Consumer Cost Effectiveness of CO_2 Mitigation Policies in Restructured Electricity Markets

Jared Moore[1,2] and Jay Apt[1,2,3]

1 Carnegie Mellon Electricity Industry Center, Carnegie Mellon University
2 Department of Engineering and Public Policy, Carnegie Mellon University
3 Tepper School of Business, Carnegie Mellon University,

Email: jaredmoo@andrew.cmu.edu

ABSTRACT

We examine the cost of carbon dioxide mitigation to consumers in restructured markets under two policy instruments, a carbon price and renewable portfolio standards (RPS). To estimate the effect of policies on market clearing prices, we constructed an hourly economic dispatch model of the generators in PJM, ERCOT, and MISO. We find that the cost effectiveness of policies for consumers is strongly dependent on the price of natural gas and on the characteristics of the generators in the dispatch stack. If gas prices are low (~$4/MMBTU), a technology-agnostic, rational consumer seeking to minimize costs would prefer a carbon price over an RPS in every region. Expensive gas (~$7/MMBTU) requires a high carbon price to induce fuel switching and this leads to wealth transfers from consumers to low carbon producers. The RPS may be more cost effective for consumers because the added energy supply lowers market clearing prices and reduces CO_2 emissions. We find that both policies have consequences in capacity markets and that the RPS can be more cost effective only if existing capacity supply remains adequate.

Keywords: cost effectiveness, carbon price, renewable portfolio standards, restructured markets, capacity markets, natural gas, wind energy

1. INTRODUCTION

The U.S. Environmental Protection Agency (EPA) has begun a rulemaking process to regulate greenhouse gas emissions from existing power plants through Section 111(d) of the Clean Air Act [1]. This section requires states to meet federal standards through EPA approved State Implementation Plans (SIPS). SIPS may include "market-based instruments, performance standards, and other regulatory flexibilities" [1]. One of the significant state-to-state differences is the presence or absence of organized electric power markets. Here we examine the cost effectiveness of CO_2 mitigation policies in three restructured markets.

There appears to be a consensus that a price on carbon is the favored policy mechanism among economists for its efficiency [2] [3] [4] [5] [6]. As an example, Metcalf writes, "For economists, the obvious choice is to move toward market-based environmental mechanisms that put a price on greenhouse gas emissions" [6].

However, economists and policy-makers have different perspectives on quantifying costs. Economists view wealth transfers as welfare neutral. On the other hand, such transfer payments are important to elected and appointed officials; they are sensitive to costs from the perspective of their constituents — consumers. Federal and state administrations have explicitly cited increased prices for consumers as undesirable, using language such as "...ensure that the standards are developed … with the continued provision of reliable and affordable electric power for consumers and businesses" [1]. Lisa Jackson, EPA Administrator from 2009-2013, echoed this perspective by stating that a key principle of the regulations will be to "…implement the most cost-effective measures that do not burden small businesses and nonprofit organizations" [7]. State policy-makers generally view costs from the consumer perspective. A meta-study by Lawrence Berkeley National Laboratory (LBNL) on state renewable portfolio standards (RPS) showed that every state that quantified carbon abatement costs did so from the consumer's perspective (i.e. difference in the costs to rate-payers) [8].

The perspective economists take concerning neutrality of wealth transfer payments is particularly important in restructured markets. Electricity is a commodity in restructured markets, where consumer costs are driven by market clearing prices. Carbon policies may either raise or lower market clearing prices [9] and the differences have large transfer payment implications. Existing low carbon generators could receive a windfall profit from a carbon price. Carbon intense generators may lose profits (but create tax revenue).

In order to estimate consumer cost and tax revenue effects of carbon mitigation policies in restructured markets, we examine two policies to reduce CO_2 emissions: a carbon price and renewable energy standards. For each policy, we observe how sensitive cost effectiveness is to the price of natural gas by varying the price from $4 to $7/MMBTU. We compare the differences in cost effectiveness if reductions in consumer surplus are considered a cost or neutral. We also examine the effects to PJM's capacity market from the change in profits of generators. In addition to estimating the costs in PJM, we examine MISO and ERCOT to see if our results are sensitive to a different mix of generators.

We find that from an economist's perspective, where wealth transfers are neutral, a carbon price is indeed the most cost effective mechanism. For consumers, however, an RPS may be more cost effective than a carbon price when natural gas is expensive ($7/MMBTU or more). Expensive gas requires a high carbon price to induce fuel switching and this leads to wealth transfers from consumers to low carbon producers. The RPS may be more cost effective for consumers because the added energy supply lowers market clearing prices and reduces carbon emissions. We find that both policies have consequences in capacity markets because they affect profits of fossil generators. Renewables supply energy but supply very little capacity [10], and the RPS is more cost effective than a price on carbon for consumers only if existing capacity supply remains adequate.

2. METHODS

We use as a metric for cost effectiveness the cost per unit of reduced greenhouse gas emissions, dollars per tonne of CO_2 (\$/tCO_2) [11]. For consumers in restructured markets, electricity is a commodity and the costs of policies are quantified by market clearing prices net of any related change in tax revenue. Tax revenue is increased by a carbon price and decreased by renewable energy subsidies. It has been shown that the changes in tax revenue would not equitably affect consumers even if the tax revenue was redistributed to households because lower income households spend a larger share of their income on energy [6]. Here, we do not consider the issue of equitable tax distribution and assume the changes in tax revenue affect consumers equally. In this approximation, cost effectiveness of carbon mitigation policies can be estimated for consumers as:

$$Cost\ Effectiveness\ (Consumer) = \frac{\Delta Electricity\ Market\ Prices + \Delta Tax\ Revenue}{\Delta CO_2\ Emissions}$$

To examine the difference in market clearing prices of energy markets under a carbon price and under an RPS, we created an hourly economic dispatch model of the generators in PJM, MISO, and ERCOT. Power plant fuel costs, heat rates, variable O&M costs, and carbon intensities for each region were obtained from Ventyx Velocity Suite [12].

