INFERRING CARBON ABATEMENT COSTS IN ELECTRICITY MARKETS: A REVEALED PREFERENCE APPROACH USING THE SHALE REVOLUTION
(CULLEN AND MANSUR)
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APPENDIX FOR ONLINE PUBLICATION

A1. Coal Price Regressions

Section III of the text discusses the method we use to calculate a coal price index. Here we report the regression results for each region (see Table A.1). We also show the national average for comparison. While the type of coal a power plant purchases may change in response to natural gas prices, we are concerned that the heterogeneity in coal transactions within a plant may also reflect noise. So, we construct a coal price index based on the average coal characteristics in a region as of January 2001. We then add the monthly fixed effects to the base price, thereby keeping the coal composition constant for a region. This coal price index in shown in Figure A.1.

Table A.1—: Coal Price Index Regression Results

Variable	National	East	West	ERCOT
Sulfur	-13.59***	-13.59***	-10.51*	1.40
	(1.38)	(1.36)	(5.77)	(12.86)
Ash	2.09***	2.69***	-1.53***	0.40
	(0.26)	(0.33)	(0.35)	(2.00)
Mine	-7.99***	-10.88***	19.31***	32.33***
	(1.81)	(1.88)	(5.99)	(7.13)
Btu	4.40***	4.37***	5.33***	5.24*
	(1.40)	(1.42)	(0.95)	(3.09)
Month-Year F.E.	Yes	Yes	Yes	Yes
Plant F.E.	Yes	Yes	Yes	Yes

A2. Robustness to Function of Relative Fuel Costs

Figure A.2 estimates the level of emissions in the East as a function of fuel prices using three different functional forms of relative fuel prices. They are (1) our main specification of coal/gas ratio, (2) the inverse ratio of gas/coal, and (3) the price difference of the natural gas price minus the coal price (in \$/mmBTU). All three ratios show very similar mappings of gas prices to emissions, holding coal prices fixed.

A3. Robustness to the Number of Knots

The main results use six knots in the cubic splines of several variables, including the cost ratio. Figure A.3 shows how the predicted emissions in the East change with the number of knots in comparison to Figure 6a. We see that for four and five knots, the results are virtually identical to the model with six knots and lie completely within the 95% confidence of the six knot specification. For the model with only three knots, the emissions response is overstated at high gas prices, where there are few observations. This model also smoothes over the sharp drop in emissions around

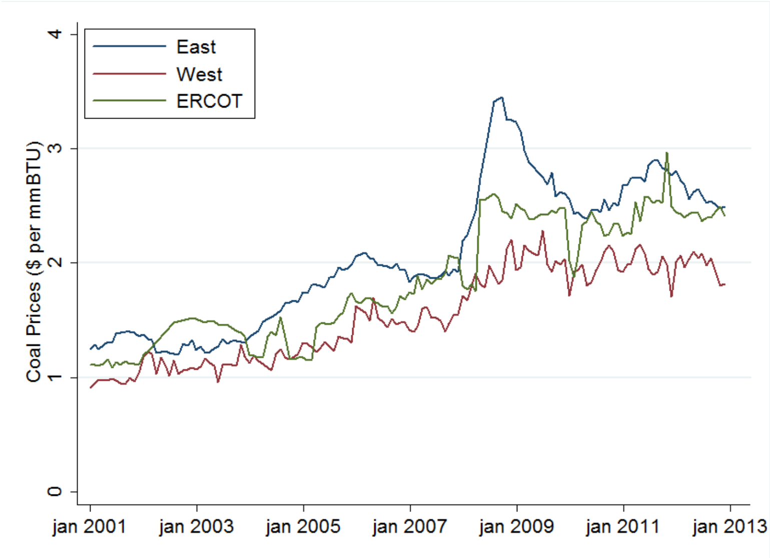


Figure A.1. : Monthly Coal Price Indices

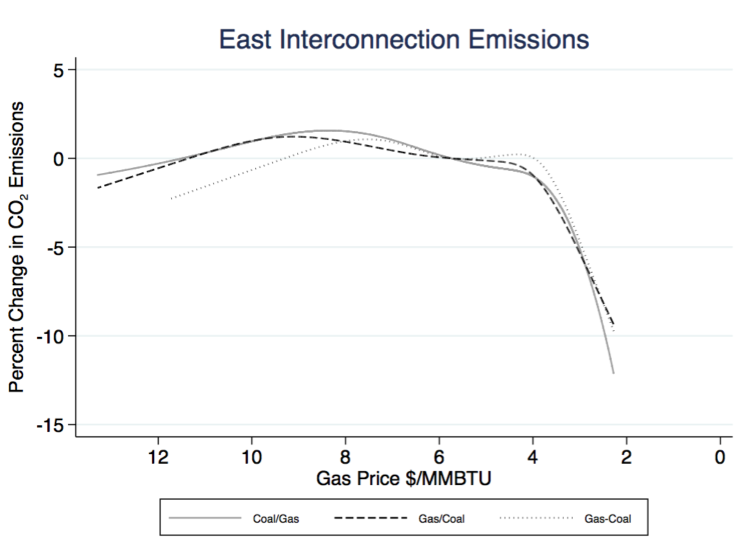


Figure A.2. : Robustness to Functional Form of Fuel Costs

\$5/mmBTU. The model with seven knots is more sensitive to noise in the data that leads to non-monotonicity in the response curve. It is also almost entirely within the 95% confidence interval of the six knot specification. Overall, the results are qualitatively and statistically insensitive to the number of knots used to form the cubic spline.

