CEEPR Center for Energy and Environmental Policy Research

CO_2 Abatement in the UK Power Sector: Evidence from the EU ETS Trial Period

by
Meghan McGuinness and A. Denny Ellerman

08-010 September 2008

A Joint Center of the Department of Economics,
MIT Energy Initiative, and Sloan School of Management

CO_2 Abatement in the UK Power Sector:

Evidence from the EU ETS Trial Period

Meghan McGuinness and A. Denny Ellerman[1]

Massachusetts Institute of Technology

Abstract

This paper provides an empirical assessment of CO_2 emissions abatement in the UK power sector during the trial period of the EU ETS. Using an econometrically estimated model of fuel switching, it separates the impacts of changes in relative fuel prices and changes in the EUA price on the utilization and emissions of coal and natural gas-fired generating units. We find clear statistical evidence that the CO_2 price did impact dispatch decisions, resulting in natural gas utilization that was from 19% to 24% higher and coal utilization that was 16% to 18% lower than would have otherwise occurred in 2005 and 2006. Abatement as a result of fuel switching in the power sector is estimated to have been between 13 million and 21 million tons of CO_2 in 2005 and 14 and 21 million tons in 2006.

1. Introduction

There can be no doubt that the first phase of the European Union's CO_2 Emissions Trading Scheme (EU ETS) resulted in a significant price on carbon in 2005 and 2006; however, evidence of behavioral changes in response to this price has been limited and largely anecdotal (Convery, De Perthuis, and Ellerman 2008). Skeptics of the EU ETS could also point to the increase in coal fired generation in the United Kingdom (UK) and the concomitant decrease in gas-fired combined cycle gas turbine (CCGT) generation, when compared with earlier years, as evidence that the program has had little effect. The evolution of generation shares in the UK is particularly interesting since the UK has the most liberalized electricity market in Europe, where the EU allowance (EUA) price would be expected to have the greatest effect on operator behavior.

---

[1] McGuinness (mcguinne@mit.edu) received her masters degree from the Technology and Policy Program and Ellerman (ellerman@mit.edu) is a Senior Lecturer with Sloan School of Management. Financial support from the Doris Duke Charitable Foundation for the research underlying this paper is gratefully acknowledged. We are also indebted to Andrew Sweeting and Tom Stoker for helpful advice.

Previous research has provided ex ante and simulation estimates of abatement in the UK power sector in response to a CO_2 price. In a study done prior to the start of the EU ETS, ILEX Energy Consulting (2003) projected average annual abatement of 13 to 15 million tons under a high gas price and high carbon price scenario that comes closest to matching observed data for 2005 and 2006 (though the assumed average annual prices for both are lower than observed). Another estimate is available from Delarue, Ellerman, and D'haeseleer (2008), who employed a simulation model of the European power system using actual zonal demand and actual fuel and EUA prices in 2005 and 2006. In the model version that was calibrated to mimic pre-ETS demand and zonal generation shares, they estimated abatement from fuel switching in the UK of about 16 million tons in 2005 and 8 million tons in 2006.

This paper provides the first empirical verification of CO_2 abatement in the UK power sector. Panel regression techniques are used to estimate a reduced form model of coal and CCGT plant utilization in the UK power sector based on plant utilization, aggregate demand, and fuel and CO_2 costs during the trial phase (2005-06) of the EU ETS. Running the model without the CO_2 cost component provides an estimate of what coal and CCGT plant utilization would have been in the absence of the EU ETS. The difference in utilization multiplied by available capacity and the observed emission rate at each plant provides the estimate of abatement due to the CO_2 price.

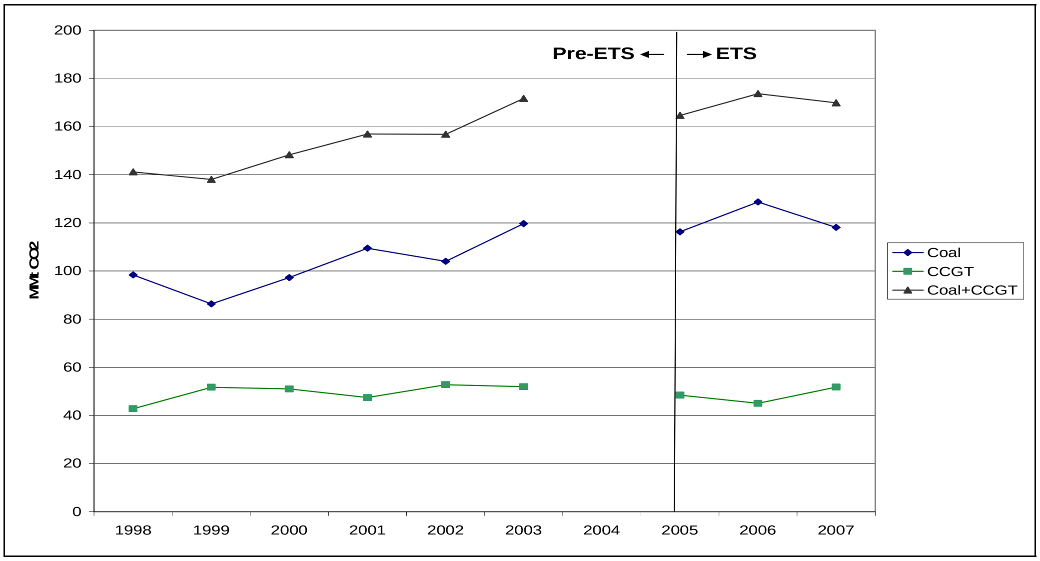
The paper proceeds as follows. Section 2 provides an overview of emission and generation trends in the UK power sector. Section 3 presents an overview of the data used in specifying the econometric model. Section 4 describes the two specifications used to estimate the relationship of plant utilization to variables reflecting aggregate demand and the variable cost of generation. Section 5 presents econometric results, and section 6 presents the generation, emissions, and abatement estimates derived from these results. Finally, section 7 concludes.

