Short run effects of a price on carbon dioxide emissions from U.S. electric generators

Adam Newcomer, Seth A. Blumsack,
Jay Apt, Lester B. Lave, and M. Granger Morgan

Abstract

The price of delivered electricity will rise if generators have to pay for carbon dioxide emissions through an implicit or explicit mechanism. There are two main effects that a substantial price on CO_2 emissions would have in the short run (before the generation fleet changes significantly). First, consumers would react to increased price by buying less, described by their price elasticity of demand. Second, a price on CO_2 emissions would change the order in which existing generators are economically dispatched, depending on their carbon dioxide emissions and marginal fuel prices. Both the price increase and dispatch changes depend on the mix of generation technologies and fuels in the region available for dispatch, although the consumer response to higher prices is the dominant effect. We estimate that the instantaneous imposition of a price of \$35 per metric ton on CO_2 emissions would lead to a 10% reduction in CO_2 emissions in PJM and MISO at a price elasticity of -0.1. Reductions in ERCOT would be about one-third as large. Thus, a price on CO_2 emissions that has been shown in earlier work to stimulate investment in new generation technology also provides significant CO_2 reductions before new technology is deployed at large scale.

Introduction

Recent judicial [1, 2], political [3-5] and industrial [6-11] actions suggest that there may soon be either an explicit or implicit price on carbon dioxide (CO_2) emissions in the United States. Because 72% of the electricity generated in the U.S. comes from carbon intensive fossil fuels (50% from coal) [12] a price on carbon emissions will increase the cost of generating electricity. Previous studies [13-20] have examined the effects of the price of emitted CO_2 on firm-level decisions about what type of generation to build, and on whether to retrofit or replace an existing plant. These studies have generally found that costs of between \$35 and \$50 per metric ton (tonne) of CO_2 will be required to induce private firms to invest in low carbon technologies such as coal with carbon capture and sequestration.

Here we consider the short run effects of imposing such prices on the CO_2 emissions of the existing fleet of generation plants. That is, we consider the effects on electricity price and demand before any new or replacement capacity can be built. The replacement time for U.S. generation plants has been very long (the median size-weighted age of the in-service coal generation units is 35 years; 75% of the capacity is at least 27 years old and 25% is at least 42 years old [21]). While replacement rates would likely increase with carbon controls, clearly short run marginal carbon emission reductions are an important policy metric.

With a carbon price, electric generation units powered by fossil fuels will have increased marginal costs. In the short run (before changes in the mix of available generation could be brought online), demand for electricity could be met at the lowest cost by redispatching existing generation assets according to their marginal costs, including the costs of their carbon emissions, taking into account transmission constraints. The resulting change in electricity price due to a price on carbon depends on the portfolio of generation facilities available for dispatch and on the demand for electricity. Regions with significant amounts of low carbon generation, such as nuclear, hydroelectricity, or natural gas, would see smaller increases in generation costs, while areas that are predominantly supplied by coal generation facilities would see larger increases in short run electricity prices.

We examine the effects of a carbon price on electricity demand in three U.S. Independent System Operator (ISO) or Regional Transmission Organization (RTO) regions. We simulate the imposition of a carbon price in the Midwest ISO, ERCOT (Texas) and PJM, and calculate the resulting change in carbon dioxide emissions in each area. The online supporting information includes a discussion of the generation portfolio for each ISO included in the analysis. We quantify the effect of a carbon price on load by first redispatching existing generators in these control areas under a range of carbon prices to determine the electricity price increase due to a carbon price, and then by analyzing a range of consumers' price elasticity of demand in response to the increase in electricity price.

A price for carbon emissions can change the demand for each fuel, since it can affect the order of dispatch of the generators. We find that a carbon dioxide price of $50 per tonne or less has a small effect on the dispatch order between coal and natural gas generators (heat rate, rather than fuel, has the largest dispatch order effect). Some low-carbon plants (for example, biomass) are dispatched before fossil plants at high carbon prices, but they do not account for much capacity. The main short run effect of the price increase is to lower the demand for electricity. In the long run, consumers may respond to higher electricity prices by adjusting their stock of goods that are powered by electricity (for example, they may purchase more energy-efficient appliances); in the short run they can only curtail use. Spees and Lave [22] report a "typical" short-run price elasticity of demand approximately equal to -0.1, while the long-run elasticity is thought to be around -1. We emphasize that our analysis is confined to the short run, where the capital stock held by consumers is assumed not to change as a result of electricity price increases, and refer the reader to the extensive literature on long-run capital investment [e.g. 13-18, 22-26]. Our analysis is a partial equilibrium analysis in that we hold the prices for various generation fuels constant, however we examine the effects of fuel prices on our results.

Method

Because marginal costs for generators are not public information, we use estimates of marginal costs [27-29] as well as heat rates and fuel types from the U.S. EPA eGRID database [21] and regionally appropriate assumptions for fuel prices [30] to calculate the short run marginal cost for each existing generator in each region (Table S2 in the online supporting information contains details on the costs used for each ISO).

Demand for electric energy in each control area is met by economic dispatch within transmission constraints, with the lowest cost generation used to meet the demand. Our analysis focuses only on the demand for electric energy; we do not consider the variety of ancillary services (e.g. reactive power, voltage/frequency regulation) that generators provide. Figure 1 is an estimate of the short run marginal cost curve used for economic dispatch for the Midwest ISO in the absence of transmission constraints.

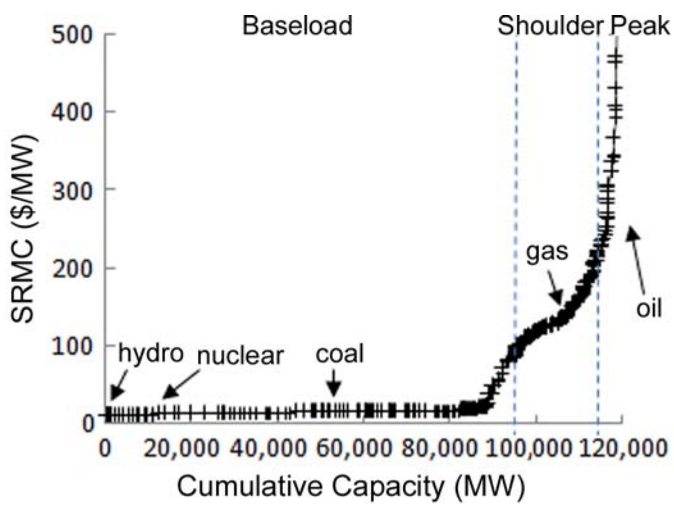

Figure 1. Midwest ISO short run marginal cost curve [21]. Each tick mark represents an additional plant being brought on line to meet growing load as one moves to the right in the curve. The fuel types are indicative, but some high heat rate coal plants may have higher costs than some efficient gas plants, for example.

Because there are transmission, distribution, and other costs, consumers see electricity prices that are higher than the economic dispatch-based wholesale price. We assume that consumers see prices that reflect the increased cost of generating the electricity. The price varies by customer class due to different markups. The average electricity price by customer class for each region in the analysis, as reported by the EIA [31], and the average markup from the short run marginal cost, or wholesale price (the difference in average retail price from the wholesale price) are shown in Table 1. Using these and the total electricity sales to each customer class, a weighted average markup for each control area is calculated, allowing the average retail price and short run marginal price curve to be estimated from the economic dispatch.