Hourly load for 2012 was obtained from ERCOT and PJM [13] [14]. Hourly load data was unavailable for MISO, so the MISO hourly load was estimated by scaling down PJM data based on 2012 peak load differences [15] [16]. PJM was the only one of the three regions for which 2012 hourly wind generation data were available [17]. For MISO and ERCOT, hourly wind production was scaled from National Renewable Energy Lab's eastern wind dataset [18] to meet annual generation levels reported for each region for 2012 [19] [20].

The dispatch model calculates marginal costs for all generators then dispatches the least expensive generators necessary to meet load on an hourly basis. All variable costs, including a price on carbon, were assumed to be passed on as marginal costs in the bids of generators. The market clearing price is set by the marginal generator, and all generators receive the market clearing price for that hour. Transmission, ramping, and security constraints are not included in the dispatch model. We assumed that fuel costs remained constant except for natural gas which we varied from $4-$7/MMBTU.

2.1 Time Frame and Power Plant Turnover Assumptions

Policy cost estimates inherently require uncertain assumptions over some arbitrarily chosen time horizon. We make the following simplifying assumptions.

We limit the analysis to the short term by assuming demand and the mix of generators in each region stays the same as it was in 2012. We assume demand remains constant, as it has been from 2005 through 2012 [21]. EIA has projected existing capacity to remain adequate until 2023 [22], so we model a mix of generators identical to that in 2012. We acknkowledge that older, less efficient power plants may be forced to retire due to pending environemntal regulations in the interim. However, their high heat rates preclude them from being major players in energy markets; thus their exclusion would not substantially alter our findings. In the supporting data, we examine an alternate scenario in which 18 GW [23] of small, old coal plants are retired in PJM.

With excess capacity and flat demand, construction of new capacity is expected to be low [22]. Inexpensive shale gas further disincentivizes new power plants because of lower market clearing prices in energy markets. New power plants are not profitable at low carbon prices according to our dispatch model. Over time when new capacity is needed, the decision will be based on the conditions of energy markets and capacity markets along with environmentally related incentives. After discussing our results for policies in energy markets, we examine whether the effect on capacity markets induces the construction of new power plants or the retirement of old power plants.

On the consumer side, we make the assumption that demand is inelastic to price changes. Reductions in consumption are unlikely to be incorporated in the new EPA regulations, since §111(d) of the CAA regulates existing power plants and not consumers. The value of elasticity in the electricity industry is relatively small and uncertain [24] [25] [26]. There is also concern over how much of the reduction would occur because of inter-state leakage [27].

2.2 Carbon Dioxide Mitigation Quantity

A price on CO_2 disadvantages coal fueled generators and causes other generators to be dispatched first; this is termed fuel switching. Our model estimates for each RTO the amount of carbon reduced due to a given carbon price (Figure 1) over a baselines set by the CO_2 emissions output of our dispatch model at a given natural gas price and 2012 modeling data. Figure 1 shows that the effectiveness of the carbon price is dependent on the price of natural gas and the amount of gas capacity in each region. For each region, the line stops when market conditions induce either new NGCC plants or new wind plants.

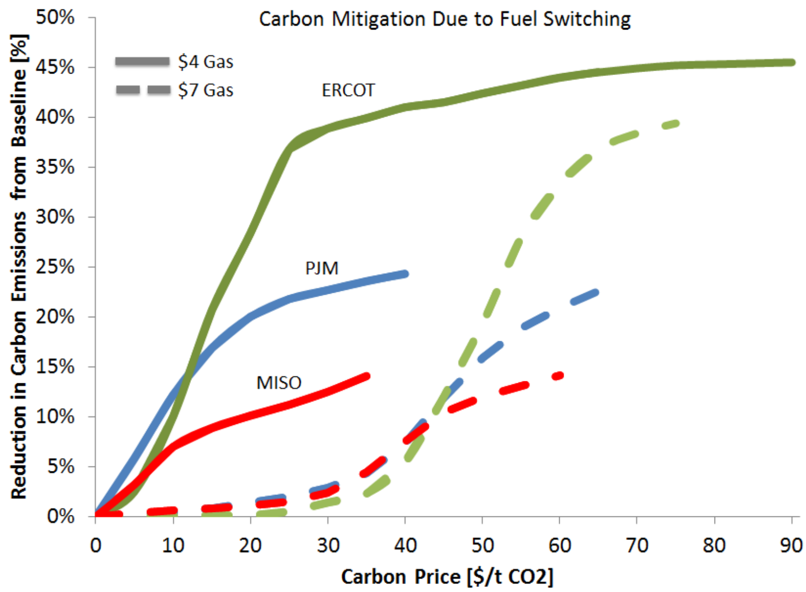

Figure 1*: Carbon mitigation due to fuel switching as a result of a carbon price. Solid lines are for natural gas at $4/MMBTU; dashed lines are $7 gas. The lines stop when new capacity is profitable as a result of a carbon price and natural gas price. In the $4 gas case, new NGCC plants are induced. In the $7gas case, new wind plants are induced. We assume that the levelized cost of wind is $85/MWh and the levelized cost of a new NGCC plant is $135/MW-year* [28]. *NGCC plants may be profitable at slightly lower carbon prices than indicated in the figure because of revenue from capacity markets.*

2.3 Transfer Payment Implications of a Carbon Price

Should gas prices reach $7/MMBTU, a higher carbon price would be necessary to induce new power plants or fuel switching. These price changes lead to transfer payments (Figure 2). In PJM, the carbon price raises the market clearing price and leads to increased profits for low carbon generators. In ERCOT, a carbon price may cause transfers from producer surplus to tax revenue. ERCOT does not have as many existing low carbon generators to take advantage of the carbon price. If coal is dispatched despite the carbon price, its producer surplus is transferred to tax revenue. The price of electricity is (to first order) unaffected, since gas sets the market clearing price. The changes in profits affect capacity markets and may cause some generators to extend or cease operations; we discuss this further below.