2. **Overview of Trends in the UK Power Sector**

Figure 1 presents annual emissions from UK coal and CCGT plants over the years 1998-2007.[2]

[2] Year 2004 is omitted because emissions data are only rarely reported in the Phase II NAP. While 2004 emissions data are available from the European Pollutant Emissions Registry (EPER), they are not included because of the disparity between plant-level EPER data and NAP or CITL data for other years.

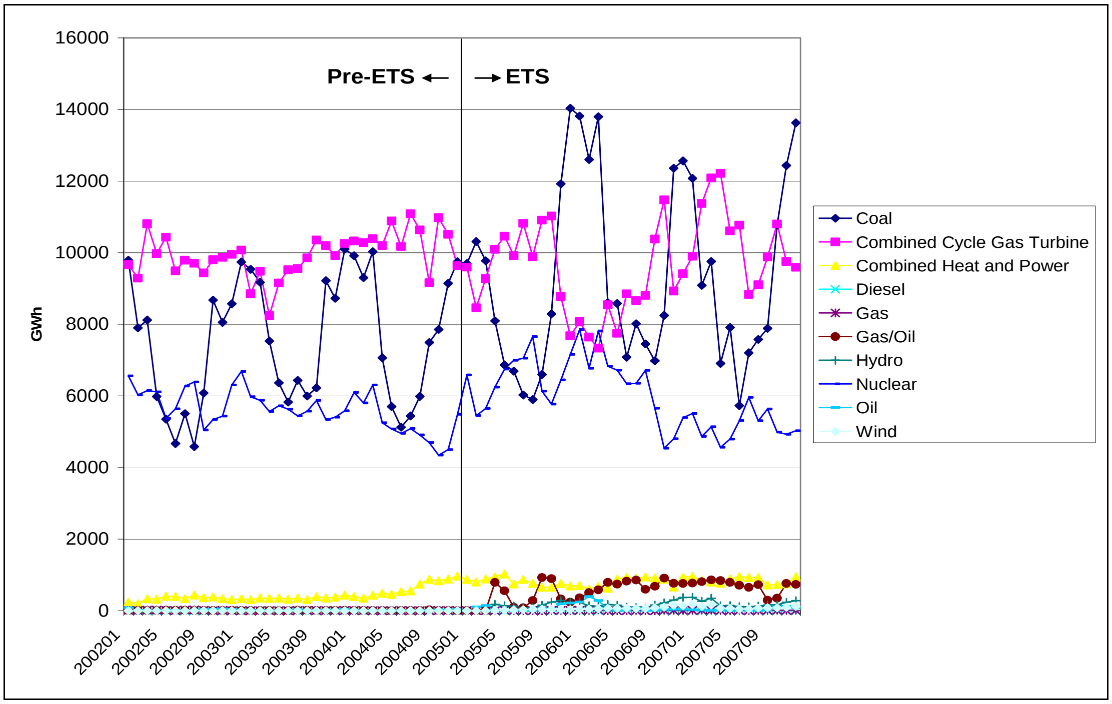
Figure 1. Annual Emissions from UK Coal and CCGT Plants, 1998-2007



Source: UK NAP I and CITL

The overall upward trend in emissions is driven by an increasing reliance on fossil-fuel-fired power plants, and especially coal-fired plants for which utilization and generation has increased while that of CCGT plants has remained largely constant. Another important feature of the UK power sector is revealed by the monthly generation data, which are shown in Figure 2 below.