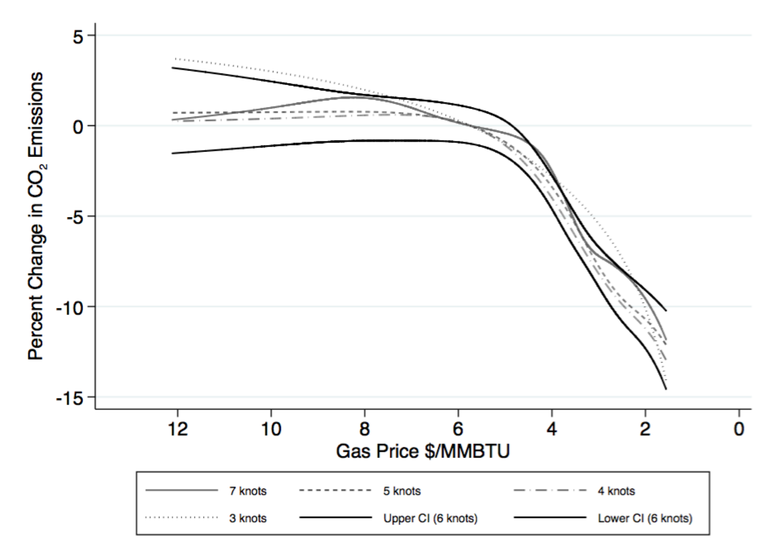


Figure A.3. : Robustness to Number of Knots

A4. Electricity Demand

Our analysis does not account for the change in electricity demand that may occur when equilibrium electricity prices increase under a carbon price. Although we cannot impute the demand response to higher counterfactual electricity prices, we can understand how a price on carbon would affect emissions if demand were lower. We do this by splitting the sample by the median daily demand in each month of the sample. That is, we define high demand days in a month to be those days whose demand is higher than the median demand in that month. Low demand days are those below the median. We do this by month of sample to avoid selection on seasonality or time trend. That is, we avoid comparing only winter months to only summer months or the beginning of the sample to the end of the sample. In a month, some days will be happen to be higher demand due to weather and other shocks to demand. This limits the difference in demand between the high and low demand groups, but ensures a comparable sample. The average difference between the high and low demand sample is about 10% of demand as shown in Table A.2. This can be seen in the kernel densities of the two regimes. Figure A.4a shows the density of demand has a similar shape but shifts in the high and low demand regimes. Although there is a shift in the distribution of demand, the distribution of gas/coal cost ratios is almost identical in the two regimes as shown in Figure A.4b. We use the same specification used for our main results to estimate the response of emissions to variation in the cost ration in both the high demand and the low demand sample. The results, shown in Figure A.5, demonstrate that there is very little difference between the high and low demand samples. Only in ERCOT at very low gas prices is there a divergence. As we would expect, low demand implies a higher response to relative prices.

Table A.2—: Average Daily Demand (GWh) in High and Low Demand Samples

	Low	High	% Difference
East	7053	7855	10.2
ERCOT	810	922	12.2
West	1758	1910	8.0

(a) Demand (b) Gas/Coal Ratio

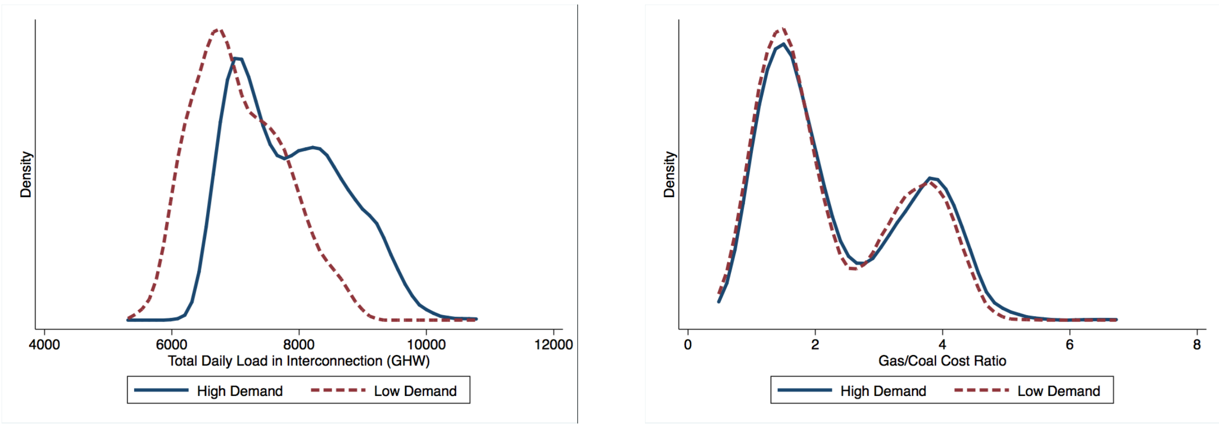


Figure A.4. : Distributions by Demand Regime: Eastern Interconnection

A5. Gas Prices and Coal/Gas Cost Ratio

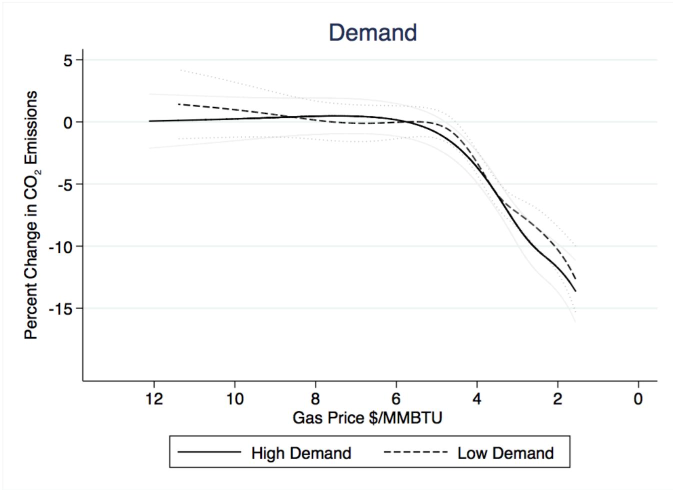
For comparison with the coal prices, Figure A.6 shows variation in gas prices over time for each of the three regions. Figure A.7 shows the variation in the ratio of the coal to gas price which is the variable of interest in our estimation procedure. Both gas prices and the ratio show substantial variation over time and across regions. Even in later time periods we see substantial variation in the coal to gas price ratio. Even after 2010 we have cost ratios that range between 0.5 and 1.25. These correspond to carbon prices less than \$10 and greater than \$100 at our baseline prices for gas and coal.