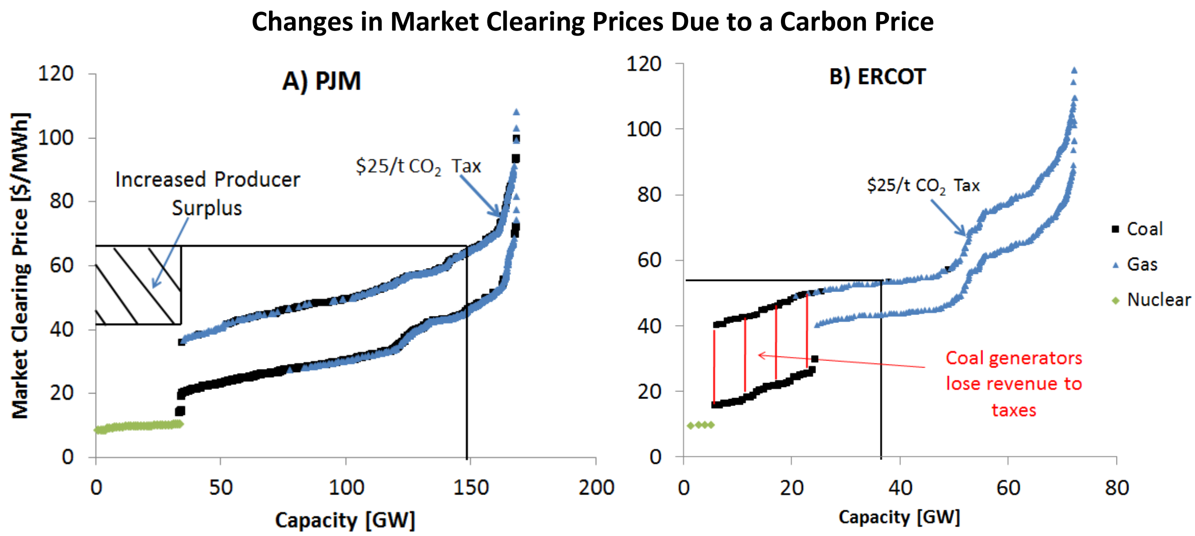

Figure 2: *The effect of a $25/tonne CO_2 price in (a) PJM and (b) ERCOT. In PJM, low-carbon generators benefit from a price on carbon but do not change their order in the dispatch stack. In ERCOT, carbon intense generators that remain in the dispatch stack lose profit to tax revenue.*

2.4 Renewable Portfolio Costs and Transfer Payment Implications

A price on carbon raises market clearing prices; renewables lower it. Renewable generators increase energy supply with very low short-run marginal cost, push the energy supply curve to the right, and lower market clearing prices (SD Figure S2) [29] [30]. The lowered market clearing prices decrease the profits of fossil generators [29]. Here, we make the assumption that these savings are passed on to consumers in the form of lower wholesale power prices.

We assume that whatever technology is used to meet the RPS has the same hourly production pattern as wind energy did in 2012. We assumed the cost of the renewable energy to consumers is equal to its levelized cost of electricity (LCOE). Renewable energy is induced through a combination of revenue from bilateral power purchase agreements, renewable energy credits, and other subsidies. The sum of the revenue received by renewable energy developers would be approximately equal to the LCOE.

The DOE estimates that 500 GW of wind are available at ~$85/MWh or less, not including integration costs or subsidies [31]. We find that the most recently-available assumptions available would also yield a levelized cost [32] of about $85/MWh: a capital cost of $1940/kW [33], a fixed charge factor of 12%, a capacity factor of 35% [33], and O&M costs of $25/kW-year [33].

Wind also has costs due to variability and transmission not typically included in LCOE estimates [34]. Utilities would pass these costs onto consumers, so we include them here. The 2012 DOE Wind Technology Market Report estimates variability costs to be in the range $2.5-$10/MWh [33]. For transmission costs unique to wind, LBNL performed a meta-study that found the cost of transmission to be $10-$15/MWh [35]. We add these costs, which utilities would pass onto consumers, to estimate a total levelized cost of approximately ~$100/MWh of wind.

We examine wider bounds than the costs described above because of the wide range of costs found in literature [34] [36] and the unpredictability of technology and subsidies. The federal government (sometimes) provides a production tax credit of $23/MWh [37]. In our results, we examine cost effectiveness if the added energy cost $80, $100, or $120/MWh from the perspective of consumers.

3. RESULTS

3.1 PJM Energy Market

In Figure 3, we show the marginal cost effectiveness of policies in PJM's energy market. From an economist's point of view, where wealth transfers are neutral, our results indicate that a carbon price is (as expected) the most cost-effective option. As theory would suggest, the marginal cost of abatement is equivalent to the carbon price. If wealth transfers are neutral, the RPS would cost approximately ~$40-$80/t CO_2 more than a carbon price.