Figure 2. Monthly Generation by Plant Type, 2002-2007



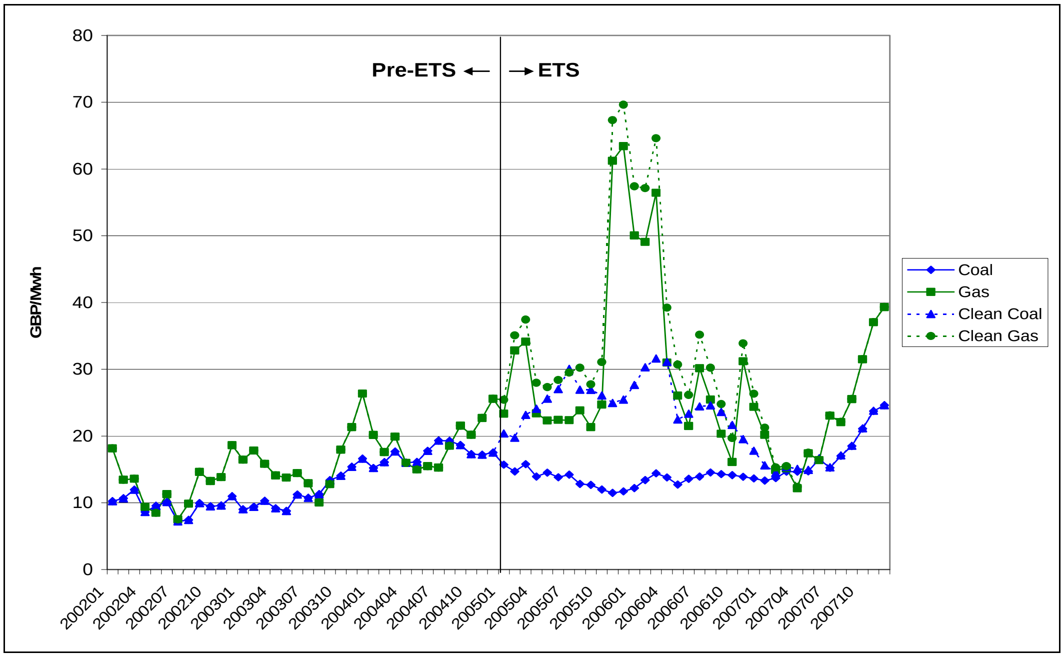
Source: EnAppSys, Ltd.

The pronounced seasonal variations in the UK load are met, not by CCGT plants as in most countries, but by coal-fired plants. Furthermore, prior to late 2005, the UK CCGT units operated as the primary base load plants, with fairly steady generation of around 10 terawatt-hours (TWh), while coal plants cycled between 6 TWh of aggregate generation in the summer to winter peaks of as much as 10 TWh. Then in late 2005, CCGT generation fell precipitously to a level roughly 20% below the pre-2005 level and stayed there for almost a year. Coal-fired units made up the difference and since then they have experienced winter peaks and summer troughs that are generally higher than in the pre-2005 period.

A number of explanations exist for this pattern. First, many CCGT plants were owned by independent power producers who have had long term take-or-pay gas supply contracts with relatively high minimum take provisions. However, during periods of high gas prices, such as occurred during the trial phase of the EU ETS, some contracts allow plant owners to sell gas on the spot market rather than use it for electricity production (UK Competition Commission 2001). Also, other contracts were increasingly being modified to allow such sales (ILEX Energy Consulting 2003). Second, many older coal plants in the UK have not been maintained sufficiently to serve as base load plants. Further, coal plant operation has been somewhat restricted under the UK's environmental regulations that place a bubble on SO_2 emissions at individual plants. However, as gas prices have increased and coal plants become increasingly economic, some plants have succeeded in extending operating hours by switching to low sulfur coal, and others have installed or are planning to install flue gas desulfurization. (Power UK 2006).

The impact of the EU ETS on fuel switching depends upon the relative cost of generating electricity using either coal or natural gas including the EUA price. The average monthly costs of coal and gas generation are presented in Figure 3. The 'clean' coal and gas costs represent the average including the cost of EUAs.

Figure 3. Monthly Average Cost of Generation for Coal and Gas, 2002-2007



Source: Bloomberg, Powernext

Prior to 2005, the average costs of generating electricity from coal and natural gas were relatively close, but from 2005 on a significant separation developed to the disadvantage of gas-fired electricity except for a brief period of early 2007. As indicated by the 'clean' costs in Figure 3, the inclusion of a carbon price in 2005 had a much greater effect on the cost of coal-fired generation than on that of natural gas. Nevertheless, for considerable periods of time, and especially in late 2005 and early 2006, the relatively high carbon prices were not enough to compensate for the still greater increases in natural gas prices. This change in the price of natural gas relative to that of coal largely explains the increase in coal-fired generation in the UK in 2005 and 2006 notwithstanding a significant carbon price.

3. Overview of Data

While metered generation data for individual power plants are proprietary in the UK, individual unit notification data can be purchased from EnAppSys, Ltd., which provides data management services for the UK wholesale electricity market. Available data include information on individual units' planned generation and availability. Final physical notification (FPN) represents a generating unit's intended generation for a particular block of time as notified to the grid operator. In practice, this generation may be adjusted in response to instructions from grid operators through the grid's balancing mechanism. The result of these instructions is provided in the bid-offer acceptance (BOA) volume. The sum of an individual unit's FPN and BOA volume represents the best estimate of a plant's output absent actual metered generation data. Unit-level availability for a particular settlement period is given by its maximum export limit

(MEL), or the maximum amount of power that an individual unit can export to the grid at that time. A unit's MEL represents short-term availability considering mechanical conditions and weather.[3] The sum of FPN and BOA divided by MEL provides an estimate of a unit's utilization rate over a given settlement period. Monthly generating unit-level data on plant type, FPN, BOA volume, and MEL were obtained for the years 2002-2007, and aggregated to the plant level.[4]