A6. Simple Model of Potential Fuel Switching

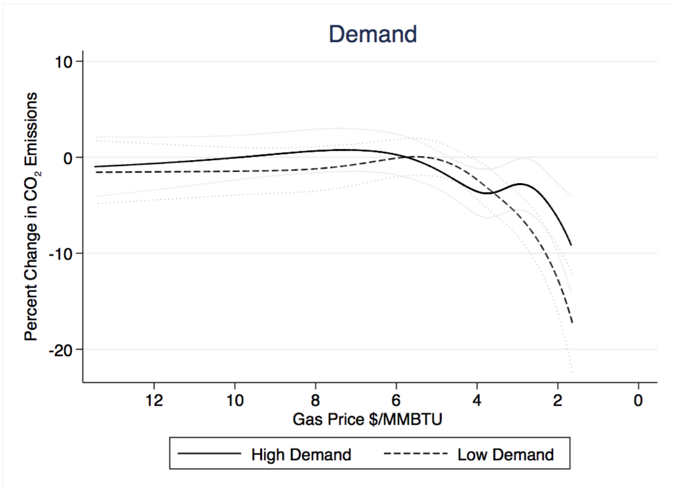
Here we describe the methodology used to calculate the potential for fuel switching. First we calculate the total electricity generated (gen_{ift}) in interconnection i, fuel type f, and hour of sample t:

$$gen_{ift} = eiagen_{ifm} \cdot \frac{cemsgen_{ift}}{\sum\limits_{t \in m} cemsgen_{ift}},$$

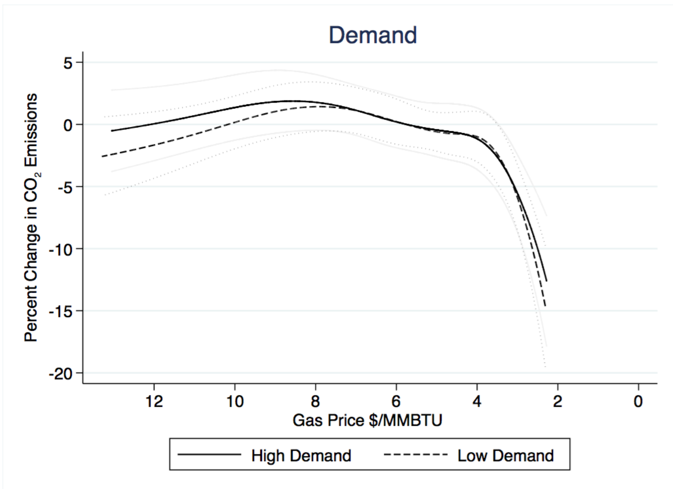
where $eiagen_{ifm}$ is the aggregate monthly net generation reported in EIA form-923 and $cemsgen_{ift}$ is the hourly gross generation reported by CEMS. In other words, we use the variation within a month reported by CEMS to distribute the EIA monthly generation. We use a second measure of hourly generation ($\widetilde{gen}_{ift}$) based on heat input data from CEMS to allocate $eiagen_{ifm}$ across hours in a month: $\widetilde{gen}_{ift} = eiagen_{ifm} \cdot (cemsheat_{ift} / \sum\limits_{t \in m} cemsheat_{ift})$, where $cemsheat_{ift}$ is the hourly



(a) Eastern Interconnection



(b) ERCOT Interconnection



(c) Western Interconnection

Figure A.5. : CO_2 Response in High and Low Demand Periods

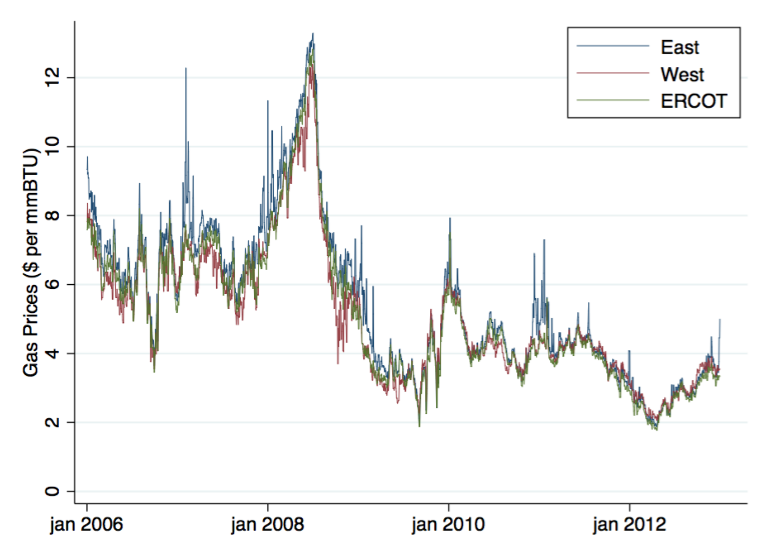


Figure A.6. : Daily Gas Price Index by Region

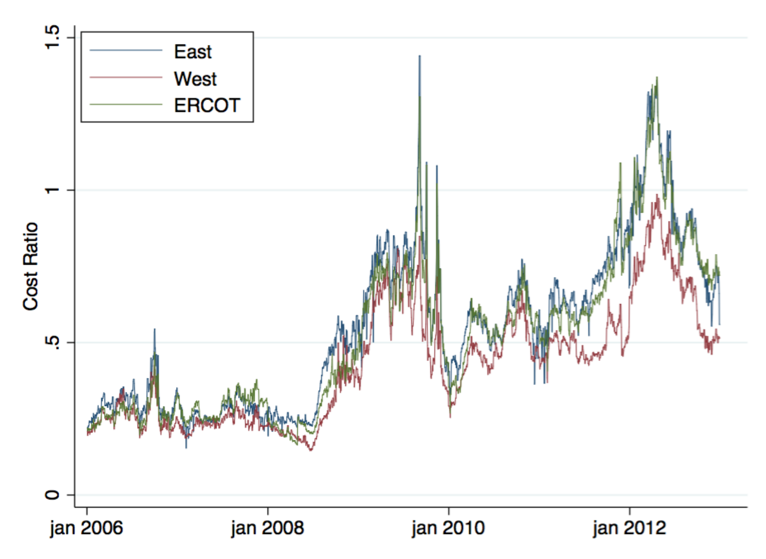


Figure A.7. : Coal/Gas Price Ratio by Region heat input reported by CEMS. The results are quite similar.

