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SHORT-TERM CO_2 ABATEMENT IN THE EUROPEAN POWER SECTOR

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(during the preparation of this paper Erik D. Delarue was a visitor at MIT's Center for Energy and Environmental Policy Research)

ABSTRACT

This paper focuses on the possibilities for short term abatement in response to a CO_2 price through fuel switching in the European power sector. The model E-Simulate is used to simulate the electricity generation in Europe as a means of both gaining insight into the process of fuel switching and estimating the abatement in the power sector during the first trading period of the European Union Emission Trading Scheme. Abatement is shown to depend not only on the price of allowances, but also and more importantly on the load level of the system and the ratio between natural gas and coal prices. Estimates of the amount of abatement through fuel switching are provided with a lower limit of 35 million metric tons in 2005 and 19 Mtons in 2006.

KEYWORDS: European Union Emission Trading Scheme; Fuel switching; Electricity generation simulation

I. INTRODUCTION

Discussion of the significant reductions in greenhouse gas (GHG) emissions that will be required to mitigate global warming rightly focuses on fundamental changes in technology and long-term investments in capital stock that would embody low- or zero-emitting technology. While this emphasis on long-term technological change is well-placed, it can have the effect of ignoring the less spectacular but still important reduction in GHG emissions that can be obtained with existing capital stock in response to prices on GHG or CO_2 emissions. In the extreme, this focus on the long-term can lead to arguments either that a short-term reduction of emissions can be obtained only through a reduction of output or that a CO_2 price is not justified until it can be demonstrated that low- or zero-emitting technology is available. It is of course possible that a price instrument would not be sufficient to induce the development of the desired technology in the desired time frame and that other non-price instruments would be required.

Issues of how to induce long-term technological change are beyond the scope of this paper, which addresses only one aspect of the response to a CO_2 price: what is the extent of short-term abatement that can be expected in response to a carbon price? In seeking to answer this question, we look to the power sector where perhaps the greatest potential for short-term abatement exists. Power plants are dispatched on at least an hourly basis in response to load and fuel prices and power plants differ significantly in their emission characteristics due both to the fuel used and the efficiency with which that fuel is combusted to generate electricity. The specific context for our analysis is the European power sector as it has responded to the price on CO_2 that has been imposed by the European Union's CO_2 Emissions Trading Scheme (EU ETS) since 2005.

The paper proceeds as follows. The next section of the paper provides a description of the model that is used to simulate the European power sector and its response to a carbon price. Such a model is required to establish a counterfactual estimate of what CO_2 emissions would have been without a carbon price. This section of the paper also conducts a calibration of the model to actual generation and emissions data for 2003 and 2004, before a carbon price was present, in order to evaluate the extent to which actual practice departs from the assumptions that are necessarily made in any model. An important aspect in any such modeling exercise is the extent to which departures from modeling assumptions affect abatement. This will be done by developing a "calibrated" counterfactual that can be used in conjunction with a "standard" counterfactual.

The third section of the paper develops the topography of short-term CO_2 abatement in the European power sector. A simple relationship between price and short-term abatement does not exist in the power sector. In broadest terms, that relationship depends on the stock of generating plants and their utilization. The capital stock is taken as given and attention is focused on how load, fuel prices, and the CO_2 price affect utilization of that capital stock and emissions.

The fourth section of the paper presents estimates of short-term abatement in the European power sector in response to the CO_2 price imposed by the EU ETS. This price varied enormously during the three years of the first trading period corresponding to the calendar years 2005 to 2007, as did the price difference between the two principal generation fuels, natural gas and coal.

In the final concluding section, we return to the issues raised at the beginning of the paper and seek to generalize from the European experience.