Plant level output data were supplemented with additional information on emissions, demand, fuel prices, and EUA prices. Annual emissions data at the plant level were obtained from the UK Phase I National Allocation Plan for the years 2002-2003 and the Community Independent Transaction Log for the EU ETS trial period years of 2005-2007.[5] These data were used to determine annual average emission rates both at the plant level and for all CCGT and coal plants. Monthly power sector load data were obtained from National Grid.[6] Monthly average coal prices were calculated using the API #2 month ahead coal price (McCloskey index for coal), and average gas prices from the NBP UK day ahead gas price.[7] Finally, monthly average EUA prices were calculated from Powernext CO_2.

The sample was limited to coal and CCGT plants since switching between these two technologies is expected to be the primary source of CO_2 emission reductions in the power sector. In addition, data used in the regressions was limited to the years 2005-2007 for two reasons. First, the absence of plant-level emissions data for the year 2004 makes it difficult to evaluate emissions for this year. Second, preliminary regressions during this research suggested that utilization in the years 2002 and 2003 was less sensitive to changes in relative fuel prices than in 2004 and beyond. Restricting the sample to 2005-07 data avoided the possibility that omitted factors that were present in these earlier years but not later might bias the estimates of utilization during the trial period. The high variability of EUA prices during 2005-07 provides sufficient identification of the effect of the CO_2 price on utilization. Thus, the final sample used to estimate abatement consisted of an unbalanced panel of 29 CCGT and 16 coal plants and a total of 1572 monthly observations.

---

[3] Because MEL can be adjusted after notification, but FPN cannot, in the event of plant failure MEL is reduced but FPN is not, resulting in a situation where FPN can be greater than MEL. Observations where FPN/MEL was greater than 2 were assumed to be either clear evidence of plant failures or data errors, and were dropped from the data set.

[4] Additional information on this data is available at http://www.bmreports.com/bwx_help.htm#reportGuide.

[5] UK NAP I data is available at http://www.defra.gov.uk/environment/climatechange/trading/eu/operators/phase-1.htm; CITL data is available at http://ec.europa.eu/environment/ets/.

[6] Data are available at http://www.nationalgrid.com/uk/Electricity/Data/Demand+Data/.

[7] These were converted into costs per MWh by using monthly fuel use data from BERR (2008) and FPN data.

4. Model Specification

The impact of the EU ETS allowance price on CCGT and coal plant utilization was estimated using two specifications, which vary only by the representation of the EU ETS price in the equation. Both specifications relate the utilization rate of plant *i* in month *t* to explanatory variables associated with demand, fuel price, and the EUA price. These reduced form models are not intended to provide a comprehensive model of CCGT and coal plant behavior within the power sector. Rather, they are intended to provide an estimate of the response of coal and CCGT plants to changes in variable generation costs that include fuel and CO_2 prices. Linear specification is used to relate explanatory variables to unit utilization, allowing for a simple multiplicative calculation of emission estimates.

The first specification, below, considers the EUA price in absolute terms (€/metric ton) separate from the relative fuel prices of coal and gas expressed as the relative cost of generation (£/MWh):

$$\begin{aligned} FPNBOAMEL_{it} &= Demand_t + Coal * Demand_t + NukeFPN_t + Fuelratio_t \\ &+ Coal * Fuelratio_t + EUAprice_t + Coal_t * EUAprice + u_i + \varepsilon_{it} \end{aligned} \qquad (1)$$

Where

FPNBOAMEL = A measure of an individual plant's monthly average utilization rate, calculated as an individual plants monthly aggregate FPN, adjusted by the BOA volume, divided by the plant's monthly aggregate stated MEL.

Coal = A dummy variable, equal to 1 if a plant is coal fired, and 0 if a plant is a CCGT, that is included to differentiate the effects of specific variables on coal and CCGT plants.

Demand = Monthly aggregate demand for electricity in the UK, in MWh.

NukeFPN = The aggregate monthly stated final physical notification of nuclear plants, in MWh.

Fuelratio = The average per MWh price of coal divided by the average per MWh price of gas. These values are calculated using the average monthly fuel use per MWh by each plant type.

EUAprice = The monthly average price for EU ETS allowances in Euros.

u_i = plant-specific fixed-effect

The inclusion of plant-specific effects enables consideration of time invariant characteristics of individual plants that may impact utilization. These may include factors such as size, configuration, efficiency, location, and fuel contracting arrangements.

Specification 2 is the same as specification 1 with the exception of how the fuel and EUA prices are represented. A clean cost ratio for coal/gas was calculated, which is composed of the per MWh cost of generation for coal and natural gas including both fuel and EUA prices. In specification 2, this clean price ratio is broken into its component parts to reflect the separate effects of the fuel and the EUA prices. Specification 2 is therefore as follows:

$$\begin{aligned} FPNBOAMEL_{it} &= Demand_t + Coal^{*}Demand_t + NukeFPN_t + FuelratioC_t \\ &+ Coal^{*}FuelratioC_t + ETSadd_t + Coal^{*}ETSadd_t + u_i + \varepsilon_{it} \end{aligned} \quad (2)$$

Where

FuelratioC = The fuel cost component of the clean cost ratio[8],

ETSadd = The EUA component of the clean fuel price ratio, and all other variables are as described under specification 1.