Table 1. Average electricity price and markup by customer class (2005) [31]

	PJM	ERCOT	MISO
Average price by customer class (cents/kWh)			
Wholesale	5.4	5.5	4.0
Residential	12.5	10.9	8.4
Commercial	11.8	8.9	7.7
Industrial	7.3	7.1	4.9
Markup from wholesale (cents/kWh)			
Residential	7.1	5.4	4.4
Commercial	6.4	3.3	3.6
Industrial	1.9	1.6	0.9
Electricity sales by customer class (percent)			
Residential	36	38	33
Commercial	43	33	31
Industrial	21	29	36
Weighted average markup from wholesale (cents/kWh)	5.7	3.6	2.9

ISO data estimated from EIA data reported by NERC region and state

With a price on emitted CO_2, the marginal costs of a generator will increase based on the generator's CO_2 emissions; we assume this cost increase is passed directly to the consumer, resulting in increased electricity prices. As before, the electricity price at any hour is set by the generator at the margin, but with a price on emitted CO_2, marginal costs depend on fuel prices and carbon prices, hence the increase in electricity price paid by consumers depends on the mix of generation technologies and fuels in the region available for dispatch to meet the load (in real time or over a year). We use generator heat rates and CO_2 emission factors from eGRID [21] to construct dispatch curves under a range of carbon dioxide prices. As with the short run marginal cost curve (Fig. 1), we assume for this analysis that the transmission grid has sufficient capacity that economic dispatch (incorporating CO_2 costs) does not create any bottlenecks. The dispatch curves we construct are essentially short run marginal cost curves, reflecting the price of fuel, variable operating costs and price of carbon dioxide emissions for generation in each RTO/ISO.

A significant carbon dioxide price makes minor changes to the dispatch order at moderate load (a few low heat rate gas units displace a few inefficient coal generators). Combining this effect with the demand reduction due to the price increase, we find that for PJM at a price of \$35/tonne CO_2 and an elasticity of -0.1, coal and natural gas use are reduced by 10% and 12% respectively. Details of the calculation are in the online supporting information. In the present partial equilibrium analysis, we do not incorporate the effects of fuel use changes, such as fuel switching, on the price, and caution that a large differential change in prices among fuels will alter the dispatch order. We estimate the effects of natural gas price changes in the next section.

With a price on CO_2 emissions, the price of electricity will increase and consumers will respond to this price increase by lowering their purchases. The literature reports a range of price elasticities [22, 32-34], that are likely to vary among RTO/ISOs. Our elasticity calculations are based on the demand model estimated in [34-36]. Specifically, we assume a constant elasticity aggregate demand function with the following form:

$$P(L) = \beta L^{1/\varepsilon} \tag{1}$$

$$\beta = \frac{P_0}{L_0^{1/\varepsilon}} \tag{2}$$

In equations (1) and (2), $P(L)$ is the demand function, L is the quantity demanded in the system, and ε is the price elasticity of demand. P_0 and L_0 represent price and quantity under zero elasticity (where demand is completely unresponsive to price).

For a given CO_2 price, we calculate the percent increase in retail electricity price, for each hour of historical load and then use a range of short run elasticities to calculate the reduced load (the online supporting information discusses this methodology in detail).

We examine the effects of changes in load due to a carbon price on the total annual carbon dioxide emissions from each area. Because the actual price elasticity of demand is uncertain, we examine the short run change in carbon dioxide emissions in the Midwest ISO, ERCOT and PJM as a function of both the price on CO_2 emissions and the price elasticity of demand. We use historical hourly load data for 2006 in each of the three areas [37-39] and dispatch existing generation to meet the hourly load using economic dispatch under a range of carbon dioxide prices. Hourly carbon dioxide emissions from each dispatched generator are summed over the year and compared to annual CO_2 emissions from generators in the absence of a carbon price. The resulting percentage change in carbon dioxide emissions is calculated for a range of CO_2 prices and elasticities of demand.

Results

The short run retail marginal price with no price on carbon dioxide emissions and with a price of $50 per tonne CO_2 is shown for the Midwest ISO, PJM and ERCOT in Figure 2.

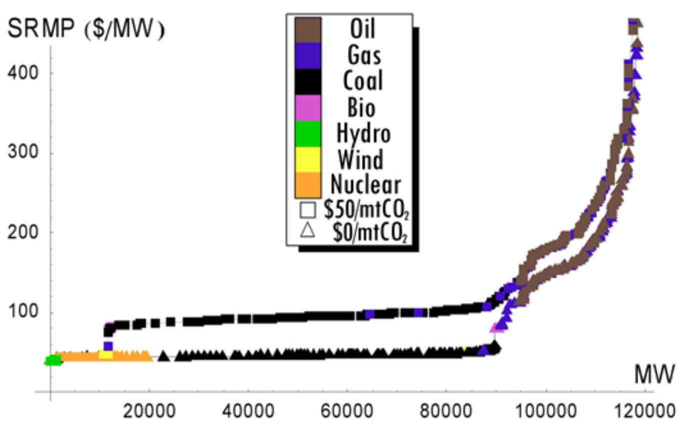

Figure 2(a) Midwest ISO

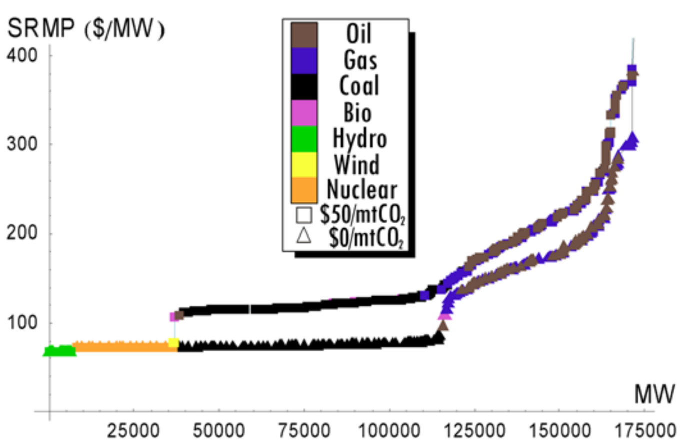

Figure 2(b) PJM

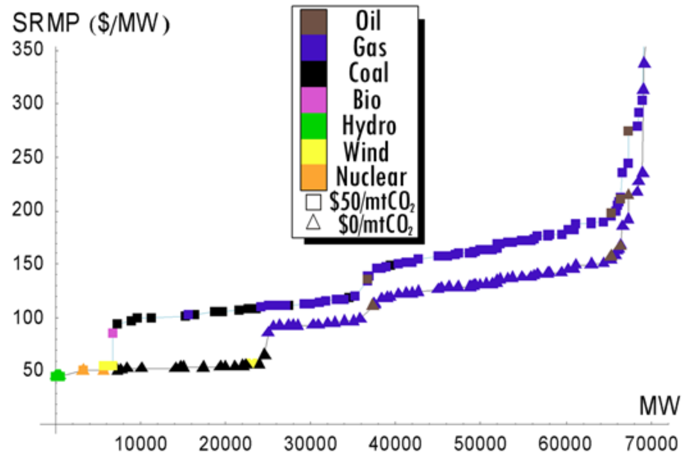

Figure 2(c) ERCOT

Figure 2. Short run retail marginal prices versus cumulative capacity for (a) Midwest ISO (b) PJM and (c) ERCOT. All figures: \$50/tonne CO_2 (top, square) and no price on carbon emissions (bottom, triangle); generator fuel type shown by color.