Next we calculate the nameplate capacity by fuel type, month, and interconnection. We define unused capacity as the difference between hourly generation and available capacity, where available capacity is nameplate capacity that is derated to account for the fact that power plants shut down for routine maintenance of because of forced outages. We test the robustness of our calculations to several different derating factors (75% to 100% for each 5% increment).

Finally, we calculate the carbon implications by comparing the unused capacity of natural gas plants within an interconnection and hour with the contemporaneous generation from coal-fired power plants. For each hour and interconnection, we calculate the generation from coal generators that could be reallocated to idle natural gas capacity. This produces a measure of potential fuel switching. Surprisingly, in most hours, we find that there is substantial unused gas capacity to completely offset all coal generation, even for low derating rates. In order to convert generation into potential carbon reductions, we use the emissions factors mentioned in footnote 6 of the text and the average heat rate by year, interconnection and fuel type: $(\sum_{m\in yr} eiaheat_{ifm} / \sum_{m\in yr} eiagen_{ifm})$, where $eiaheat_{ifm}$ is the aggregate monthly heat input reported in EIA form-923 for interconnection i, fuel type f, and month m in year yr.

Note that this calculation makes many assumptions about transmission capacity, power plant operation capabilities, information, and incentives that we argue in Section I of the text were unreasonable and motivation for a more careful analysis that we revisit Section IV. Nonetheless, we report the simple model in order to get a sense of how much unused gas capacity is available.

Table A.3 shows the potential reduction in carbon emissions by year for two derating rates, 90% and 80%. The paper reports the results just for 2012 with a derating rate of 90%.

Table A.3—: Potential Shares of Carbon Emissions Reduced from Fuel Switching

	Derate at 90%			Derate at 80%		
Year	East	ERCOT	West	East	ERCOT	West
2001	0.28	0.31	0.26	0.24	0.30	0.21
2002	0.37	0.33	0.40	0.33	0.33	0.38
2003	0.44	0.34	0.41	0.41	0.34	0.40
2004	0.47	0.39	0.42	0.44	0.39	0.41
2005	0.46	0.39	0.44	0.43	0.39	0.43
2006	0.45	0.39	0.42	0.43	0.38	0.42
2007	0.45	0.39	0.41	0.42	0.39	0.40
2008	0.46	0.39	0.41	0.44	0.38	0.41
2009	0.47	0.39	0.41	0.45	0.38	0.40
2010	0.44	0.40	0.43	0.42	0.40	0.43
2011	0.45	0.40	0.44	0.42	0.39	0.44
2012	0.42	0.37	0.40	0.41	0.36	0.40

A7. Results and Data Distribution

Here we take the results shown in Figures 6 and 7 of the text, and overlay histogram of variable of interest to show the density of data that identify the curve. We also show the location of the knot points used in estimation. These are shown for the East electricity generation region, but the pattern is similar in the West and ERCOT. Figure A.8, shows the results as gas prices decrease with the coal price fixed at the long run base case as in Figure 6a. The six knot points spaced according to the distribution of the cost ratio at the 5, 23, 41, 59, 77, 95 percentiles. Importantly, the histogram shows that the data are dense in the areas where the gas price is relatively low. Identifying the response of generators to low gas prices is what allows the model to make predictions about the response of generators to a price on carbon.

Figure A.9 transforms the results be a function of carbon prices as detailed in the body of the paper. The curve is identical to the one in Figure 7a, but with percentage change on the y-axis. We again have imposed the knot points and the histogram of the data onto the estimated response curve. There are many data points up through about \$60/ton after which the density of the data begins to be stretched out. Note that only 5 knot points show up in this graph. This because we only report the results for carbon prices less than \$80/ton. There are implied carbon prices in excess of \$200/ton, but the data are sparse for higher carbon prices. Thus, we have to rely more on the function form to identify the behavior of generators for very high carbon prices. Also, these prices are less interesting from a policy perspective. For comparison, the results over the full range of implied carbon prices is shown in Figure A.10.