4.1 Overview of the relationship between explanatory variables and plant utilization

Specifications 1 and 2 contain variables related to demand and the marginal cost of generation. Since coal plants are clearly relied upon to meet increased load during winter as shown in Figure 2, and CCGT much less so, coal utilization would be expected to be positively related to increases in demand, and CCGT utilization slightly negative, if at all.[9] The aggregate FPN from nuclear units is included because nuclear availability has declined somewhat over the last few years and both CCGT and coal plants would likely have been called upon to meet the additional load. No differentiation is made between the effect on coal and gas plants on the premise that the observable gradual (and non-seasonal) decline in nuclear generation has an equal effect on both types of replacement fossil generation.

With respect to fuel and EUA prices, as the per MWh cost of coal generation increases relative to that of gas, utilization would be expected to fall at coal plants and increase at gas plants. Similarly, because an increase in the EUA price will result in a larger increase in the marginal cost of generation for coal than for CCGT plants, an increase in the EUA price should lead to a reduction in coal plant utilization and increase in CCGT utilization if all other factors remain unchanged.

---

[8] Decomposition of the clean cost ratio, $\frac{fuel\cos t_{coal} + CO2\cos t_{coal}}{fuel\cos t_{gas} + CO2\cos t_{gas}}$, is such that the fuel cost component will equal *Fuelratio* in specification 1 only when the EUA price is zero.

[9] There has been an increasing tendency for CCGT generation to decline during the winter peaks since 2004.

5. Results

The results of specification 1 are presented in table 1. The coefficients represent the impact of the relevant variables on a unit's utilization rate.

Table 1. Estimated Coefficients of Specification 1

Variable	Coefficient	Std. Dev.	T-Stat.
Demand	-2.18E-09	1.15E-09	-1.89
Coal*Demand	8.61E-09	1.90E-09	4.54
NukeFPN	-3.53E-08	7.33E-09	-4.81
FuelRatio	0.5037	0.0371	13.58
Coal*FuelRatio	-1.1278	0.0601	-18.76
EUAprice	0.0082	0.0008	9.70
Coal*EUAprice	-0.0169	0.0012	-14.03

Number of obs =	1572
F(7,1520) =	112.15
Prob > F =	0
R^2 =	0.3406

The results from specification 1 indicate that all factors included in the regression impact utilization of coal-fired plants in the expected direction and that their effect is statistically significant at the 5% level or better. The same holds true for CCGT units, with the exception of demand, which is not significant at the 5% level. Aggregate demand is negatively associated with utilization at CCGT plants and positively associated with utilization of coal plants. An increase in nuclear output has a slight negative effect on coal and gas plant utilization, which is consistent with the expectation that is nuclear plant availability decreases, this load will be picked up by fossil fuel-fired plants. An increase in the EU ETS allowance price of 1 Euro leads to an increase in utilization of about 0.8 percentage point across CCGT plants, and a reduction in utilization of about 0.9 across coal plants. Finally, this specification suggests a strong sensitivity to the relative price of coal and gas. An increase of 0.1 in the ratio of the relative cost of coal to gas is associated with a five percentage point increase in utilization across gas plants and a six percentage point reduction in utilization across coal plants.

The absolute value of the change in utilization for coal-fired plants is greater than that of CCGT plants for both fuel and CO_2 costs. This suggests that other forms of generation, besides CCGT plants, probably nuclear generation, benefit from increases in the cost of coal generation. During 2005-07, average annual generation from coal-fired and CCGT plants was approximately equal (133-134 TWh), but gas plant utilization was consistently higher than that of coal plants (89% to 93% vs. 75% to 81%). If changes in the utilization of coal-fired plants were compensated only by CCGT plants, the CCGT coefficients for both fuel and CO_2 costs would need to be greater in absolute value than the coal coefficients, since CCGT capacity is less than coal-fired capacity.

The results of specification 2 are presented in Table 2. These results are generally consistent with those of specification 1.

Table 2. Estimated Coefficients of Specification 2

Variable	Coefficient	Std. Dev.	T-Stat.
Demand	-2.31E-11	1.22E-09	-0.02
Coal*Demand	3.51E-09	2.03E-09	1.73
NukeFPN	-2.96E-08	6.40E-09	-4.62
FuelRatioC	0.4333	0.0351	12.33
Coal*FuelRatioC	-0.9851	0.0493	-18.68
ETSadd	0.4969	0.0413	12.03
Coal*ETSadd	-1.1239	0.0671	-16.76

Number of obs =	1572
F(7,1520) =	115.31
Prob > F =	0
R^2 =	0.3468

The coefficients for the impact of the relative fuel cost component indicate that an increase of 0.1 in the relative fuel cost component of the clean cost ratio results in an increase in CCGT utilization of about approximately 4.3 percentage points, and a decrease in coal plant utilization of 5.5 percentage points across the sector. An increase of 0.1 in the EUA component of the clean fuel price ratio results in an increase in utilization of approximately 5.0 percentage points among gas plants and a decrease in utilization of approximately 6.3 percentage points across coal plants.[10] As in specification 1, the response of coal plant utilization is greater than that for CCGT plants for both fuel and CO_2 costs.