Low cost, low carbon generators (nuclear and hydro) are generally dispatched first in all regions (although for a carbon price of zero in the Midwest ISO, some coal is dispatched before nuclear (Figure 2a)) while generators with high heat rates and high carbon emissions (oil) are generally dispatched last. The variation in generator marginal costs within the same fuel type (most pronounced for natural gas and oil-fired units) is due to a large variation in generator efficiencies. The increase in electricity price due to a price on carbon depends on the load (Figure 2). At very small loads, there is no change in price since low cost, low carbon generation is dispatched first. In all regions, the largest percentage increases in price are at baseload, because there are large amounts of coal generation. At higher levels of demand (shoulder and peak) the percentage increase in price is less, since generators with lower carbon emissions (natural gas) are dispatched.

In the Midwest ISO, at an emission price for carbon dioxide of \$50 per metric ton, the price of baseload electricity doubles, while the price increase at peak demand is approximately 30% (Figure 2a). Using an elasticity of -0.1, the baseload demand decreases by about 10% and the peak load decreases by approximately 4%. In the Midwest ISO, \$100/MWh is reached at a level of demand less than 20,000 MW (17% of 2006 maximum load) with a CO_2 price of \$50/tonne. The generation mix in PJM contains a large fraction of coal, similar to the Midwest ISO. However PJM has a larger nuclear and natural gas base than the Midwest ISO, resulting in lower baseload generation costs when carbon emissions are priced. The price of electricity remains below $100/MWh in the PJM system, even with a $50/tonne price on carbon dioxide, until dispatch reaches 35,000 MW, or 24% of maximum load (Figure 2b). The generation mix in ERCOT is composed primarily of natural gas and inefficient coal plants with large CO_2 emissions, as reflected in Figure 2c. Prices in ERCOT are generally higher than in either PJM or the Midwest ISO. In ERCOT, $100/MWh is reached at a level of demand less than 10,000 MW (16% of maximum load) with a CO_2 price of $50/tonne.

The percentage reduction in annual carbon dioxide emissions at a range of carbon prices and elasticities is shown in Figure 3 for the Midwest ISO, PJM and ERCOT. We emphasize that these are short run marginal carbon dioxide reductions, reflecting demand reduction in response to higher prices and redispatch of existing generation plants.

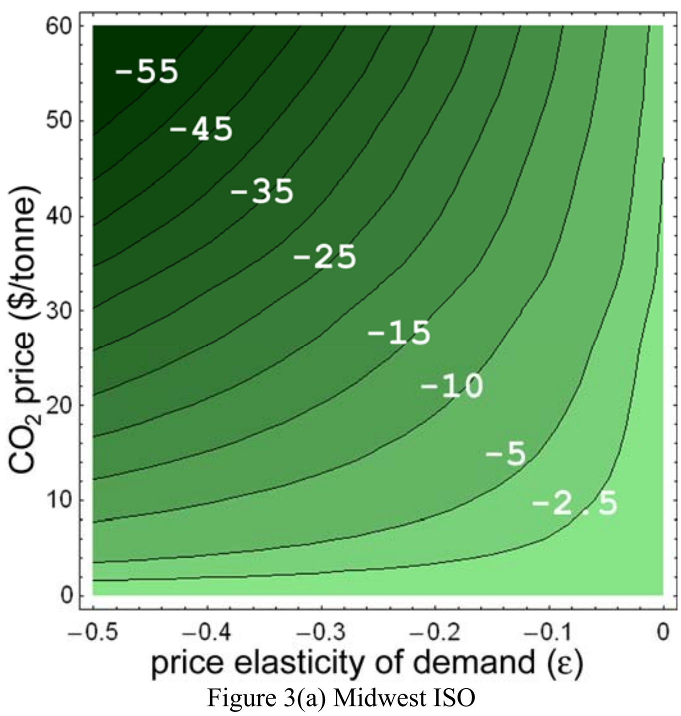

Figure 3(a) Midwest ISO

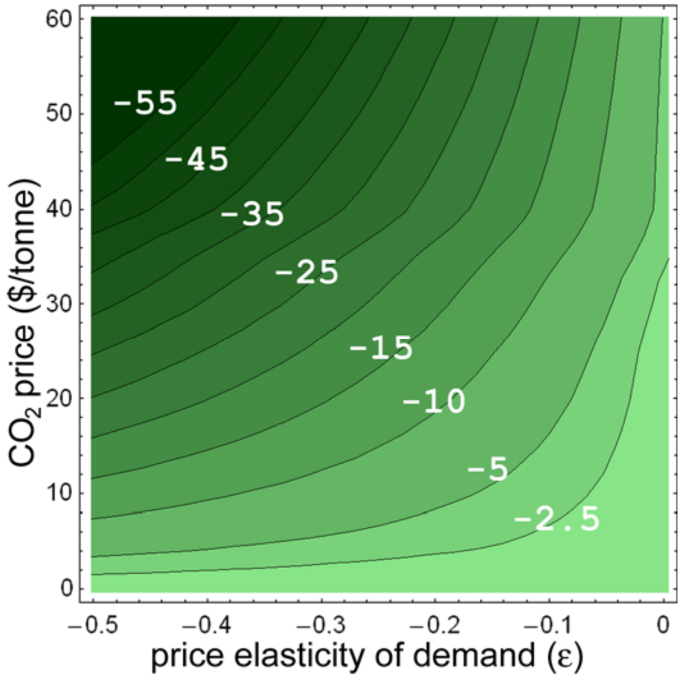

Figure 3(b) PJM

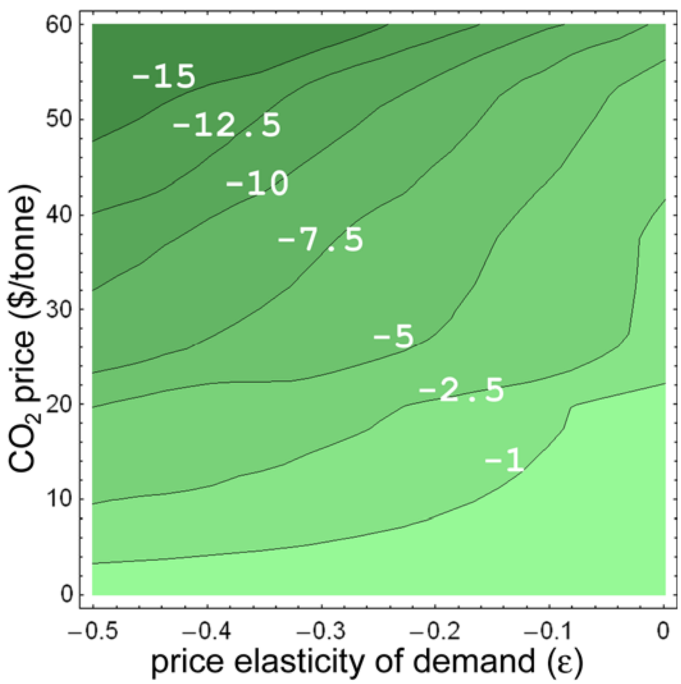

Figure 3(c) ERCOT

Figure 3. Percentage reduction in carbon dioxide emissions for ranges of CO_2 prices and elasticities in (a) Midwest ISO (b) PJM and (c) ERCOT. The contour lines are isoquants corresponding to specific percentage reductions in CO_2 emissions.