II. MODEL DESCRIPTION AND CALIBRATION

A. *The E-Simulate model*

The European electricity system is modeled using E-Simulate, which was developed at the University of Leuven (Voorspools, 2004). This model simulates electricity generation dispatch on an hourly basis over an annual cycle at the power plant level. The entire system is organized as a set of interconnected 'zones', each of which corresponds to a specific country or group of countries. Transfers of electricity can occur among zones subject to the pre-specified limits on interconnection capabilities. The demand for electricity is specified by zone for each hour of the year and the model solves for the least cost dispatch of generation to meet electricity demand in all zones. Thus, E-simulate operates as a linked hourly stacking model in which the stacking of available generation is determined by power plant characteristics and fuel prices, as illustrated by Figure 1. The CO_2 price is treated as an additional cost for a specific fuel that depends on the fuel's carbon content. The stacking order of the power plants in each zone will be changed and therefore, the outcome with respect to generation and emissions

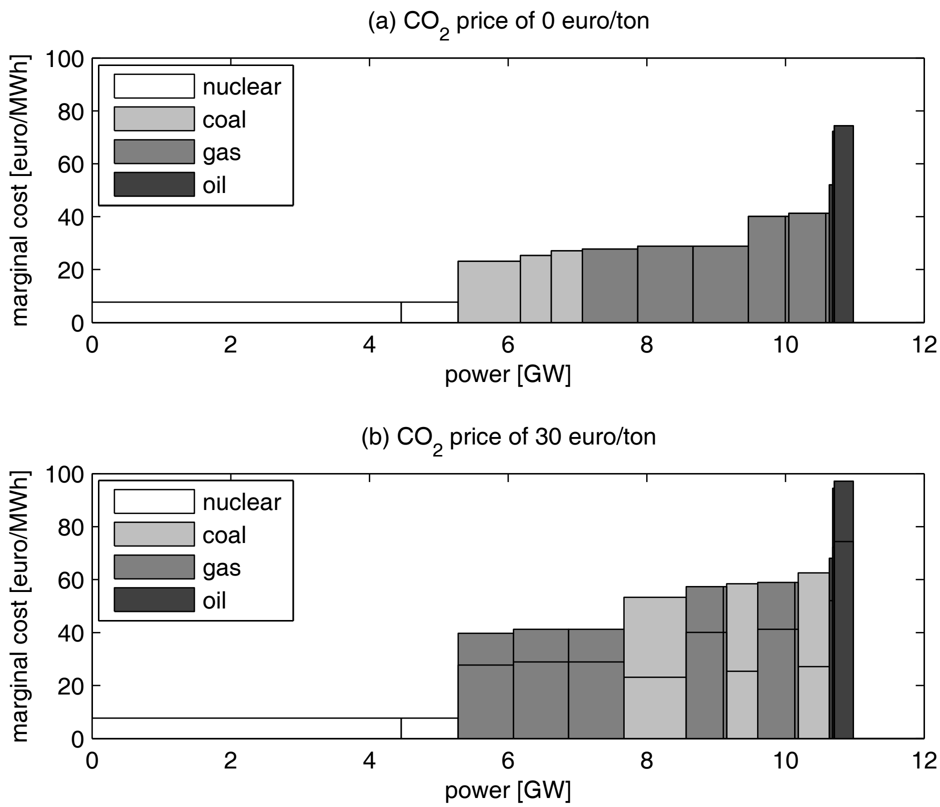

Figure 1. Stacking order in the simulation model according to marginal cost, example of the Belgian power system. (a) the stacking order in a case with no allowance cost; (b) the stacking order in a case with a 30 euro/ton cost. The part of the cost above the horizontal line in (b) reflects the CO_2 cost. Note that cogeneration units and renewables are not presented in this figure.

The input required for the model can be listed as follows:

Per zone

- **Power system**: Each zone has its own power system, consisting of all the power plants. For every power plant, the type of the power plant, the fuel used, the size (rated power output) and the efficiency at full capacity is given[1].
- **Load**: Demand for electricity for each hour of the simulated time span.

Overall

- **Technical characteristics of power plants**: Each type of power plant (e.g. combined cycle, classical steam plant, etc.) is described with several characteristics, e.g. minimum operating point (as a percentage of the rated capacity), partial load efficiencies (as a percentage of the rated efficiency), minimum up- and downtime, etc.
- **Fuel and European Union Allowances (EUA) prices**: Daily fuel and EUA prices are used.
- **Net Transfer Capacities (NTC) between zones**: Trade between zones is limited to a certain value, taken equal to the NTC.