A further interesting feature of specification 2 is the apparent inequality of the effects of changes in fuel and CO_2 costs, which are expressed equivalently in this specification. If both relative fuel cost and the EUA cost were given equal weight in plant bidding decisions, the coal and gas coefficients for *Fuel Ratio* and *ETSadd* would be equal. However, the coefficients for *ETSadd*, representing CO_2 cost components, are slightly higher in absolute value than those for *Fuel Ratio*, representing fuel cost. The standard test for the equality of these coefficients is rejected at the 1% level for the coal coefficients, but only weakly, at the 10% level, for the CCGT coefficients. These results suggest that, at least for coal plants, changes in the CO_2 cost of generation have a greater effect on plant utilization than equivalent changes in fuel cost.

Finally, under specification 2, aggregate demand is not a significant factor in determining utilization of either CCGT plants or coal plants. As is the case in specification 1, nuclear plant output has a small negative effect on coal and CCGT plant utilization.

6. Generation and Abatement Estimates

Using the specifications above, monthly predicted utilization was calculated for each individual plant by substituting the estimated coefficients and plant level fixed effects, into equations 1 and 2 for each observation. Monthly counterfactual utilization was calculated in the same manner, only substituting zero for the EUA price in specification 1, and for the EUA component of the clean price ratio in specification 2. These predicted utilization rates were multiplied by the monthly MEL for each plant and

[10] As was the case for the fuel cost component, an equality test yielded borderline results (Prob >0.0620).

each plant's annual average emission rates, assuming that these two variables would equal their observed values in the counterfactual.[11] Tables 3 and 4 display observed, predicted, and counterfactual generation (as captured by the sum of FPN plus the BOA volume) by plant type for specifications 1 and 2, respectively.

Table 3. Observed, Predicted, and Predicted Counterfactual Generation (MWh), Specification 1

Year	Plant Type	Observed FPN+BOA	Predicted EU ETS FPN+BOA	Percent Difference from Observed	Predicted Counterfactual FPN+BOA	Percent Difference due to EUA Price
2005	Coal	123,295,903	128,872,629	4.5%	155,668,876	(17%)
	CCGT	108,941,783	105,334,872	(3.3%)	84,943,173	24%
2006	Coal	140,850,705	138,936,354	(1.4%)	167,694,342	(17%)
	CCGT	97,605,135	99,917,248	2.4%	80,580,587	24%
2007	Coal	129,863,227	127,877,587	(1.5%)	129,014,674	(0.9%)
	CCGT	116,099,954	118,377,374	2.0%	117,546,190	0.7%

Table 4. Observed, Predicted, and Predicted Counterfactual Generation (MWh), Specification 2

Year	Plant Type	Observed FPN+BOA	Predicted EU ETS FPN+BOA	Percent Difference from Observed	Predicted Counterfactual FPN+BOA	Percent Difference due to EUA Price
2005	Coal	123,295,903	127,243,421	3.2%	155,007,692	(18%)
	CCGT	108,941,783	106,417,771	(2.3%)	88,076,838	21%
2006	Coal	140,850,705	139,342,888	(1.1%)	165,883,834	(16%)
	CCGT	97,605,135	99,444,349	1.9%	83,903,877	19%
2007	Coal	129,863,227	128,848,167	(0.8%)	130,627,064	(1.4%)
	CCGT	116,099,954	117,919,427	1.6%	116,814,780	1.0%