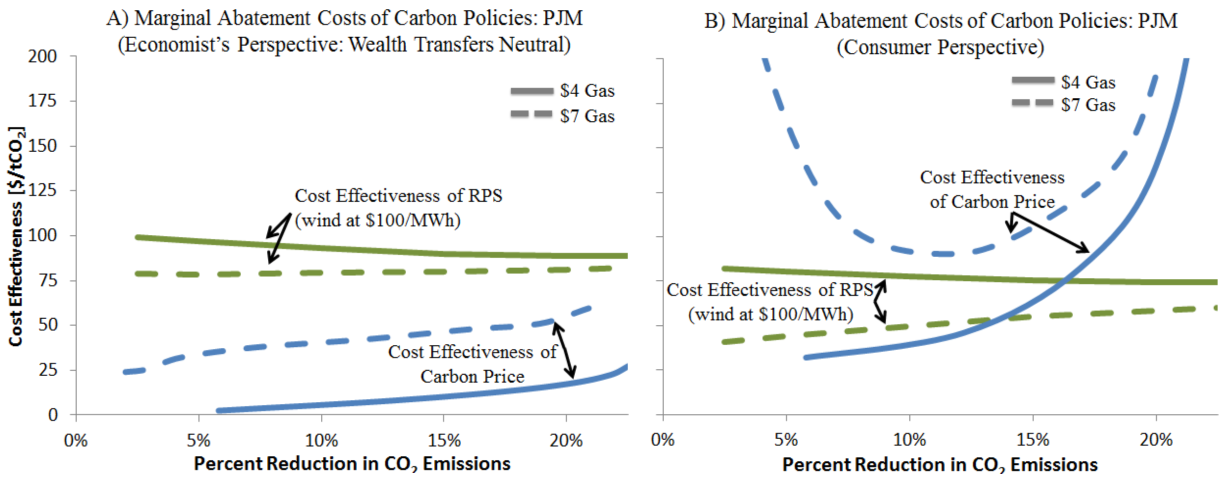

Figure 3: *Cost effectiveness of carbon mitigation policy options in PJM using 2012 data as the baseline. Figure 3(a) shows the marginal abatement costs of policies if transfer payments are neutral. The marginal cost of abatement is equal to the carbon price. Figure 3(b) shows the marginal abatement costs of policies from the consumer perspective. If wind costs are $80/MWh, costs are approximately $20/tCO$_2$ less expensive than in the figure. If wind costs are $120/MWh, costs are approximately $30/tCO$_2$ more expensive than in the figure. In the supporting data, we show the average cost effectiveness if a 20% reduction is required (SD Figure S4).*

From the consumer perspective, the most cost effective policy is dependent on market conditions. A carbon price is the most cost effective option for consumers at low natural gas prices and low carbon prices (less than ~$15/t CO_2). With high gas prices, consumers may pay less per tonne offset with an RPS. A carbon price is not cost effective with high gas prices because the high carbon price necessary (Figure 1) leads to a wealth transfer at the expense of consumers. The cost effectiveness of the RPS is improved by higher natural gas prices because the supply of renewable energy does more to suppress market clearing prices. In the next section we consider capacity markets.

3.2 PJM Capacity Market Implications

Power plant bids in capacity markets are driven by fixed costs (PJM refers to these as "avoidable costs" [38]) less profits made in energy markets [39]. Carbon dioxide mitigation policies affect capacity markets because they affect the profits of generators in energy markets. If generators increase their bids in capacity markets as a result of carbon policies, the cost to consumers can be appreciable [8].

Capacity markets are volatile [39] [40] [41]. For the PJM Base Residual Auctions from 2007 to 2017, the RTO resource clearing price has varied between $16-$174/MW-day [42]. This is a consequence of uncertain demand [41] and the steep supply curve of capacity market bids in PJM; it increases by over $300/MW-day for the last 10 GW offered [42].

Given the volatility of capacity markets, models of the market do not exhibit a high degree of accuracy. However, it is feasible to examine how policies affect the bids of plants that may be on the margin in capacity markets—existing coal generators or new NGCC power plants. Coal plants appear to be on the margins in the PJM capacity market, as 10 GW of coal plants did not clear in the 2016/2017 capacity market auction [42].

In Figure 4, we show how capacity market bids of coal and NGCC power plants change as a result of carbon policies. Without revenue from energy markets, the avoidable costs of an existing coal fired power plant and a new NGCC plant are approximately $160/MW-day and $370/MW-day, respectively [28] [38]. Lower bids are submitted to capacity markets as generators earn revenue in energy markets. We estimate that revenues from energy markets would allow the power plants to make bids of $105/MW-day and $350/MW-day, respectively[1]. We use The Brattle Group's estimates for the cost of new entry (CONE) in PJM for NGCC plants [28]. Coal plant performance is based on data from the 2012 PJM State of the Market Report [38] and marginal costs of existing power plants in our dispatch model [12]. The bids of generators change as profits are affected by carbon policies (Figure 4).

[1] These estimates assume that a coal plant has a marginal cost of $25/MWh per data from Ventyx Velocity Suite [12]. We assume that the NGCC plant has a marginal cost of $29/MWh per NGCC performance data from Brattle's CONE analysis [28] and a gas price of $4/MMBTU. The coal plant earns higher profits in energy markets and can make lower capacity market bids as a result.