[1] Note that power plants' rated efficiencies are power plant (country) specific.

The data sources used in this work are described in full detail in the appendix to this paper.

The output of the model consists of the electricity generation of each power plant for each hour of the simulated time span. Corresponding CO_2 emissions are made part of the output by attaching emission coefficients to plants according to fuel use and plant type.

To perform the required optimization, the model basically uses a heuristic approach. Several corrections, however, are made in the algorithm, in order to respect the technical characteristics of the power plants (minimum operating point, minimum up- and downtimes). Power plants of the same type, fuel use and efficiency are grouped together. Thus, each successive level of the zonal stacking diagrams consists of the aggregate generation available for each plant type, fuel use and efficiency.

To correctly represent the limited availability of power plants, a ‘derated’ power approach is used. This assumes that a plant has a fixed power output available, equal to its rated output multiplied by its availability factor. Thus, a 100 MW plant that is available 90% of the time is assumed to have constantly $100\ \text{MW} \cdot 0.9 = 90\ \text{MW}$ available for all hours of the year. The availability factor reflects possible forced outages. In addition, power plants also face a scheduled outage for maintenance. These outages for maintenance are typically scheduled at periods of lower demand, and are not represented in the availability factor.

Trade in electricity within and between zones is based strictly on economic incentives. Subject to the capacity constraints on interzonal transfers, neighboring zones are always potential suppliers to demand within any given zone depending on the relative cost of incremental generation within the zone and from neighboring zones. Kirchhoff’s laws are not taken into account either within zones or for flows between zones, nor are transmission constraints assumed to exist within zones.

Several specific types of power plants are dealt with prior to the optimization process in a way that their utilization is fixed at the observed values. These are cogeneration plants, which are heat-driven, and single storage hydro reservoirs and pumped storage units, both of which are used for peak shaving. Figure 2 (a) presents an overview of the model. For further details on E-Simulate, the reader is referred to Voorspools (2004) and Voorspools and D’haeseleer (2006).

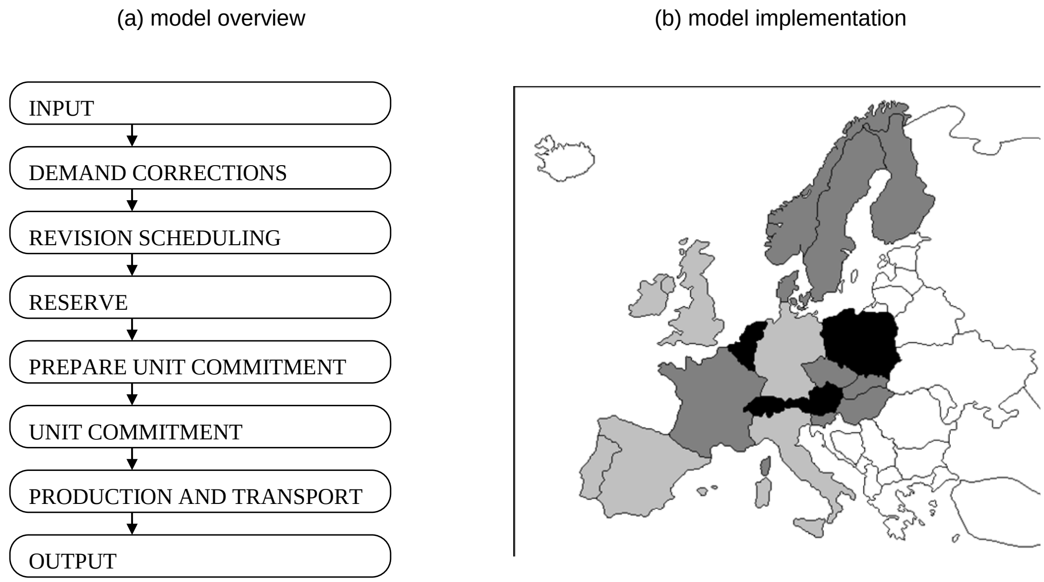

Figure 2. (a) Overview of the model's algorithm; (b) overview of the countries modeled, where adjacent countries with a similar color are grouped together in a zone.