Carbon dioxide emissions reductions are almost entirely due to reduced demand rather than a change in dispatch order in the short run, although small changes in the dispatch order are reflected in the reductions seen at zero elasticity in Figure 3. Since the Midwest ISO (Figure 3a) and PJM (Figure 3b) have large amounts of coal generation, the reductions will be larger than in ERCOT (Figure 3c) which relies more heavily on natural gas generation.

The sensitivity of the percentage of carbon dioxide emissions to the price of natural gas is shown in Figure 4.

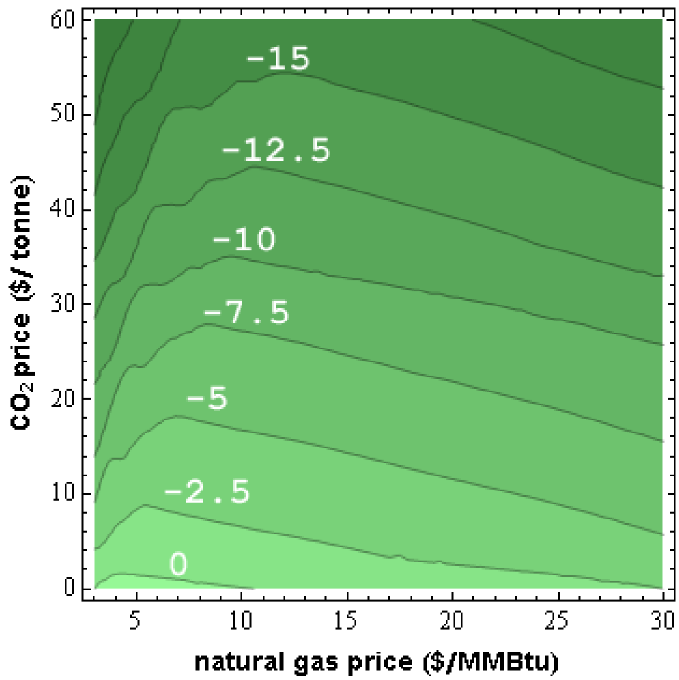

Figure 4(a) Midwest ISO

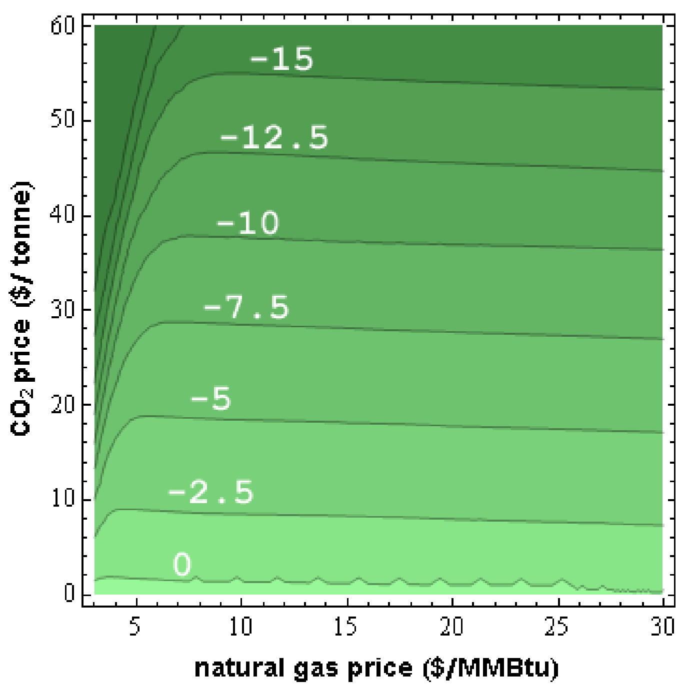

Figure 4(b) PJM

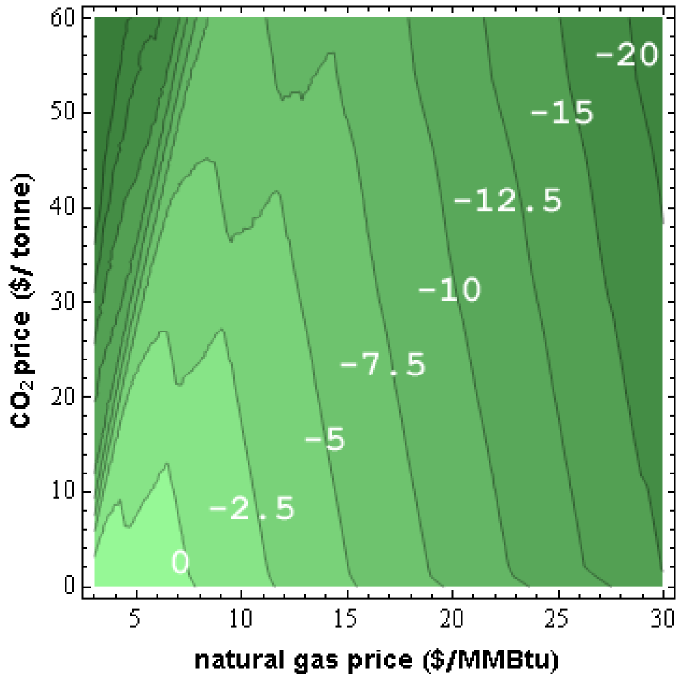

Figure 4(c) ERCOT

Figure 4. Percentage reduction in carbon dioxide emissions for ranges of CO_2 prices and natural gas prices in (a) Midwest ISO (b) PJM and (c) ERCOT. The contour lines are isoquants corresponding to specific percentage reductions in CO_2 emissions for a fixed price elasticity of demand of ε =-0.1.

As Figure 4 illustrates, at very low natural gas prices, carbon dioxide emission reductions are large, since it is economical to dispatch low carbon natural gas units ahead of coal fired units. For any given CO_2 price, as the price of natural gas increases, the CO_2 emission reductions are smaller as it become more costly to dispatch natural gas generation (that is, the contour lines slope up). Because there are natural gas generators in each control area with very high heat rates, at some natural gas price point (~$3-5/MMBtu in MISO and PJM and ~$7-10/MMBtu in ERCOT), these units are underbid by other resources. Although the magnitude of CO_2 emissions reductions may change, the overall results of the analysis are not affected by the price of natural gas, and holding natural gas prices constant does not change the conclusions of the analysis.

Discussion

The short run change in demand that would result from instantaneously imposing a price on CO_2 emissions with no change in the mix of available generation technology, as well as the overall amount of carbon dioxide reduction, varies among ISOs, as shown in Table 2. Control areas with large amounts of carbon intensive generation, such as the Midwest ISO and PJM, are likely to see large CO_2 reductions even with a modest CO_2 price, since demand is reduced at high CO_2 prices.