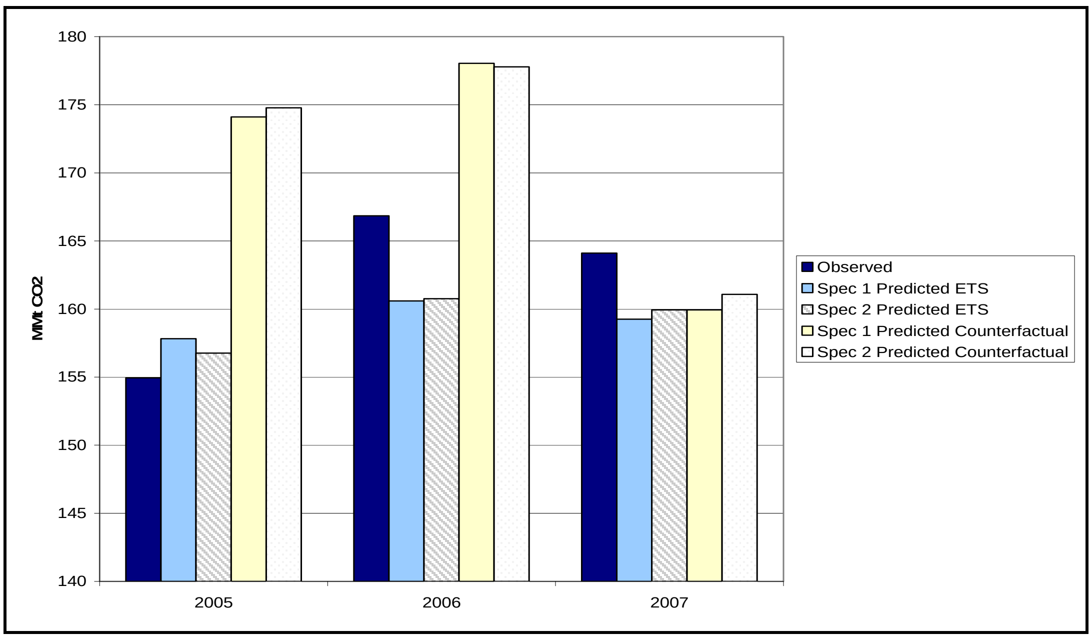
[11] Assuming that MEL would remain constant in the counterfactual would imply that the timing of plant or unit shutdowns for maintenance would not be affected by the EU ETS. Assuming plant emissions rates (in tons per MWh) in the counterfactual are the same as those observed with the EUA price would lead to a slight underestimate of abatement to the extent that facilities are able to improve generation efficiency (MWH per mmBtu) in response to a CO_2 price.

As tables 3 and 4 suggest, both specifications provide predictions of generation by fuel type that are close to observed values. Both specifications overestimate coal generation in 2005, while underestimating CCGT generation, and slightly overestimate CCGT generation (by 1-2%) in 2006 and 2007, while underestimating coal.[12]

More importantly, both specifications indicate that the EUA price had the effect of reducing coal generation by 16% to 18% in years 2005 and 2006 and increasing CCGT generation by 19% to 24%. Thus, while coal generation increased under the EU ETS in 2005 and 2006, as a result of high gas prices, the counterfactual suggests that these increases would have been substantially larger absent the EU ETS.

The predicted ETS and counterfactual generation numbers presented above were used to calculate predicted and counterfactual emissions, using annual average emission rates for each plant. Figure 4 presents observed emissions and predicted emissions for both the ETS and counterfactual cases using specifications 1 and 2. Both specifications slightly overestimate emissions in 2005 and slightly underestimate emissions in 2006 and 2007, in accordance with their overestimation of coal generation in 2005 and underestimation in the following two years. Since these errors could be expected to be replicated in both predictions, they should not affect the estimate of abatement.

Figure 4. Observed, Predicted ETS, and Predicted Counterfactual Emissions, Specifications 1 and 2



Note: Scale begins at 140 MMt CO_2, magnifying the differences between observed and predicted emissions.

[12] Total CCGT and coal plant generation is about 3-4% greater in 2005 and 2006 under the counterfactual than under the predicted ETS. This may reflect a reduction in electricity demand as a result of higher electricity prices, or additional shifting of generation from coal plants to generation sources other than CCGT. We do not attempt to resolve this question.

The difference between the predicted ETS and counterfactual emissions provides an estimate of the abatement that has occurred as a result of switching from coal to CCGT generation due to the EUA price. Using standard statistical techniques, it is possible to develop a confidence interval around these estimates of abatement.[13] Abatement estimates with 95% confidence intervals for specifications 1 and 2 are presented in Tables 5 and 6.

Table 5. Estimated abatement and 95% Confidence Interval, Specification 1 (tons of CO_2)

	Estimated Abatement	Min	Max
2005	16,283,047	13,164,569	19,401,524
2006	17,443,888	14,186,694	20,701,081
2007	678,596	(2,200,414)	3,557,606

Table 6. Estimated abatement and 95% Confidence Interval, Specification 2 (tons of CO_2)

	Estimated Abatement	Min	Max
2005	18,007,296	14,808,847	21,205,746
2006	17,022,066	13,735,100	20,309,031
2007	1,138,599	(2,115,616)	4,392,813

The estimates based on the two specifications provide clear evidence of abatement through fuel switching in 2005 and 2006. Taken together, they suggest that in 2005 between 13.2 and 21.2 million tons of CO_2 were abated as a result of load shifting from coal to CCGT plants and that between 13.7 and 20.7 million tons of CO_2 were similarly abated in 2006. These estimates represent roughly 8-12% of the counterfactual in both years. Under both specifications the confidence interval for 2007 includes zero, meaning that the possibility of no abatement cannot be excluded in this year. Given the near-zero CO_2 price for most of 2007, such a result is not surprising.