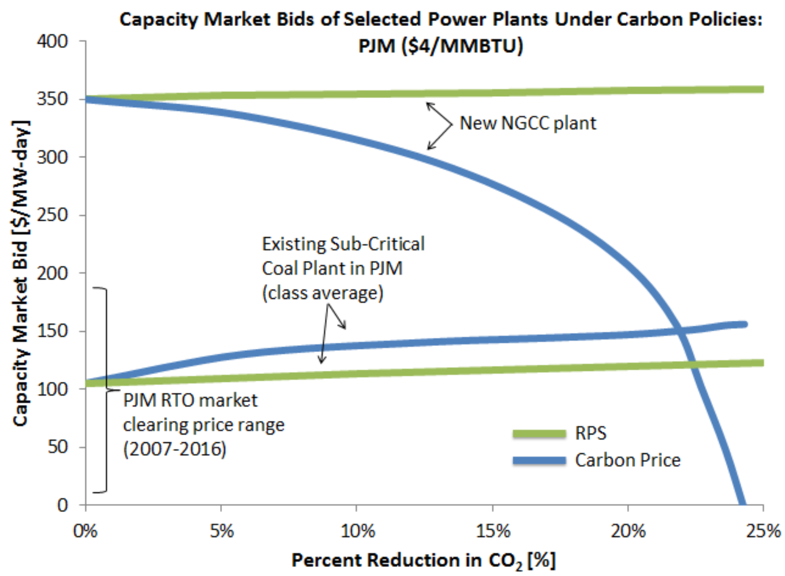

***Figure 4:** Modeled capacity market bids in PJM of new NGCC plants and existing coal plants under a carbon price and an RPS assuming a gas price of $4/MMBTU.*

A CO_2 price has a larger effect on capacity bids than does an RPS because gas and coal plants switch their positions in the dispatch stack. The RPS does not change the order of the dispatch stack; it simply displaces the marginal generator. For a 20% reduction in CO_2, the RPS raises the bid of an existing coal power plant by $15/MW-day whereas a carbon price raises it by $40/MW-day.

As long as existing generators satisfy capacity supply, the capacity market reaction from policies appears moderate and unlikely to change the decision of a policy-maker. Over a year, a $15/MW-day or $40/MW-day increase in PJM capacity prices would result in additional costs to consumers of $0.9B to $2.3B, respectively (with 165 GW of capacity in PJM [42]). We summarize as follows for a 20% reduction in CO_2 emissions. For the carbon price, the cost of mitigation increases from ~$65 to $90/t$CO_2$. For an RPS, the mitigation cost increases from ~$75 to $90/t$CO_2$.

When new capacity is needed, however, a carbon price could lead to significantly lower capacity prices than an RPS. A carbon price lowers the bids of new NGCC plants by increasing profits in energy markets. An RPS does the opposite by undercutting profits of all fossil plants in energy markets.

Policy-makers may favor a carbon price simply to increase capacity supply and decrease dependence on volatile capacity markets. A carbon price makes new gas plants and existing nuclear plants more competitive by increasing profits in energy markets. Exelon is considering closing nuclear power plants in PJM due to low revenues in energy markets and the volatility of capacity markets [43]. An RPS would increase dependence on capacity markets by further undercutting fossil profits in energy markets [44]. In order for the RPS to be cost effective for consumers, markets must retain nuclear generators, attract new capacity, and do so without drastic increases to capacity market prices.

3.3 ERCOT

As shown in Figure 2 above, the wealth transfer implications of a carbon price in ERCOT are different from PJM. ERCOT has few nuclear generators, large gas capacity, inexpensive coal, and no capacity market. The dominant wealth transfer effect of a carbon price is coal generators losing profits to tax revenue. Figure 5 below shows the two perspectives of carbon policies in ERCOT.

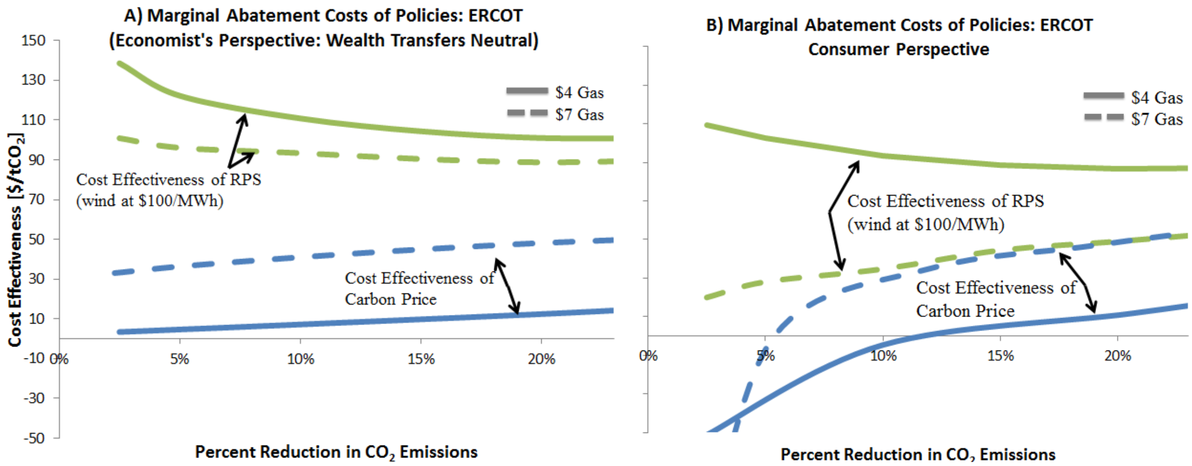

Figure 5: *Cost effectiveness of carbon mitigation policy options in ERCOT. Figure 5(a) assumes transfer payments are welfare neutral. Figure 5(b) assumes the consumer perspective. From the consumer perspective, so much producer surplus is transferred to tax revenue by the carbon price that consumers surplus may increase. This causes the negative cost effectiveness estimates. Figures showing alternate costs of wind are in the supporting data. If wind costs are $80/MWh, costs are approximately $30/tCO$_2$ less expensive than in the figure. If wind costs are $120/MWh, costs are approximately $40/tCO$_2$ more expensive than in the figure above. In the supporting data, we show the average cost effectiveness if a 20% reduction is required (SD Figure S5).*

Figure 5 shows that a carbon price in ERCOT is more cost effective from the consumer point of view than an RPS under the assumption that tax revenues from the CO_2 price accrue to consumers. In the expensive gas case, the RPS can be cost effective for consumers because it lowers the market clearing price in gas-heavy ERCOT.