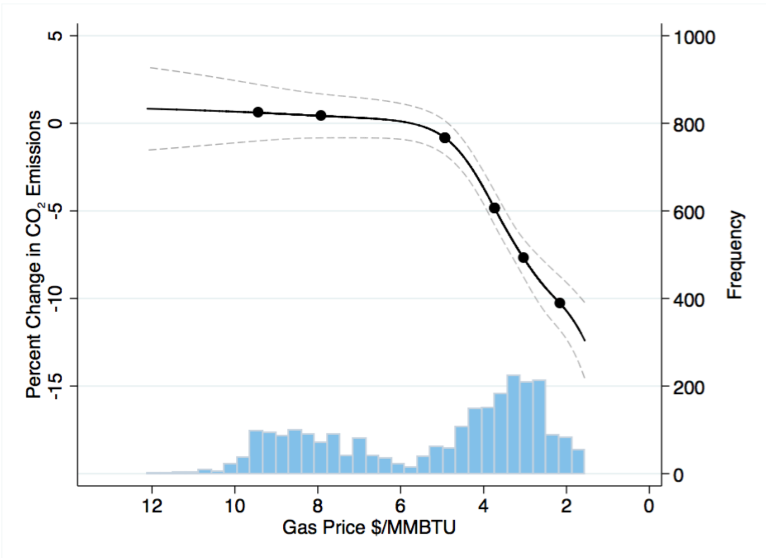


Figure A.8. : Estimated CO_2 Response to Fuel Prices

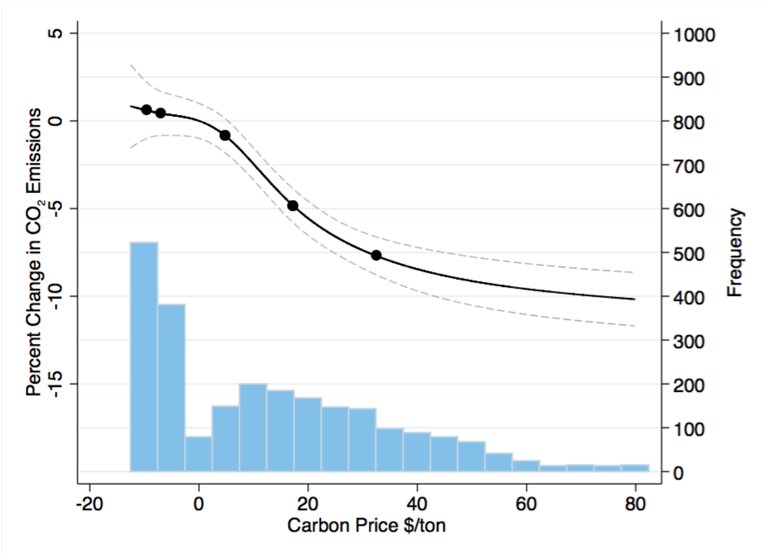


Figure A.9. : Imputed CO_2 Response to Carbon Prices

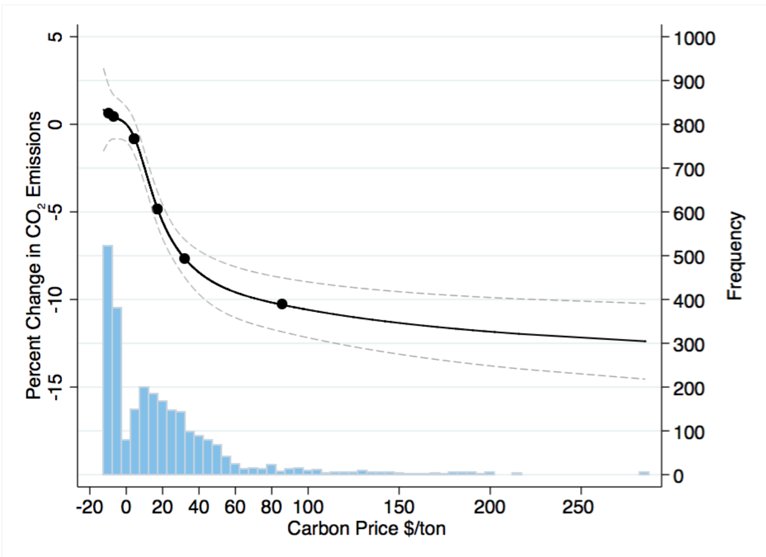


Figure A.10. : CO_2 Response for Full Range of Imputed Carbon Prices

A8. Parameter Estimates

Table A.4 presents the parameter estimates and Newey West standard errors that allow for a seven-day lag structure for our main results. Variables which are represented as a restricted cubic spline have five parameters associated with them. These five parameters are associated with transformed versions of the original variable. The transformation incorporates the choice of the knot points and the restrictions on the cubic spline. Due to their transformation, the individual parameters do not have a straightforward interpretation. However, we report the estimates for completeness and replicability.

Table A.4—: Parameter Estimates

	East		ERCOT		West	
Variable	Coef.	S.E.	Coef.	S.E.	Coef.	S.E.
Price Ratio 1	-205218	(521921)	93719	(62411)	352024	(160581)
Price Ratio 2	4760365	(1.75e+07)	-2142828	(2260089)	-8828279	(5094672)
Price Ratio 3	-1.33e+07	(2.42e+07)	2385139	(4171850)	1.29e+07	(8159820)
Price Ratio 4	2.16e+07	(1.17e+07)	910225	(2701735)	-4620928	(4988153)
Price Ratio 5	-1.55e+07	(9142587)	-2379661	(1601897)	-764223	(3604246)
Daily Load 1	.788	(.0416)	.42	(.0438)	.37	(.0515)
Daily Load 2	-.189	(.295)	.921	(.955)	-.0982	(.371)
Daily Load 3	-.329	(1.53)	-3.05	(2.63)	-1.7	(2.31)
Daily Load 4	1.65	(2.19)	3.09	(2.44)	5.94	(4.06)
Daily Load 5	-1.76	(1.41)	-1.16	(1.1)	-6.14	(2.99)
Std Dev Load	-10.8	(2.75)	9.55	(2.42)	-2.76	(3.24)
Max Load	2.72	(.9)	-1.48	(.803)	1.99	(1.14)
Min Load	-6.36	(1.3)	4.8	(1.26)	-1.41	(1.2)
Temperature 1	-15753	(2128)	67.7	(399)	-1900	(803)
Temperature 2	48711	(11663)	-1117	(1580)	-969	(6152)
Temperature 3	-131112	(46188)	-1303	(6788)	14344	(23569)
Temperature 4	210643	(76370)	26024	(16414)	-15611	(33735)
Temperature 5	-61719	(104930)	-61978	(29001)	17179	(29878)
Non-fossil	.0101	(.00167)	-.0133	(.00172)	-.00813	(.000674)
Electricity Imports	.0548	(.0146)			.0142	(.006)
SO_2 Prices	-280	(71.7)	53.6	(10.1)	40.4	(21.1)
F.E. 2006 Q2	-176292	(38052)	5511	(8404)	-25670	(17796)
F.E. 2006 Q3	-328363	(46541)	30799	(7180)	53294	(16994)
F.E. 2006 Q4	-99481	(78366)	38940	(6989)	90511	(17635)
F.E. 2007 Q1	-289146	(69998)	28511	(8359)	43597	(20572)
F.E. 2007 Q2	-124088	(53675)	31097	(7367)	18065	(19651)
F.E. 2007 Q3	-198244	(51447)	35511	(8034)	55407	(19871)
F.E. 2007 Q4	-51159	(51394)	45189	(7095)	78231	(18779)
F.E. 2008 Q1	-217079	(62074)	40065	(8723)	48960	(18903)
F.E. 2008 Q2	-282016	(73059)	82441	(10525)	49589	(24150)
F.E. 2008 Q3	-488521	(74887)	78210	(11649)	80486	(25276)
F.E. 2008 Q4	-150002	(73451)	59770	(12654)	97737	(26246)
F.E. 2009 Q1	-381247	(84577)	46438	(13461)	68137	(27406)
F.E. 2009 Q2	-175991	(86804)	61084	(14322)	-6509	(30209)
F.E. 2009 Q3	-408618	(94665)	68576	(14683)	90599	(30585)
F.E. 2009 Q4	-319035	(85683)	76810	(13658)	95831	(28526)
F.E. 2010 Q1	-533501	(86725)	51957	(13920)	49514	(27808)
F.E. 2010 Q2	-274691	(89587)	68685	(16532)	26262	(30891)
F.E. 2010 Q3	-437117	(88881)	93294	(14893)	95810	(29840)
F.E. 2010 Q4	-242801	(85932)	91877	(14820)	79171	(30085)
F.E. 2011 Q1	-483165	(90909)	91413	(14985)	-385	(33313)
F.E. 2011 Q2	-277878	(88872)	99518	(15075)	-71088	(30391)
F.E. 2011 Q3	-473267	(101035)	107840	(15263)	19183	(32634)
F.E. 2011 Q4	-506237	(95251)	88076	(14744)	52658	(31134)
F.E. 2012 Q1	-693847	(102784)	64690	(15812)	60991	(33189)
F.E. 2012 Q2	-475982	(100653)	66837	(18255)	207	(34720)
F.E. 2012 Q3	-644173	(106752)	90908	(15769)	33146	(34896)
F.E. 2012 Q4	-577845	(96159)	85238	(15545)	76350	(30975)
Constant	643968	(335912)	62601	(41208)	316994	(109735)
Observations	2557		2557		2557	
R^2	0.980		0.954		0.938	