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E-simulate models 21 European countries in a 10 zonal configuration as given in Table 1 and Figure 2 (b) and it corresponds to that used in Delarue et al. (2008). This implementation has been chosen to represent the main players adequately and to represent Europe's bottlenecks in transmission. Eight of the European Union's twenty-seven member states are not modeled: the three Baltic member states; Greece, Cyprus, and Malta because of their lack of integration with the main European grid; and Bulgaria and Romania which became member states only in 2007. Two non-EU member states, Switzerland and Norway, are included because of their close integration with neighboring EU member states in the daily operation of the European electricity grid.

Table 1 also provides a comparison of the generation and emissions of the included and excluded countries with the 19 member states that are included in E-Simulate. All the relevant countries are incorporated in the model and the included non-EU members, i.e., Switzerland and Norway, have negligible CO_2 emissions.

Table 1: Composition of the different zones considered in the model, together with historic electricity generation and CO_2 emission from electricity generation in 2004, as reported by Eurelectric (2007); values for CO_2 emissions in italics come from Eurostat (2008), reported as CO_2 emissions from 'Energy Industries', and therefore a likely overestimation of the CO_2 emissions coming from the electricity sector only.

zone		country	Electricity generation [TWh]	CO_2 emission [Mton]
1	IRL	Ireland	24.4	*15.3*
1	UK	United Kingdom	378.5	243.5
2	ES	Spain	268.7	101.8
2	PT	Portugal	44.1	21.3

3	BE	Belgium	81.4	*29.8*
3	LU	Luxembourg	4.0	*0.4*
3	NL	Netherlands	96.7	47.8
4	FR	France	548.4	*61.4*
5	IT	Italy	290.0	145.0
6	DK	Denmark	38.4	24.1
6	FI	Finland	82.2	21.5
6	NO	Norway	109.7	0.7
6	SE	Sweden	148.8	2.8
7	CZ	Czech Republic	77.9	48.0
7	HU	Hungary	33.7	18.4
7	SK	Slovakia	28.3	*12.2*
7	SL	Slovenia	13.4	*6.3*
8	PL	Poland	142.3	134.3
9	AT	Austria	62.7	12.8
9	CH	Switzerland	63.5	0.8
10	DE	Germany	577.7	279.0
-	CY	Cyprus	4.2	3.3
-	ET	Estonia	9.3	*14.9*
-	GR	Greece	54.8	53.7
-	LA	Latvia	4.4	0.8
-	LI	Lithuania	17.7	1.2
-	MA	Malta		*2.1*
-	BG	Bulgaria	37.4	21.4
-	RO	Romania	51.9	29.4

B. *Calibrating to actual conditions*

In its standard form, E-Simulate makes a number of assumptions that may be seen as unrealistic for at least some parts of the European electricity system. For instance, it assumes that the prices paid for fuels by generators and therefore used in dispatch decisions are uniform throughout the 21-country region that is modeled[2]. It also assumes

[2] Uniform in this case means 'uniform throughout Europe'. The fuel prices used are still daily prices that vary considerably over the course of the year. This assumption of uniform prices holds for coal and petroleum products, but it might be questioned for natural gas. While a price convergence between the UK and the Zeebrugge Hub (Belgium) can be demonstrated, some differences can still exist, such as between Zeebrugge and Bunde (Dutch-German border) (Neumann *et al.*, 2006). However, on a longer time frame and considering yearly data, evidence of converging prices throughout Europe can be shown (Robinson, 2007).

that wholesale markets have been completely liberalized and that perfectly competitive conditions prevail throughout. Finally, subject to ramping and other operational constraints, dispatch in every hour is unconstrained by contract considerations and all plants throughout Europe operate at standard availabilities.

While these departures from actual conditions are typical of modeling exercises and none disqualify E-Simulate from providing a realistic view of the short-term response of the European electricity system to a carbon price, a question always remains concerning the extent of the departure from actual conditions and the consequent effect on estimates of short-term abatement in response to a carbon price. Accordingly, a comparison of the standard model output against actual data for the years 2003 and 2004, before there was a carbon price, is undertaken. Based on this comparison, a “calibrated” model is developed in which the departures from actual 2003 and 2004 data are minimized. This calibrated model is then used later in the paper in conjunction with the standard model in making estimates of short-term abatement in response to a carbon price in 2005 and 2006.