Table 2. Carbon dioxide reductions at representative values of elasticity (ε) and CO_2 price

parameters		percent CO_2 reduction		
ε	CO_2 price ($/tonne)	MISO	ERCOT	PJM
0	20	1.1	0.2	0.9
0	35	2.0	2.1	2.5
0	50	2.7	3.4	3.9
-0.1	20	5.8	1.2	5.7
-0.1	35	10.1	3.9	10.6
-0.1	50	14.0	6.0	15.6
-0.2	20	10.4	2.3	10.5
-0.2	35	17.9	5.6	18.4
-0.2	50	24.9	8.5	27.2
-0.4	20	19.4	4.1	19.9
-0.4	35	33.0	9.0	34.2
-0.4	50	46.3	13.7	49.9

Regions with a large percentage of natural gas or other low carbon generation such as ERCOT will see relatively small short run decreases in carbon dioxide emissions even at high CO_2 prices and large elasticity. One reason is that there is generally no other lower carbon generator to dispatch ahead of the natural gas that is currently being dispatched. A second reason is that price increases are relatively modest, even with a $50 carbon price.

We have estimated the short run carbon-reduction impacts of a policy where carbon emissions from electric power plants are priced via cap-and-trade or directly taxed, and where all consumers see and respond to prices that reflect the cost of generation. As noted above, the actual imposition of a CO_2 price will likely be gradual, hopefully with a clear time-table that allows utilities and customers to make informed investment decisions. With the proper policy instruments, it may be possible to retrofit old plants as well as accelerate the introduction of new ones; here we assume neither has occurred.

Our analysis covers three regional transmission organizations in the U.S.: PJM, ERCOT and the Midwest ISO. In PJM and the Midwest ISO, short-term carbon reductions of approximately 10% would occur at a \$35/tonne CO_2 and a demand elasticity of -0.1. In ERCOT, only 4% CO_2 reductions would occur under the same conditions.

Thus, if it were imposed instantaneously, a carbon price that has been shown in other work [13-20] to stimulate investment in new generation technology (~\$35/tonne CO_2) would also lead to significant CO_2 reductions via demand response and, to a lesser extent, dispatch order before any new technology was deployed.

Acknowledgements

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Supporting Information

11 pages

4 figures

5 tables

Generation portfolio of ISOs included in the analysis

The three geographic areas analyzed vary in the annual amount of electricity produced and have significantly different portfolios of generation capacity used to meet demand. We use the most recent available data, from 2004. The dispatched generated energy at the present zero carbon dioxide prices is reflected in the MWh column in Table S1. With carbon dioxide constraints, dispatch will be affected by the capacity in each region, reflected in the MW column. The Midwest ISO generation capacity is two-thirds coal. ERCOT's natural gas generators are two-thirds of its capacity, while PJM's capacity is roughly half coal, 30 percent natural gas, and 20 percent nuclear. None of the three has substantial hydroelectric generation. ERCOT has a small fraction of wind.

Table S1. Electricity generation capacity and production by fuel source in 2004 [1]

	MISO [1845 lb CO_2/MWh average]				ERCOT [1519 lb CO_2/MWh average]				PJM [1256 lb CO_2/MWh average]			
	MW	MWh	% MW	% MWh	MW	MWh	% MW	% MWh	MW	MWh	% MW	% MWh
Nuclear	9,424	67,685,529	8.0%	13.5%	5,139	40,435,372	7.3%	17.2%	30,332	232,047,537	17.4%	35.5%
Wind	880	2,087,996	0.7%	0.4%	1,164	2,869,261	1.7%	1.2%	248	146,782	0.1%	0.0%
Hydro	1,327	5,203,463	1.1%	1.0%	521	878,980	0.7%	0.4%	6,199	7,850,440	3.6%	1.2%
Biomass	138	781,199	0.1%	0.2%	30	171,571	0.0%	0.1%	834	4,483,999	0.5%	0.7%
Coal	78,213	418,047,310	66.0%	83.5%	17,777	116,679,710	25.3%	49.5%	78,599	384,951,505	45.2%	58.9%
Natural Gas	25,639	6,619,249	21.6%	1.3%	45,639	74,528,231	64.9%	31.6%	49,923	21,575,626	28.7%	3.3%
Oil	2,879	77,233	2.4%	0.0%	94	456	0.1%	0.0%	7,807	2,698,905	4.5%	0.4%
Total	118,500	500,501,979	100%	100%	70,364	235,563,581	100%	100%	173,942	653,754,794	100%	100%
Peak Load (2006)	116,030				63,056				144,904			

Generator marginal costs

Because marginal costs for generators are not public information, we use estimates for marginal costs [2-4] as well as heat rates and fuel types from the U.S. EPA eGrid database [1] and regionally appropriate assumptions for fuel prices [5] to calculate the unit dispatch (Table S2).

Table S2. Assumed fuel prices and variable costs [1-5]

		PJM[a]	MISO[b]	ERCOT[c]
Nuclear	($/MWh)	16.5	16.5	16.5
Wind[d]	($/MWh)	20	20	20
Hydro	($/MWh)	10	10	10
Biomass	($/MWh)	50	50	50
Coal	($/MMBTU)	1.73	1.41	1.29
Natural Gas	($/MMBTU)	9.95	10.52	7.79
Oil[e]	($/MMBTU)	8.49	11.63	10.45

[a] estimate from EIA MidAtlantic census division including New Jersey, New York, Pennsylvania

[b] from EIA East North Central census division including Illinois, Indiana, Michigan, Ohio, Wisconsin

[c] from EIA Texas state data

[d] excludes production tax credit

[e] Distillate fuel oil includes all diesel, No. 1, No. 2, and No. 4 fuel oils

Calculating price increase and load reduction due to a carbon dioxide price

For a given CO_2 price, we calculate the percent increase in retail electricity price, at each point in the load curve and then use a range of short run elasticities to calculate the reduced load. The steps taken to calculate the price increase, load reduction and overall carbon dioxide emission reductions are illustrated in Figures S1 and S2.