ERCOT does not have a capacity market, so we cannot model whether coal generators would cease operations as a result of lost profits. The RTO expects capacity to become extremely tight with low gas prices and no capacity market [45]. The short capacity situation in ERCOT is expected to lead to larger price spikes, which in theory effectively act as capacity payments [46].

We summarize our results for PJM and ERCOT for a 20% reduction in carbon dioxide emissions from the baseline year of 2012 in Table 1.

Table 1: Cumulative Cost of Abatement for 20% Reduction of CO_2 [$/t$CO_2$]

			CO_2 Price		RPS		CO_2 Price	RPS	CO_2 Price	RPS
CO_2 Reduced	Region	Perspective					With existing coal setting prices in the capacity market		With new NGCC setting prices in the capacity market	
			$4 Gas	$7 Gas	$4 Gas	$7 Gas	$4 Gas		$4 Gas	
20%		Economist	10	40	90	80				
20%	PJM	Consumer	65	190	75	60	95	85	-50	80
20%		Economist	10	40	110	90				
20%	ERCOT	Consumer	0	-20	95	40				

3.4 MISO

Of the three regions examined, MISO has the least fuel diversity and largest excess capacity supply [22]. The dominance of coal means that market clearing prices rise quickly with carbon prices. MISO is the only region for which the model shows that new capacity is profitable with a carbon price without reaching a 20% reduction in carbon emissions. Because of the lack of fuel diversity, the wealth transfer effects are smaller than in the other regions (SD Figure S3). Like other regions, an RPS is more cost effective for consumers when gas is expensive. However, because of the small differences in cost effectiveness, policy decisions are more likely to be driven by other factors such as fuel diversity. Given the lack of natural gas in MISO, strength of the wind resources [33], and excess capacity [20], policy makers may find an RPS the most feasible option.

We do not include MISO in Table 1 because new NGCC plants will be profitable with a price on CO_2 well before a 20% reduction in emissions is reached. Adding new combined-cycle gas plants until a 20% reduction is reached would not lead to consistent comparisons with PJM and ERCOT. A comparison of all three regions at 10% reduction is given in Table S1 in the supporting data.

4. DISCUSSION

We examined the cost effectiveness of a carbon price and of an RPS in restructured markets. From an economist's perspective, where wealth transfers are neutral, we find that a carbon price is (as expected) the most cost effective mechanism. This research adds a perspective that is relevant to policy-makers: in the short term, how will these policies affect consumers?

We find that the cost effectiveness of policies for consumers is strongly dependent on the price of natural gas and the characteristics of the generators in the dispatch stack. If gas prices are low (~$4/MMBTU), a technology-agnostic, rational consumer seeking to minimize costs would prefer a carbon price over an RPS in every region. A relatively low carbon price is required to induce fuel switching when gas is inexpensive. The low carbon price minimizes wealth transfers and the marginal cost of mitigation to consumers is $\lesssim$ \$50/t CO_2.

If gas prices are high ($7/MMBTU), for a 20% reduction of CO_2 in PJM, a consumer would find that a carbon price mitigates CO_2 for an average of \$190/tCO_2, much higher than the average RPS mitigation cost of \$60/tCO_2 (SD Figure S4). However, in ERCOT, the consumer would find that a carbon price is considerably less expensive than an RPS as a mitigation strategy because of the creation of tax revenue (SD Figure S5). With expensive gas in MISO, the average cost of abatement for a 10% reduction is nearly identical for the two strategies (SD Figure S3).

As long as existing generators satisfy capacity supply, the effect of policies on capacity markets is limited and would not affect a policy maker's decision. However, if new capacity is needed, a carbon price substantially reduces the capacity market bids of new NGCC plants. Policy-makers concerned with the low capacity supplied by an RPS could include other low carbon technologies that may have a higher LCOE [36], such as coal with carbon capture and sequestration or nuclear.

Our results indicate that SIPS may be a more pragmatic mechanism for regulating emissions from power plants than a single national policy because they allow states to consider the most cost-effective mechanism for their situation and stakeholder priorities. This result agrees with that from different lines of research [9] [29].

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Consumer Cost Effectiveness of CO_2 Mitigation Policies in Restructured Electricity Markets

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Supporting Data

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SUPPORTING DATA

Analysis of 18 GW of Coal Missing in PJM

In the analysis above, we assumed that demand and the mix of generators in each region would stay the same as it was in 2012. Pending environmental legislation may force coal generators to retro-fit, and PJM estimates that 11 GW of coal are at "high risk" of retirement and another 14 GW are "at some risk" [23]. PJM estimates that the best physical screening for plants at risk of retirement are those over 40 years old and with capacity less than 400 MW [23]. We applied this screening tool to our mix of generators and removed 18 GW of old, small coal plants from the dispatch stack. Below in Figure S1, we show results with these coal plants removed.