These abatement estimates provide the first rigorous empirical verification of abatement in response to a CO_2 price in Europe. Previous research using predictive or simulation models have suggested that such abatement would or had occurred. In a study done prior to the start of the EU ETS, ILEX Energy Consulting (2003) projected about 13.3 million tons of abatement in 2005 and 13.9 million tons of abatement in 2006 under a high gas price and high carbon price scenario that comes closest to matching observed data in 2005 and 2006 (though the assumed average annual prices for both are lower than observed). These results also confirm the finding of abatement in Delarue, Ellerman, and D'haeseleer (2008) based on a simulation model of the EU power sector with observed

---

[13] See Schennach (2000). If abatement from fuel switching, a_i at plant i is related to a vector x of relevant variables by a vector x_i of coefficients b, such that $a_{i=}\ x_i'b$, then the variance of total abatement is:

$$Var\left(\sum_i a_i\right) = \left(\sum_i x_i'\right) Var(b) \left(\sum_i x_i\right)$$

price and demand. In the model version that was calibrated to actual demand in 2003 and 2004, they estimated abatement from fuel switching in the UK of about 16 million tons in 2005 and 8 million tons in 2006. While their 2005 estimate is quite close to the estimates presented in tables 5 and 6, their 2006 estimate is about 6 million tons below the minimum of the 95% confidence interval calculated for both specifications.

In interpreting the abatement estimates derived in this paper, it is important to consider whether the amount of coal utilization predicted in the counterfactual—about 20% more than predicted ETS generation—is reasonable, and thus whether the fuel switching would have been as substantial as the model predicts. To evaluate the counterfactual estimates, monthly FPN+BOA by plant type under the counterfactual were compared with monthly MEL by plant type, in order to determine whether the counterfactual may have over-predicted the amount of coal generation and thus the switching potential. In fact, the counterfactual does appear to overestimate coal generation somewhat during the 2005 and 2006 peak seasons. Assuming that coal plants can operate at up to 100% of MEL, and that stated coal MEL would not have been greater under the counterfactual conditions, specification 1 appears to have estimated coal generation in excess of stated availability by about 5 million MWh in 2005 and 4.8 million MWh in 2006. This would suggest a level of counterfactual coal generation on the order of 3% less than what was predicted in 2005, and about 2.8% less than what was predicted in 2006. In Specification 2, constraining coal generation to be no greater than 100% of stated MEL implies an overestimate of about 3.8 million MWh (2.5%) in 2005 and just 2.6 million MWh (1.6%) in 2006. If these corrections are appropriate, the magnitudes of the shift from coal-fired to CCGT generation in 2005 and 2006 are reduced but not eliminated. In tables 3 and 4, the reductions in coal use would be around 15%, instead of 16% to 18%, and the increase in CCGT use would be 15% to 17%, instead of 19% to 24%. The finding of abatement in response to the CO_2 price would not be changed.

7. Conclusion

This paper provides an empirical estimate of the response of the UK power sector to the CO_2 price and of the abatement that can be attributed to the EU ETS in this sector. Our estimate is based on econometric estimation using panel regression techniques of the relationship between coal and CCGT plant utilization and the variable cost of generation based on fuel and CO_2 prices. We find strong statistical evidence that the CO_2 price did impact dispatch decisions, resulting in CCGT utilization that was from 19% to 24% higher and coal utilization that was 16% to 18% lower than would have otherwise occurred in 2005 and 2006. The data reveal no statistically perceptible effects in 2007 when EUA prices were near zero for most of the year. Abatement as a result of fuel switching in the power sector is estimated to have been between about 13 million and 21 million tons of CO_2 in 2005 and 14 and 21 million tons in 2006. Allowing for the possibility that coal utilization could not have been as high as predicted in the no-ETS counterfactual at some plants, reduces these estimates by 20% at most. The observed annual increases in coal generation in the UK power sector in 2005 and 2006 were the result of significantly higher natural gas prices in those years compared with earlier years, not of any failure of the EU ETS price to have an effect. Absent the CO_2 price, coal generation and CO_2 emissions would have been even higher.

References

Convery, F., C. De Perthuis, and A.D. Ellerman. 2008. *The European Carbon Market In Action: Lessons From The First Trading Period. Interim Report.* Available online at: http://www.aprec.fr/documents/08-03-25_interim_report_en.pdf. Also available as MIT CEEPR Working Paper 08-002. March.

Delarue, E.D., A.D. Ellerman, and W.D. D'haeseleer. 2008. *Short-term CO_2 Abatement in the European Power Sector.* Available online at: http://www.aprec.fr/documents/short_term_abatement_finalwp.pdf. Also available as MIT CEEPR Working Paper 08-008. June.

ILEX Energy Consulting. 2003. *Implications of the EU ETS for the Power Sector*. Report prepared for UK DTI, DEFRA, and OFGEM. September. Online: http://www.berr.gov.uk/files/file26987.pdf.

Power UK. 2006. "Coal's Renaissance" May 24.

Schennach, S. 2000. "Effect of Title IV on SO_2 Emissions and Heat Input." Appendix in Ellerman, A.D., P.L. Joskow, R. Schmalensee, J. Montero, and E.M. Bailey, *Markets for Clean Air: The U.S. Acid Rain Program*. Cambridge University Press.

UK Competition Commission. 2001. AES and British Energy: A report on references made under section 12 of the Electricity Act 1989. CC No. 453. January.

UK Department for Business Enterprise and Regulatory Reform (BERR). 2008. *Energy Statistics: Total Energy*. Online: http://www.berr.gov.uk/energy/statistics/source/total/page18424.html.