1. Standard model vs. actual generation for 2003 & 2004

In a first instance, the model E-Simulate has been run, using the power plant stock as it existed in 2003 and 2004 along with aggregate zonal demand and fuel prices for those years assuming standard availabilities for power plants and uniform fuel prices. These last two parameters will be used in the second step to calibrate the model. Electricity generated from nuclear, hydro, wind, biomass and waste is matched to actual values as closely as possible in order to focus the discussion on generation from fossil fuels, i.e., coal, lignite, natural gas and oil, which are the sources of emissions.

In calibrating the model, a first issue is whether it is more important to use the amounts of generation in the different zones or the fuel generation shares within each zone as the basis of the calibration. These two measures are strongly correlated. If a certain country were modeled having its full capacity of a certain type of (e.g. a lignite fired) power plant constantly available, when in reality this is not the case, not only would the country’s fuel shares for electricity generation be affected, but also the trade between zones and therefore the overall electricity generation per zone.

In comparing the standard model output for 2003 and 2004 against actual generation by zone, a clear general tendency can be observed. In nearly every zone, the model is predicting more coal and lignite use at the expense of natural gas and oil than is actually the case. For the 21-country system, E-Simulate yields a coal/lignite share of 34% in 2003 and 31% in 2004, when in fact these shares were 29% and 28%, respectively. Conversely, it posits natural gas/oil shares of 17% in 2003 and 20% in 2004 compared to actual shares of 22% and 23%, respectively.

A number of factors could cause these divergences but most can be summarized as less availability of the coal and lignite plants than what is suggested by the standard availability factors, particularly in the UK, Poland, Central Eastern Europe and Germany (zones 1, 7, 8 and 10, respectively). Lower availability could be the result of technical difficulties at the plant, lack of sustained maintenance, or lack of fuel. Natural gas or coal prices that differ from the uniform price assumed in the model, the National Balancing Point gas price and ARA coal price, could also lead to this result. However, in the zone that is most liberalized (#1: UK, IRL), over-use of coal is also observed.

2. Model calibration

Accordingly, the main correction in developing a "calibrated" model is to adjust coal and lignite availabilities downward and only secondarily to introduce factors that would change the price of certain fuels.

An important issue in calibrating the model concerns how to measure the improvement of a certain correction. With demand for electricity fixed by zone, any change in plant availabilities or relative prices to diminish the divergence in one part of the system may lead to greater divergences in other parts of the system. As a measure of the improvement overall, the Root Mean Square (RMS) value of the absolute differences of the simulated and real values for both years is taken:

$$RMS = \sqrt{\frac{1}{n} \cdot \sum_{i=1}^{n} x_i^2} \quad (1)$$

With x the absolute deviation, specified below.

The RMS summary statistic is measured in three different ways:

- RMS1: The RMS of all deviations x in generation per fuel per zone
- RMS2: The RMS of all deviations x in total generation per zone
- RMS3: The RMS of all deviations x per fuel in total generation (all zones together)

The correlation of zonal generation with fuel shares noted above will tend to cause the three measures to move together so that corrections in coal plant availabilities, for instance, also improve the error in total generation by zones. This was not always the case, however; and where a correction led to conflicting results, getting the zonal fuel share correct took priority over zonal generation since it is the switching from coal to natural gas that is the primary means of short-term abatement. Finally, changes in plant availability and relative fuel price were maintained for both years of the calibration period. This treatment resulted in certain changes improving the fit in one year but worsening it in the other year. In such cases a balance had to be found. In the end, the calibrated model is the result of an iterative process that sought to minimize the RMS for the system as a whole. The most important changes were the following:

Zone 1 (UK, Ireland): Decrease in the availability of coal fired power plants;

Zone 2 (Iberian Peninsula): A different price for natural gas[3];
Zone 5 (Italy): A different price for natural gas[4];
Zone 7 (Poland): Decrease in the availability of coal and lignite fired power plants;
Zone 8 (Central East Europe): Decrease in the availability of coal and lignite fired power plants;
Zone 10 (Germany): Decrease in the availability of coal and lignite fired power plants.

