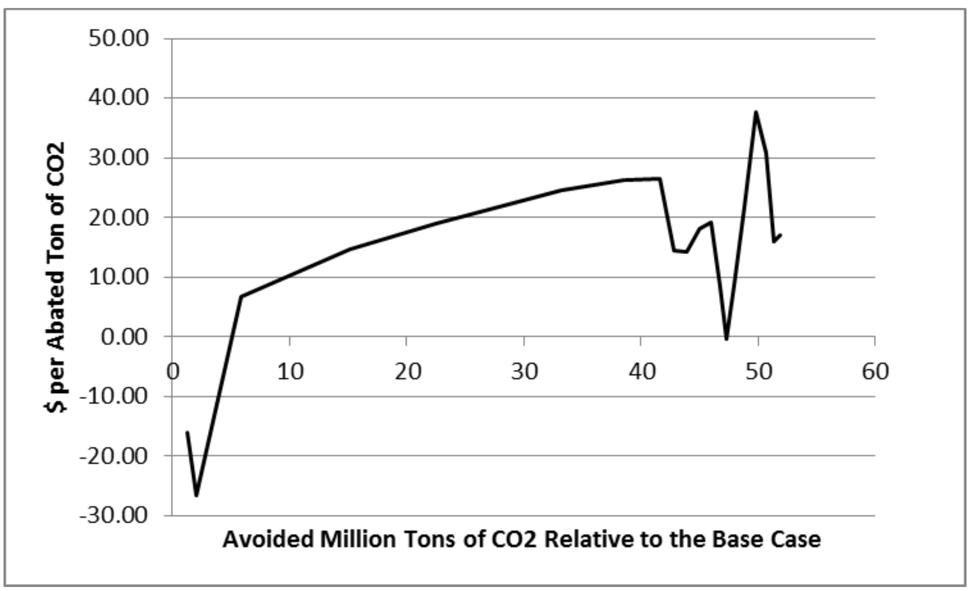

Figure 6. Incremental Abatement Cost Curve for 2015 with Demand Response

With consumers and producers both responding to CO_2 prices, there are two countervailing factors affecting this curve. Note again that this is no longer the producer's incremental cost curve, as the quantiy of electricity produced is not the same at every point. It is therefore the incremental system cost of abatement curve considering both the actions of consumers and producers in the market for electricity. At higher CO_2 prices, producers are switching to more expensive, lower emitting fuels, leading to higher costs and lower emissions. But higher CO_2 prices are leading to higher realized electricity prices and are also causing consumers to purchase less, leading to lower costs and lower emissions. As a result, the shape of the incremental system cost curve is determined by which factor dominates at a particular level of abatement. Recall that at low levels of abatement, producers are not engaging in much fuel switching, but consumers are purchasing less, so the consumer effect dominates the producer effect and incremental system costs of abatement are negative, implying that, except for the carbon price, the cost of producing electricity declines because the quantity produced declines. Once CO_2 prices become high enough, producers switch fuels, and this increases costs despite decreased consumption. This leads to an incremental system cost curve that is no longer monotonically increasing. In Figure 4 and Figure 5, the determination of the optimal level of abatement given a CO_2 tax was relatively straightforward. Given the adaptation by both consumers and producers, this determination is less so. A CO_2 tax of $20 will cross the incremental system cost of abatement curve at both 22 million tons and 49 million tons abated, and further guidance is necessary to determine the optimum.

Note that this uncertainty in the emissions level implied by the equality of marginal costs and marginal benefits in Figure 6 is economically significant. The total emissions for Florida's electricity generating sector in 2015 is modeled to be approximately 125 million tons. The 27 million ton difference between these two levels that could be considered optimal is over 20% of total emissions. The challenge, then, 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, the optimal level(s) may vary significantly as fuel prices change, and the optimal levels may be economically significant. 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.

VII. Conclusions

Most of the literature on the abatement of CO_2 emissions focuses on 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 costs to the consumer, however, it is important to ensure that those costs are commensurate 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 static least-cost economic dispatch model, this paper analyzes the effects that various emissions prices 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.

This causes two major problems in the determination of the optimal level of emissions. The question of what constitutes optimal emissions abatement policies is complicated by the fact that the marginal customer cost curves may not be ‘well-behaved’. This complicates either of the two main types of policy instruments used to control emissions levels. First, if emissions control through a carbon tax is considered, it may not result in the desired level of emissions abatement due to a flat marginal cost of abatement curve. 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. Second, the incremental customer cost curves may intersect with the marginal benefits of abatement at many levels of abatement, allowing for different characterizations of the ‘optimum’. Therefore, identification of the marginal costs and the marginal benefits of CO_2 abatement remains a necessary condition for the determination of an optimal level of abatement, but not a sufficient one.

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