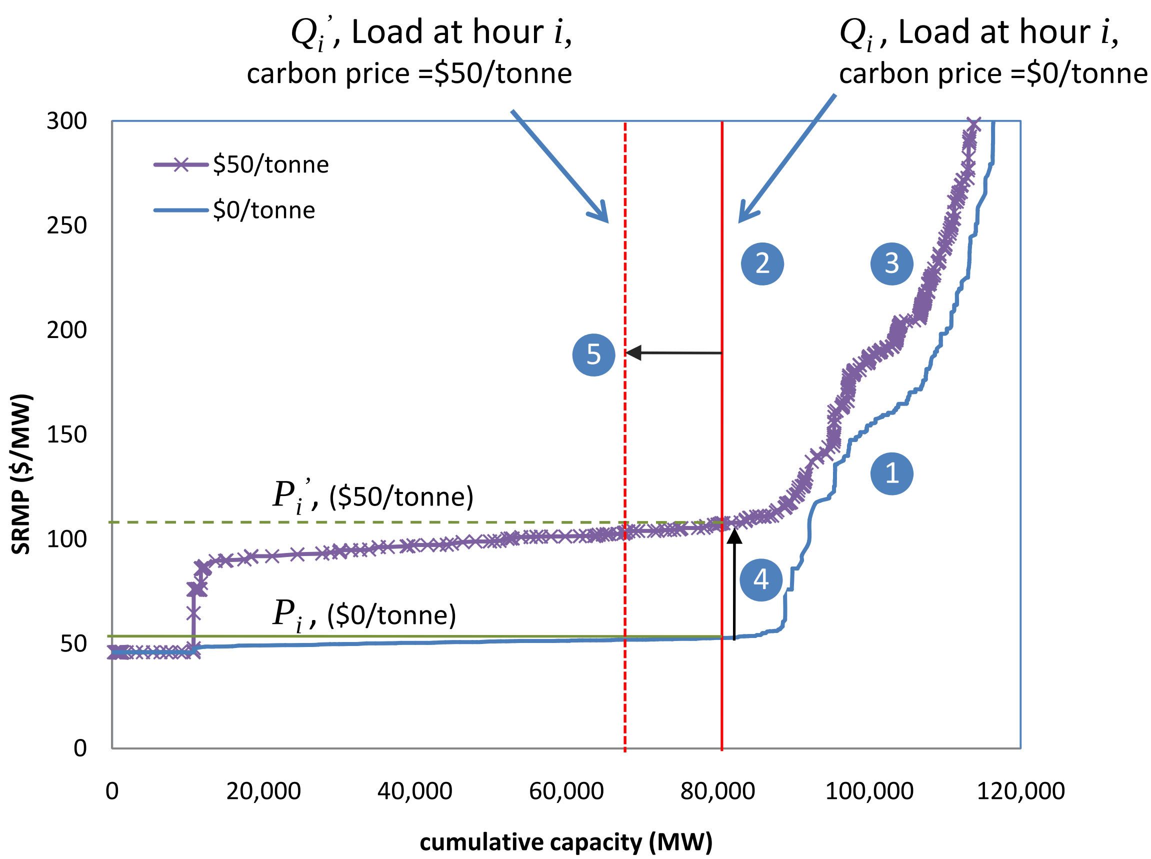

Figure S1. Illustration of the iterative methodology used in the analysis

(1) For each control area, we apply the appropriate weighted average markup from wholesale (Table 1, main text) to obtain a short run marginal price curve for electricity.

(2) We assume that there is a centralized entity (like an ISO) dispatching generation to meet hourly demand, Q_i, and that all customers see a real-time price equal to the marginal cost of the marginal unit (system lambda), P_i. This assumption is equivalent to real-time pricing in a competitive market with a uniform price auction. We use actual, historical hourly demand from 2005 for each ISO.

(3) We use generator heat rates and CO_2 emission factors from eGRID [1] to construct dispatch curves for a given carbon dioxide price. This dispatch curve represents the short run marginal price of generation including the price of carbon dioxide emissions. In some circumstances, it is possible that a sufficiently high carbon price may shift the dispatch order; i.e., a generator positioned higher in the dispatch order (and thus dispatched only at higher levels of demand) may find itself positioned lower in the dispatch order (and thus dispatched more often) following the imposition of a carbon price.

(4) With a price on carbon dioxide emissions, to meet the same load, Q_i, the price paid by consumers increases to P_i'. The percentage price increase is given by $(P_i' - P_i) \times 100 / P_i$

(5) Hourly load is reduced according to the percent increase in electricity price and a given price elasticity. $Q_i' = Q_i \times (1 + ((P_i' - P_i) \times 100 / P_i) \times \varepsilon)$

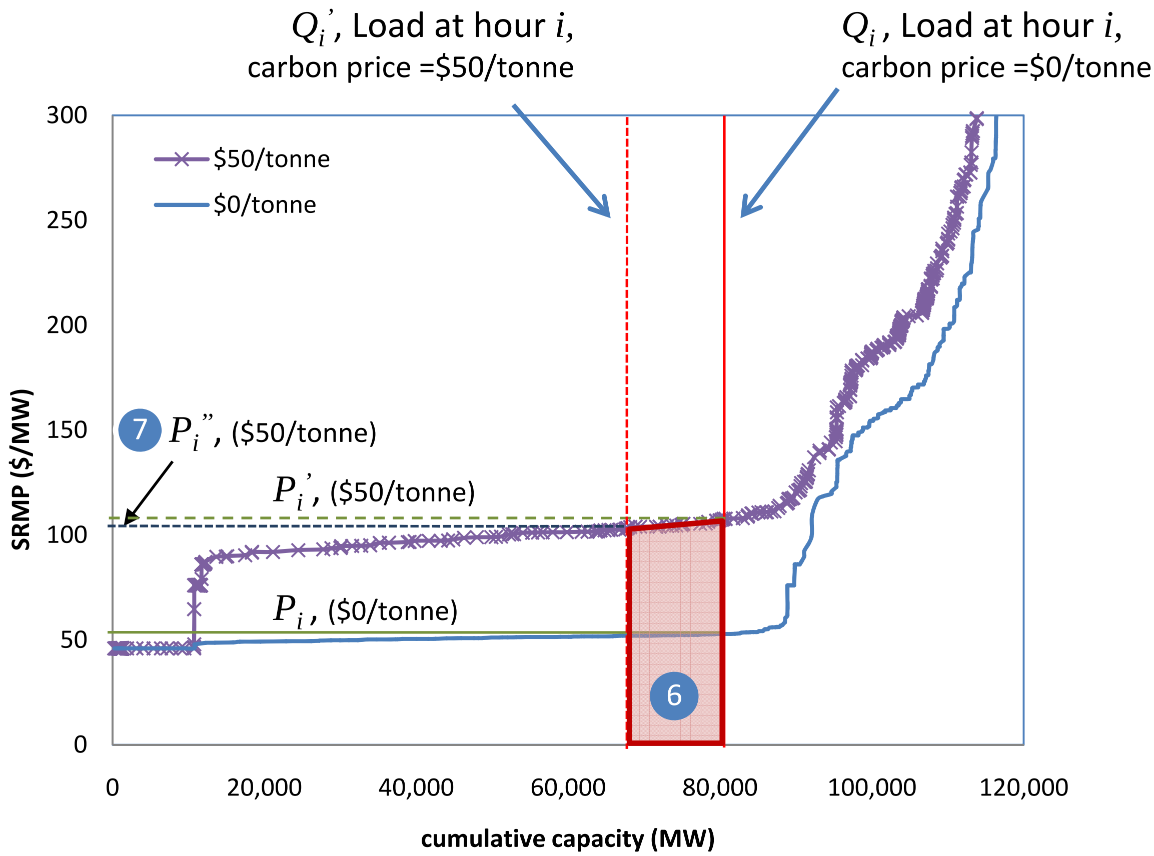

Figure S2. Illustration of the iterative methodology used in the analysis (continued)

(6) The reduction in hourly carbon dioxide emissions due to decreased demand is the sum of all CO_2 emissions from generators between the original load, Q_i and reduced load, Q_i'. The CO_2 emission reductions per hour is the sum over each generator (j) no longer dispatched due to the reduced load(j=Q_i' to Q_i) of the generator output times the hourly CO_2 emissions rate,

$$\sum_{j=Qi'}^{j=Qi} MW_j \cdot CO_2 \text{ emission rate(tonne/MWh)}_j \,.$$

(7) At the reduced demand, Q_i', the new price paid by consumers for electricity is P_i''. We assume the new price (P_i'') and quantity (Q_i'), after taking elasticity into account, represents a new equilibrium quantity and price for the system.