Table 2 and Table 3 list the different RMS values before and after calibration, for 2003 and 2004, respectively. In these tables, also a value for the RMS based on cross border transfer (RMS cbt) is presented. This criterion will be defined and discussed later.

Table 2: RMS values to measure calibration, 2003.

2003	before calibration	after calibration	difference	relative difference
RMS1	35205	7233	27972	79%
RMS2	9345	6211	3134	34%
RMS3	47114	7644	39470	84%
RMS cbt	7990	7138	852	11%

Table 3: RMS values to measure calibration, 2004.

2004	before calibration	after calibration	difference	relative difference
RMS1	65631	21555	44076	67%
RMS2	34229	11353	22876	67%
RMS3	96124	35472	60653	63%
RMS cbt	7310	6788	522	7%

From these tables, it is clear that calibrating the model in all cases reduces the RMS, especially the RMS values calculated per fuel, i.e., RMS1 and RMS3. Recall that the generation per zone and fuel, linked to RMS1 is the one actually used for calibration.

Pertinent simulation results for the calibrated and standard models are presented in Table 4 and Table 5 for 2003 and 2004. Electricity generation over the whole year is grouped per fuel and aggregated over all the zones modeled. When expressing the electricity generation as fraction of the total share (last three rows of each table), a very good match exists between the calibrated model and actual numbers.

For coal, a slight deviation in both simulated years still persists. However, since this deviation has a different sign in the two years, a middle course had to be found.

Table 4: Generation comparison between historic values and simulation results, i.e., of both standard (STA) model (before calibration) and calibrated (CAL) model, for the year 2003.

2003	Generation (all zones)	[TWh]

[3] This change links the gas price to the oil price profile, thereby also resulting in a gas price that was on average higher than the NBP price.
[4] Ibid.

	Nuclear	coal	lignite	Gas	oil	hydro	oth. ren.	other	total[a]
Historic real	937.2	598.0	268.9	529.7	131.6	387.5	83.7	50.8	2987.1
STA simulation	929.0	690.7	331.3	457.6	66.0	387.5	85.2	65.2	3012.5
CAL simulation	939.7	619.6	271.7	531.4	122.1	387.5	85.2	55.3	3012.5

	Share in total generation (all zones)				[%]				
	nuclear	coal	lignite	Gas	oil	hydro	oth. ren.	other	
Historic real	31%	20%	9%	18%	4%	13%	3%	2%	
STA simulation	31%	23%	11%	15%	2%	13%	3%	2%	
CAL simulation	31%	21%	9%	18%	4%	13%	3%	2%	

[a] Note that a possible minor difference exists on the total actual and simulated generation. This is due to possible deviations in total demand modeled (which results from a different data source), or from a different use of pumping units, which can affect total generation.

Table 5: Generation comparison between historic values and simulation results, i.e., of both standard (STA) model (before calibration) and calibrated (CAL) model, for the year 2004.

2004	Generation (all zones)				[TWh]				
	nuclear	coal	lignite	gas	oil	hydro	oth. ren.	other	total[a]
Historic real	948.0	585.2	270.0	572.9	110.9	402.8	108.9	53.3	3050.5
STA simulation	935.7	605.0	328.4	553.9	55.4	402.6	108.9	64.4	3054.4
CAL simulation	947.2	570.8	270.8	602.3	97.2	402.6	108.9	54.4	3054.2

	Share in total generation (all zones)				[%]				
	nuclear	coal	lignite	gas	oil	hydro	oth. ren.	other	
Historic real	31%	19%	9%	19%	4%	13%	4%	2%	
STA simulation	31%	20%	11%	18%	2%	13%	4%	2%	
CAL simulation	31%	19%	9%	20%	3%	13%	4%	2%	

[a] See footnote *a* of Table 4.