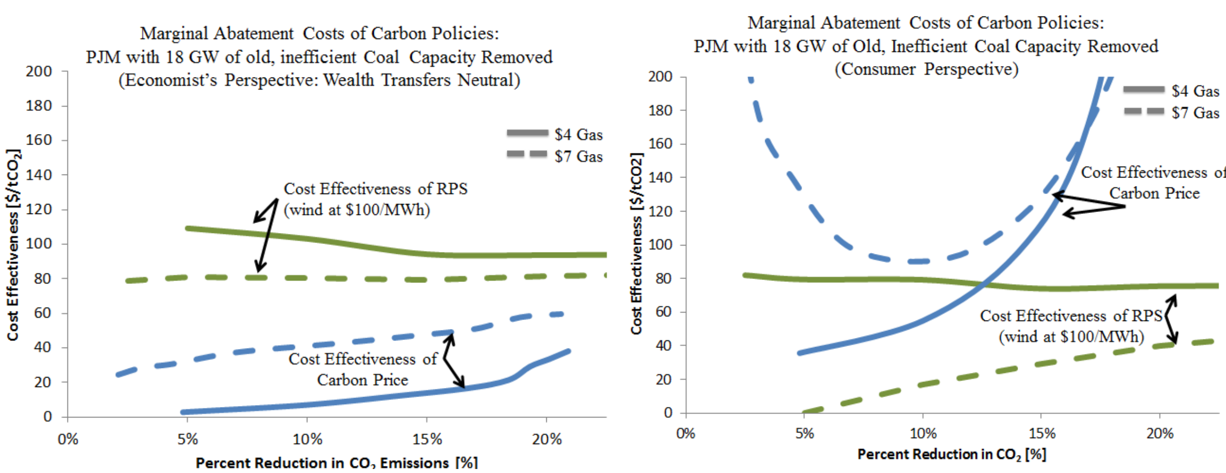

Figure S1: *Cost effectiveness of carbon mitigation policy options in PJM using 2012 data with 18GW of coal removed as the baseline. The graph on the left shows the marginal abatement costs of policies if transfer payments are neutral. The marginal cost of abatement is equal to the carbon price. The figure on the right shows the marginal abatement costs of policies from the consumer perspective.*

Figure S1 above shows similar results to Figure 3 of the main text. This shows that the coal generators expected to be lost have high heat rates and are not be major contributors to our results in energy markets.

Effect of Wind on Market Clearing Prices in PJM

In Figure 2 in the main text above, we show how a carbon price increases market clearing prices. Below in Figure S2, we show how renewables lower market clearing prices.

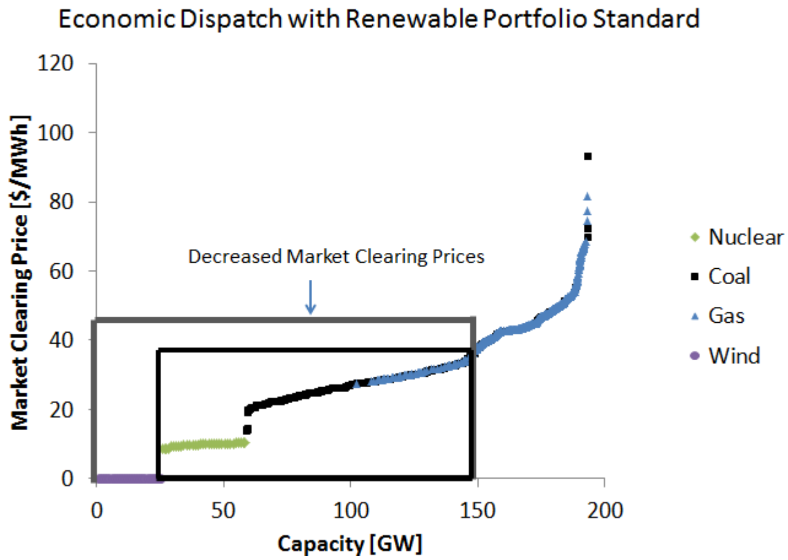

Figure S2: *25 GW of wind are generated during a particular hour. Moving the dispatch stack to the right lowers the market clearing price from approximately $45/MWh to $38/MWh.*

Average Cost Effectiveness in MISO

Below in Figure S3, we show the cost effectiveness of a 10% reduction in carbon emissions in MISO. Figure S3 shows that consumers would pay approximately ~$50/t$CO_2$ if either a carbon price or an RPS was used in the $7/MMBTU gas scenario. If gas was $4/MMBTU, a carbon price would be the more cost effective option for consumers.

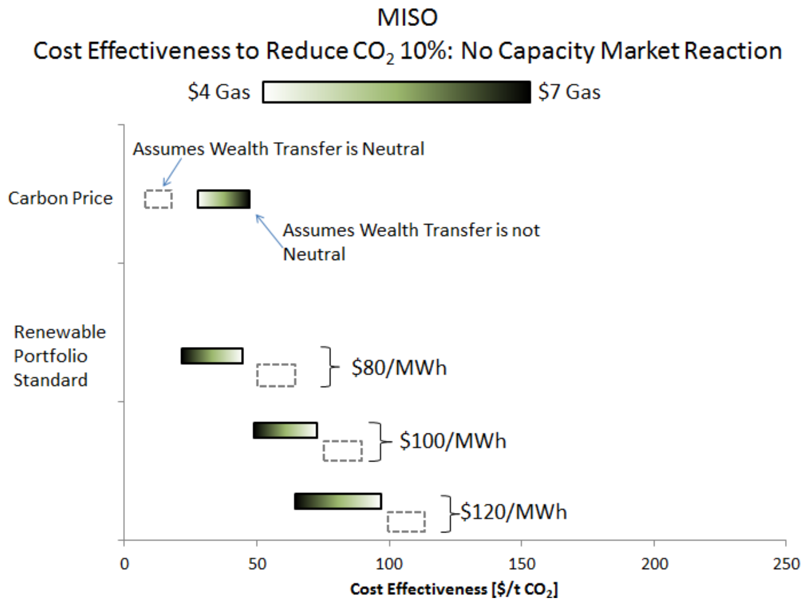

Figure S3: *Cost effectiveness of mitigating carbon 10% in MISO. We varied the cost of wind between $80-$120/MWh and the cost of gas from $4-$7/MMBTU. Colored boxed indicate the consumer point of view and gray boxes indicate an economist's point of view where wealth transfers are neutral.*

Average Cost Effectiveness in PJM

Below in Figure S4, we show the average cost effectiveness of a 20% reduction in carbon emissions in PJM.