(8) This process is repeated for all 8760 hours of load data for each ISO to find the total amount of CO_2 reductions for a given CO_2 price and elasticity. This process is repeated for ranges of CO_2 prices and elasticities to create a contour plot of CO_2 reductions versus CO_2 price and elasticity.

Figure S3 illustrates how the percent load reduction depends on the load. The figure shows the percent price increase in the Midwest ISO due to a price on carbon dioxide emissions of $50/tonne versus the cumulative capacity, or load.

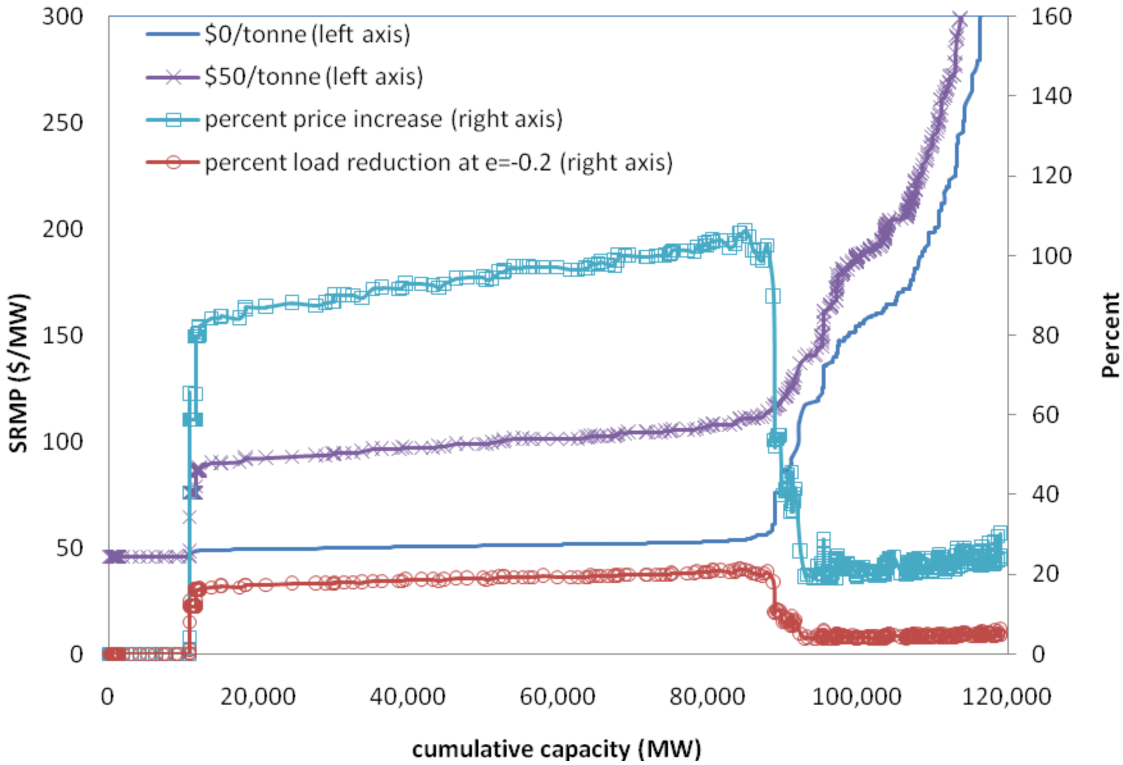

Figure S3. Price increase and load reduction in Midwest ISO with a CO_2 price of $50/tonne and an elasticity of -0.2. Marginal costs have been converted into retail prices using a customer class weighted average for Midwest ISO.

At very small loads, less than about 18,000 MW, there is no increase in the short run marginal price because only carbon dioxide free, hydroelectric, wind and nuclear power is dispatched. At baseload levels of demand, the percent price increase due to carbon dioxide emissions increases as coal fired plants are dispatched to meet the demand. For an assumed elasticity of -0.2, the percent reduction in load due to consumers elasticity is shown in red. For example, if demand is 80 GW at a given hour with no carbon dioxide price, we would expect the load to be reduced by about 18% for that same hour, with a carbon dioxide price of $50/tonne.

Electricity price increase due to a price on carbon dioxide emissions

As Figures S1 and S2 illustrate, a price on carbon dioxide emissions will increase the price of delivered electricity. The increase in hourly price ($P_i'' - P_i$, from Figure S2), depends on the load, price of carbon dioxide and elasticity: baseloads levels of demand have the highest price increases while peak loads see smaller price increases; higher CO_2 prices lead to larger price increases; and larger elasticities lead to smaller price increases. We examine the effect of a carbon dioxide price of $35/tonne on average electricity prices in each ISO.

The average load in each ISO/RTO depends on the season, with highest loads generally occurring in the summer months. Figure S4 shows the seasonal average loads by hour in PJM.