Standard errors in parentheses

Notes: Load is daily load; Non-fossil is non-fossil generation; Temp is temperature; Imports is Canadian net imports of electricity. F.E. is time fixed effect.

A9. Co-pollutants

This section complements the analysis shown in Figures 9 and 10 of the text by examining how the effects of SO_2 and NO_x are disbursed spatially. The EPA subregions of the US are showing graphically in the Figure A.12 . Figure A.11 shows how a price of $20 per ton of carbon dioxide would affect CO_2, SO_2, and NO_x emissions in each region. The methodology is identical to that described in the paper. In particular, note that the independent variables are still at the interconnection level.

We see from the figure that the emissions response varies regionally. The subregions SRVC (the North Carolina, South Carolina, and Virginia region), RFCE (the New Jersey, Maryland, Delaware, and eastern Pennsylvania region), and NEWE (New England) show the largest reductions of about ten percent for CO_2.

However, this does not lead to the largest percent reductions in local pollutants. The co-benefits (in percentage terms) are largest in SRVC and SRSO (the Alabama and Georgia region) for NO_x, and NEWE, SRVC, and CAMX (California) for SO_2. Note that California has very little SO_2. The regional responses of three pollutants are positively correlated across pollutants. However, they do show very different patterns.

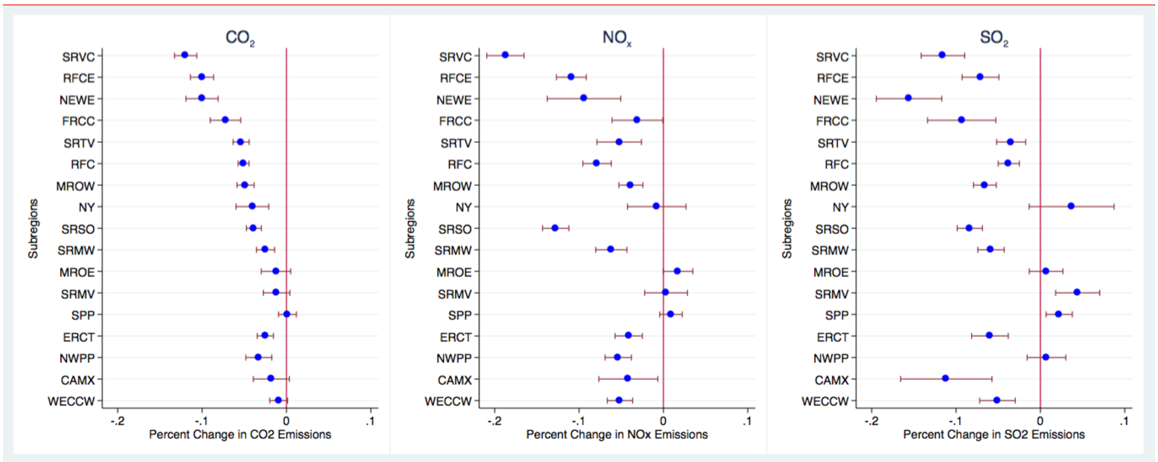


Figure A.11. : Emissions Response to Carbon Price by Subregion

A10. Sensitivity Analysis

Here we test the sensitivity of our main results. Table A.5 show the robustness results for each Interconnection to the controls of the model. The predicted percent change in emissions at a $20 carbon is used as the benchmark value. The first column uses no controls, but includes season-of-sample fixed effects. Further columns add controls for electricity load, temperature, non-fossil generation, electricity imports and sulfur dioxide permit prices. The final column, which includes all controls, is the preferred specification used for the main results in the paper. In each interconnection, failing to control for electricity demand shocks leads to a much higher estimates of emissions reduction due to a carbon price. Other controls tend to mitigate the estimated effects,