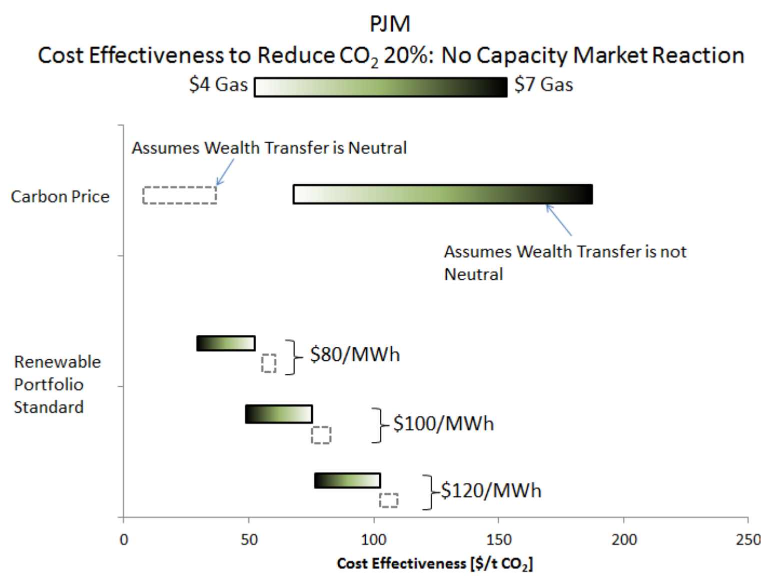

Figure S4: *Cost effectiveness of mitigating carbon 20% in PJM. We varied the cost of wind between $80-$120/MWh and the cost of gas from $4-$7/MMBTU. Colored boxed indicate the consumer point of view and gray boxes indicate an economist's point of view where wealth transfers are neutral.*

Average Cost Effectiveness in ERCOT

Below in Figure S5, we show the average cost effectiveness of a 20% reduction in carbon emissions in ERCOT.

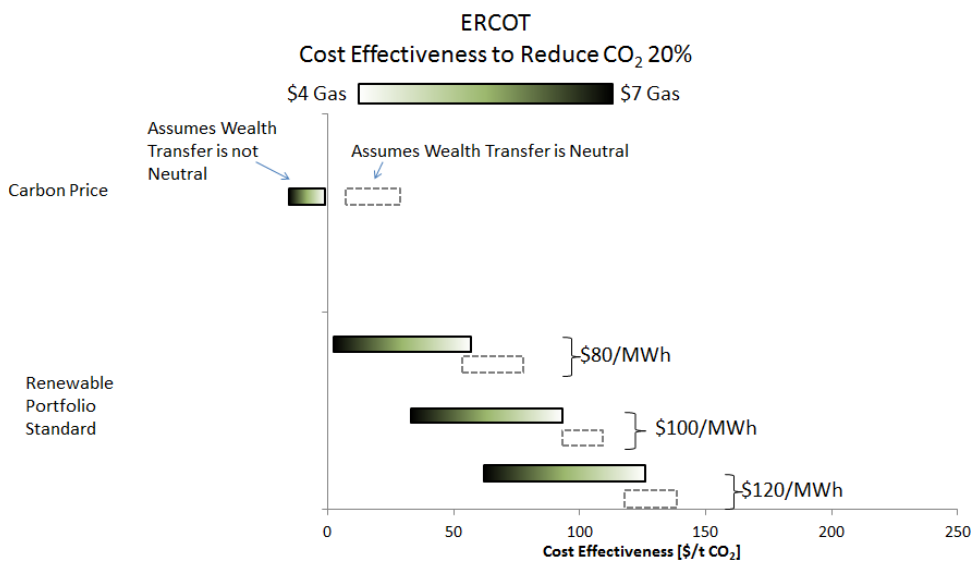

Figure S5: *Cost effectiveness of mitigating carbon 20% in ERCOT. We varied the cost of wind between $80-$120/MWh and the cost of gas from $4-$7/MMBTU. Colored boxed indicate the consumer point of view and gray boxes indicate an economist's point of view where wealth transfers are neutral.*

Cumulative Results for 10% Reduction in CO_2 Emissions

We summarize our results for PJM, ERCOT, and MISO for a 10% reduction in carbon dioxide emissions from the baseline year of 2012 in Table S1.

Table S1: Cumulative Cost of Carbon Abatement for 20% Reduction of CO_2 in PJM and ERCOT [\$/tCO_2]

			Carbon Price		RPS		Carbon Price	RPS	Carbon Price	RPS
CO_2 Reduced	Region	Perspective					With existing coal setting prices in the capacity market		With new NGCC setting prices in the capacity market	
			$4 Gas	$7 Gas	$4 Gas	$7 Gas	$4 Gas		$4 Gas	
10%	PJM	Economist	5	30	90	80				
10%		Consumer	40	220	80	50	65	85	-20	90
10%	ERCOT	Economist	5	40	120	100				
10%		Consumer	-20	-60	100	30				
10%	MISO	Economist	10	30	90	75				
10%		Consumer	30	50	70	50				