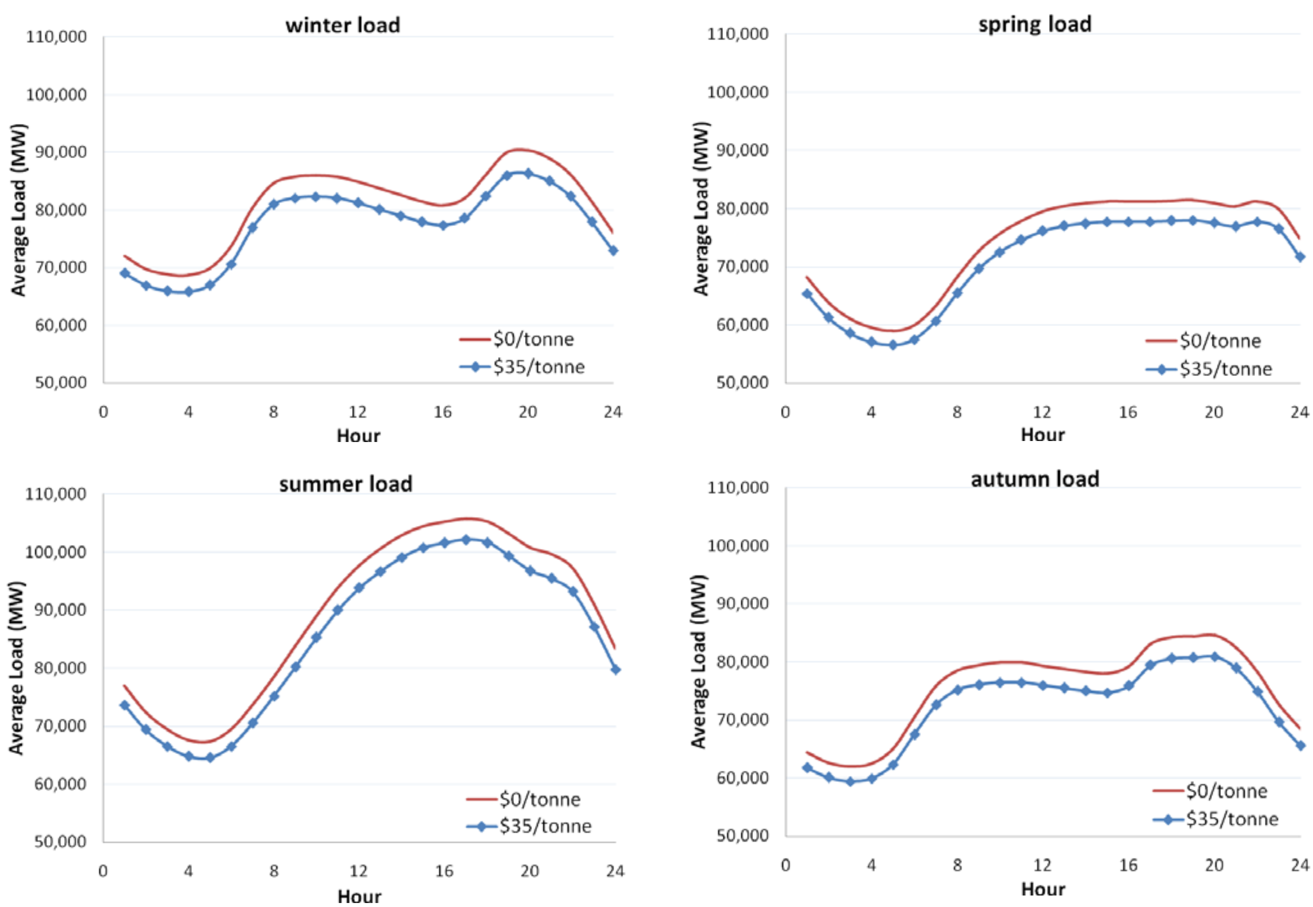

Figure S4. PJM seasonal average load by hour; no carbon dioxide price (top) and $35/tonne CO_2 with an elasticity of -0.1 (bottom)

Using the average percent load reduction, we examined the average hourly increase in electricity price (Table S3).

Table S3. PJM average electricity price ($/MW) by hour at $35/tonne and ε=-0.1

	average SRMC ($/MW)			average SRMP ($/MW)			
Hour	$0	$35/tonne	% SRMC increase	$0	$35/tonne	% SRMP increase	% load reduction (@ ε=-0.1)
1	17.87	48.48	171.3%	74.87	105.48	40.9%	4.09%
2	17.00	47.45	179.1%	74.00	104.45	41.1%	4.11%
3	16.66	46.79	180.9%	73.66	103.79	40.9%	4.09%
4	16.52	46.49	181.5%	73.52	103.49	40.8%	4.08%
5	16.44	46.35	182.0%	73.44	103.35	40.7%	4.07%
6	16.43	46.32	181.9%	73.43	103.32	40.7%	4.07%
7	16.55	46.54	181.3%	73.55	103.54	40.8%	4.08%
8	16.85	47.20	180.1%	73.85	104.20	41.1%	4.11%
9	17.20	47.96	178.8%	74.20	104.96	41.5%	4.15%
10	17.48	48.46	177.3%	74.48	105.46	41.6%	4.16%
11	17.66	48.88	176.7%	74.66	105.88	41.8%	4.18%
12	18.21	49.41	171.3%	75.21	106.41	41.5%	4.15%
13	18.88	49.97	164.6%	75.88	106.97	41.0%	4.10%
14	19.54	50.61	159.1%	76.54	107.61	40.6%	4.06%
15	20.30	51.24	152.4%	77.30	108.24	40.0%	4.00%
16	21.11	51.72	145.0%	78.11	108.72	39.2%	3.92%
17	22.10	52.22	136.3%	79.10	109.22	38.1%	3.81%
18	22.65	52.70	132.7%	79.65	109.70	37.7%	3.77%
19	23.10	53.30	130.8%	80.10	110.30	37.7%	3.77%
20	22.89	53.41	133.4%	79.89	110.41	38.2%	3.82%
21	21.85	52.61	140.8%	78.85	109.61	39.0%	3.90%
22	20.39	51.62	153.1%	77.39	108.62	40.3%	4.03%
23	19.67	50.98	159.2%	76.67	107.98	40.8%	4.08%
24	18.96	50.14	164.4%	75.96	107.14	41.0%	4.10%
Annual average				76.02	106.6	**40.3%**	4.03%

In PJM, imposing an instantaneous price on carbon dioxide emissions of $35/tonne will lead to a price increase of approximately 40 percent at an assumed elasticity of -0.1. The results of repeating the same procedure for the Midwest ISO and ERCOT are shown in Table S4.

Table S4. Average annual SRMP ($/MW)

RTO/ISO	\$0/tonne	ε=-0.1, \$50/tonne	Percent increase	ε=-0.1, \$35/tonne	Percent increase
PJM	76.02	119.48	57.17	106.63	40.3
ERCOT	102.23	127.33	24.55	119.70	17.1
Midwest ISO	63.66	107.28	68.52	94.00	47.7

The price increase due to a \$35/tonne price on carbon dioxide emissions is largest in the Midwest ISO (48%) and smallest in ERCOT (17%) at an elasticity of -0.1.

Changes in fuel use

A price on carbon dioxide emissions will change the amount of coal and natural gas generation in each ISO. If fuel mix changes lead to increased demand for certain fuels, there may be significant cost increases. We examined the changes in annual coal and gas generation in each ISO across the ranges of elasticities and carbon dioxide prices (Table S5). We calculate the amount of coal and natural gas generation (MWh) needed to meet the 2005 historical annual load for each ISO at a given elasticity and CO2 price, and make comparisons to the generation needed when there is no CO_2 price.

Table S5. Percent change in annual coal and gas generation (MWh) at representative values of elasticity (ε) and CO_2 price

parameters		Percent change					
	CO_2 price	MISO		ERCOT		PJM	
ε	(\$/tonne)	Coal	NG	Coal	NG	Coal	NG
0	20	-1.0	1.5	-0.2	0.1	-0.7	4.9
0	35	-1.8	5.8	-2.1	3.4	-2.6	5.9
0	50	-2.5	31.0	-4.0	6.5	-4.3	11.0
-0.1	20	-5.1	-9.2	-0.6	-2.9	-5.2	-4.9
-0.1	35	-8.9	-13.7	-2.8	-1.9	-10.1	-11.6
-0.1	50	-12.6	-4.7	-5.1	-0.9	-15.4	-14.4
-0.2	20	-9.2	-19.0	-1.0	-5.9	-9.8	-14.7
-0.2	35	-16.0	-30.4	-3.4	-7.3	-17.5	-25.5
-0.2	50	-22.7	-27.6	-6.0	-8.5	-26.7	-33.4
-0.4	20	-17.5	-36.6	-1.7	-11.7	-18.8	-30.8
-0.4	35	-30.4	-55.8	-4.6	-17.5	-32.8	-50.6
-0.4	50	-43.6	-64.3	-8.3	-22.8	-49.3	-64.6

At zero elasticity and a significant carbon price, there are minor changes to the dispatch order at moderate load (a few low heat rate gas units displace a few inefficient coal generators) and the amount of natural gas generation increases while the amount of coal generation decreases. When there is any elasticity of demand, a price on CO_2 emissions leads to an overall decreased demand and reductions in both natural gas and coal generation. Based on this partial equilibrium analysis, at typically cited values for elasticity, a price on CO_2 emissions would not increase prices for coal or natural gas fuels.

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