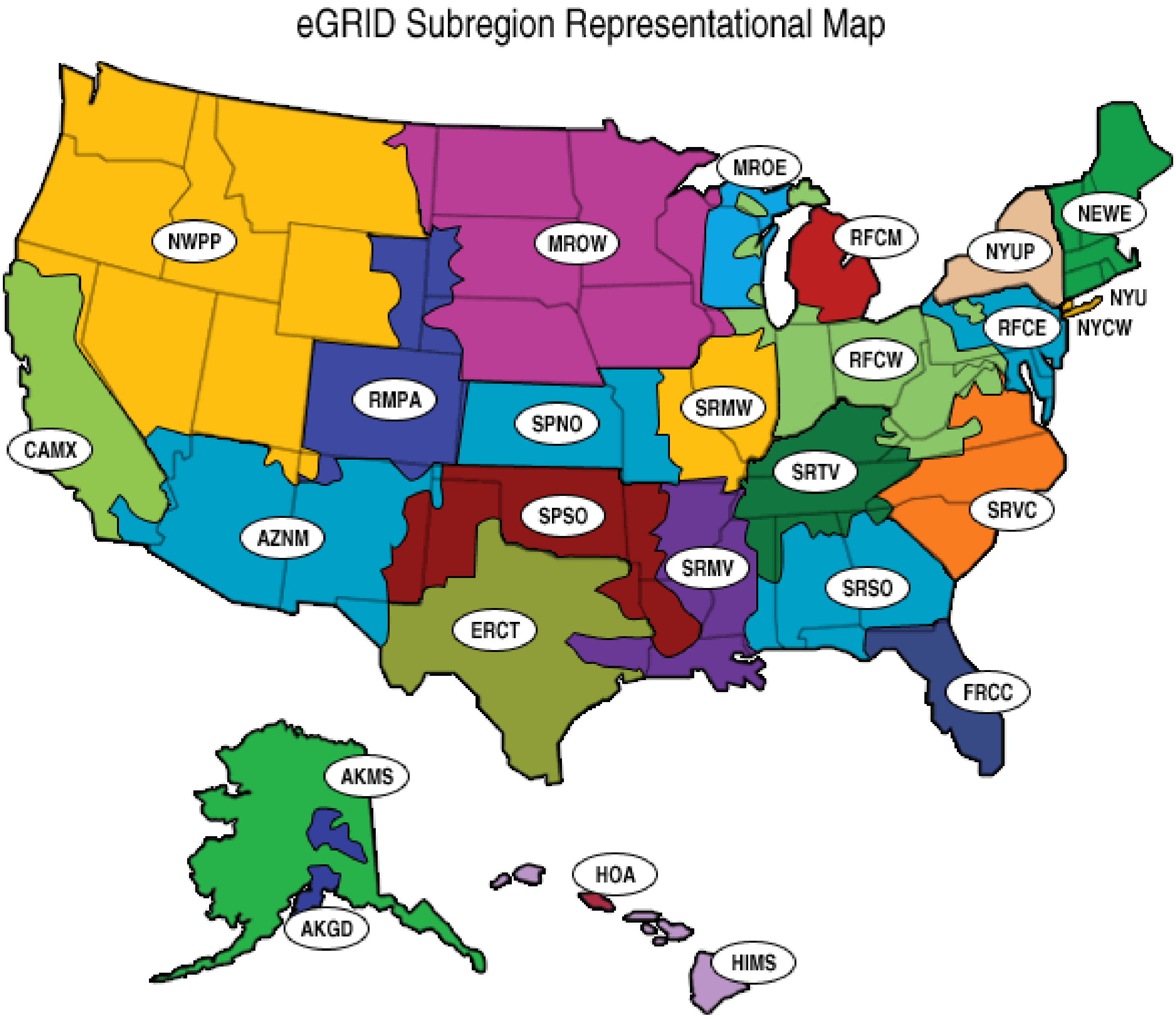


Figure A.12. : Map of eGrid Subregions

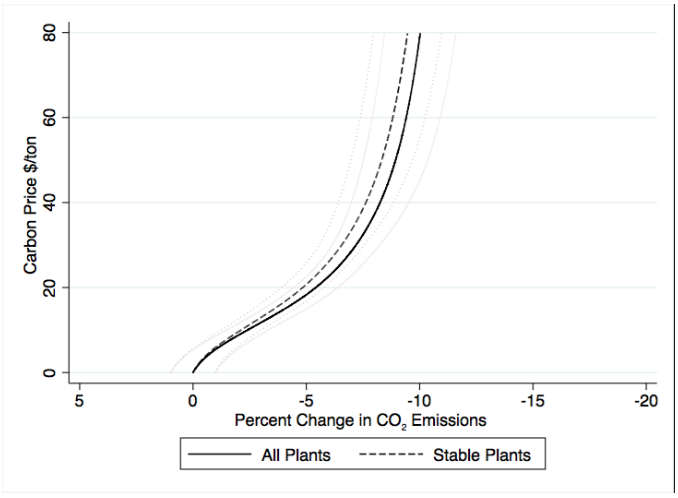
but differences are not as pronounced. In the West, however, controlling for non-fossil generation is particularly important due to the large share of hydro capacity in the region.

We also explore the sensitivity of the results to various time fixed effects as well as sub-samples of the data in Table A.6. The first column includes all the controls in the main specification, but no season-of-sample fixed effects. The subsequent columns add progressively finer, time-based fixed effects up to month-of-sample fixed effects. The final two columns split the sample into the first and second half of the sample. Including fixed effects in for a time trend is important for the results. Adding year fixed effects, which would control for trends in the types of generating capacity on the grid, reduces the estimated impact in each region. Controlling additionally for seasonality, with season-of-sample fixed effects, increases the predicted effect of a $20 carbon price, though not dramatically. However, using month-of-sample fixed effects absorbs much of the variation in prices necessary to identify the effect. Month-of-sample fixed effects greatly reduce the estimated impact of a carbon price in all interconnections and render it statistically insignificant in ERCOT and the West.

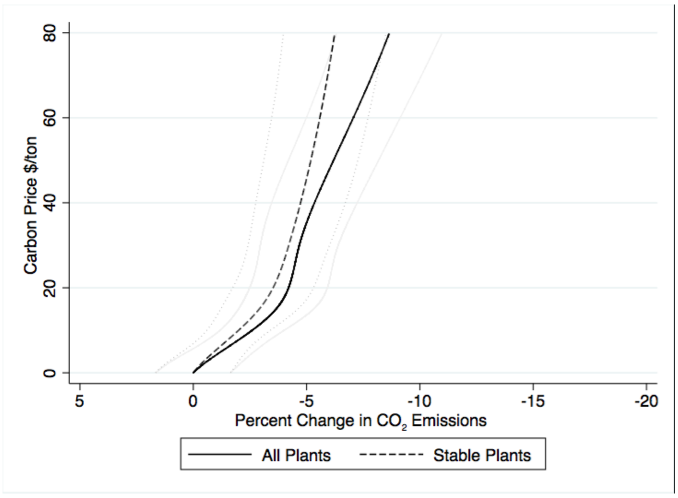
Table A.5—: Robustness to Controls

	CO$_2$ Change at $20/ton					
	(1)	(2)	(3)	(4)	(5)	(6, Main)
East	-24.3***	-7.86***	-6.67***	-5.85***	-5.64***	-5.54***
	(1.35)	(0.46)	(0.45)	(0.46)	(0.50)	(0.50)
ERCOT	-23.1***	-4.61***	-4.22***	-3.92***	-3.92***	-3.96***
	(2.31)	(1.08)	(1.22)	(1.02)	(1.02)	(1.00)
West	-7.79***	1.08	0.98	-2.59**	-2.15	-2.05
	(1.24)	(0.99)	(1.20)	(1.10)	(1.14)	(1.14)
Load	No	**Yes**	Yes	Yes	Yes	Yes
Temperature	No	No	**Yes**	Yes	Yes	Yes
Non-fossil	No	No	No	**Yes**	Yes	Yes
Imports	No	No	No	No	**Yes**	Yes
SO_2 Prices	No	No	No	No	No	**Yes**
Time F.E.	Season	Season	Season	Season	Season	Season
Obs	2557	2557	2557	2557	2557	2557

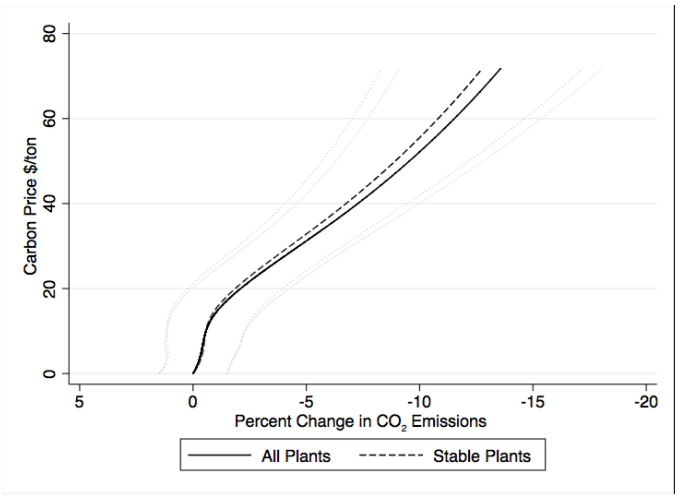
Standard errors shown in parentheses.



(a) Eastern Interconnection



(b) ERCOT Interconnection



(c) Western Interconnection

Figure A.13. : Stable Plants' Response to Carbon Price by Interconnection

Table A.6—: Robustness to Time Effects

	CO_2 Change at \$20/ton					
	(1)	(2)	(3, Main)	(4)	(5)	(6)
East	-5.64***	-4.16***	-5.54***	-2.87***	-4.22***	-4.54***
	(0.59)	(0.57)	(0.50)	(0.30)	(0.90)	(0.63)
ERCOT	-5.51***	-3.00***	-3.96***	-0.07	-2.75	-5.47***
	(0.82)	(0.97)	(1.00)	(1.04)	(1.54)	(1.10)
West	-4.29***	-1.45	-2.05	-0.24	-4.49**	-2.30**
	(0.82)	(0.91)	(1.14)	(0.99)	(1.80)	(1.01)
Load	Yes	Yes	Yes	Yes	Yes	Yes
Temperature	Yes	Yes	Yes	Yes	Yes	Yes
Non-fossil	Yes	Yes	Yes	N/A	Yes	Yes
Imports	Yes	Yes	Yes	N/A	Yes	Yes
SO_2 Prices	Yes	Yes	Yes	N/A	Yes	Yes
Time F.E.	No	**Year**	**Season**	**Month**	**Season**	Season
Sample	Full	Full	Full	Full	**2006-2009**	**2009-2012**
Obs	2557	2557	2557	2557	1278	1279

Standard errors shown in parentheses.

A11. Carbon Price Effect on Natural Gas Prices

Table A.7 shows the average tested efficiencies (heat rates) of gas combined cycle and coal plants (EIA 2012). These averages are likely to be a conservative characterization of the relative efficiencies of natural gas and coal power plants that comprise fuel switchers; in practice the most efficient gas plants will tend to substitute for the least efficient coal plants all else equal. However, using average efficiencies will give us a general idea of the potential change in natural gas demanded due to fuel switching.

Table A.7—: Average Generator Efficiency

	Heat Rate *(mmBTU/MWh)*	Fuel CO_2 *(lbs/mmBTU)*	CO_2 Rate *(tons/MWh)*
Coal	10.11	211	1.07
Gas	7.62	117	0.45

*

REFERENCES

EIA. 2012. “Annual Energy Outlook 2012.” U.S. Energy Information Administration.