Since cross-border or inter-zonal flows are often an order of magnitude smaller than actual generation, these flows were not used for calibration. Nevertheless, the calibration improved the correspondence between actual and modeled flows. ‘RMS cbt’ in Table 2 and Table 3 presents the RMS of the absolute deviations between actual and simulated inter-zonal flows. An improvement is demonstrated, but not a large one. As shown in the tables below, the directions of all major flows are correct and the magnitudes generally comparable. The largest discrepancies between actual conditions and the calibrated model are experienced in the flows from France to Germany. Table 6 and Table 7 present both the actual flows and those in the calibrated model for the four largest actual flows. These numbers show that the largest actual electricity transfers in Europe correspond to a large extent to the biggest simulated flows.

Table 6: Four largest actual flows, together with simulated values in the calibrated simulation (CAL), 2003; the number in brackets indicates the rank of the flow, when all 16 flows are sorted.

2003 FROM	NET VALUES TO	REAL [GWh]	CAL Simulation [GWh]
Zone 9 AT, CH	Zone 5 IT	27589 (1)	17652 (2)
Zone 4 FR	Zone 10 DE	20075 (2)	7520 (10)
Zone 10 DE	Zone 3 BE, NL, LU	18559 (3)	15223 (4)
Zone 4 FR	Zone 5 IT	17591 (4)	20883 (1)

Table 7: Four largest actual flows, together with simulated values in the calibrated simulation (CAL), 2004; the number in brackets indicates the rank of the flow, when all 16 flows are sorted.

2004 FROM	NET VALUES TO	REAL [GWh]	CAL Simulation [GWh]
Zone 9 AT, CH	Zone 5 IT	21522 (1)	21782 (1)
Zone 10 DE	Zone 3 BE, NL, LU	20976 (2)	17589 (4)
Zone 4 FR	Zone 5 IT	16581 (3)	20711 (3)
Zone 4 FR	Zone 10 DE	15086 (4)	3195 (12)

III. THE TOPOGRAPHY OF ABATEMENT

Before applying the standard and calibrated versions of E-Simulate to 2005 and 2006 data, we develop what can be called the topography of fuel switching in the electric power system. The purpose in this section is not to simulate the actual CO_2 price, fuel prices, and load conditions but to explain how these factors affect abatement. As will become readily clear, there is no single constant relationship between the price of CO_2 and abatement. The quantity of abatement from fuel switching that will be obtained for any given price of CO_2 is heavily dependent on the actual hourly load, which varies significantly over diurnal, weekly, and seasonal cycles, and on the relative price of natural gas and coal, which varies from day to day. To illustrate these relationships, the model is utilized in its standard, non-calibrated configuration.

A. *The effect of load*

1. Generation and emissions with invariant fuel prices

One condition for fuel switching is the availability of sufficient generation capacity with lower emissions. If every power plant in the system is running at its full capacity, no fuel switching potential remains. If, however, load is relatively low and most of it is met with coal fired generation, a large share of gas fired power plants would be available to replace the coal plants given the correct economic incentives (these effects are discussed for several European countries in Delarue and D'haeseleer (2008), and for Belgium specifically in Delarue and D'haeseleer (2007)). Accordingly, this section focuses on the relationship between load level and the quantity of abatement that can be obtained through fuel switching in response to a carbon price. Since this potential abatement is also dependent on fuel prices and in order to isolate the effect of load on abatement, constant fuel prices are assumed throughout the year at the average prices in 2005 (5.7 euro/GJ for natural gas and 1.9 euro/GJ for coal).

Electricity load varies greatly over typical diurnal cycles and with a seasonal variation. When run over a typical annual period, E-Simulate produces 8760 values for electricity generation for each hour of the year with corresponding CO_2 emissions. Figure 3 (a) presents these values, sorted according to load. E-Simulate's EU-wide generation varies from about 230 GW with less than 100,000 tons of CO_2 emissions per hour during summer off peak hours to about 430 GW and more than 200,000 tons of CO_2 emissions per hour during winter peak hours. When these hourly plots are fitted with a linear curve, a relatively constant slope of 600 ton/GWh is obtained. This reflects the average carbon content of the mix of fossil fuels used in the available generating plants as they are activated to meet increasing EU-wide load.[5]

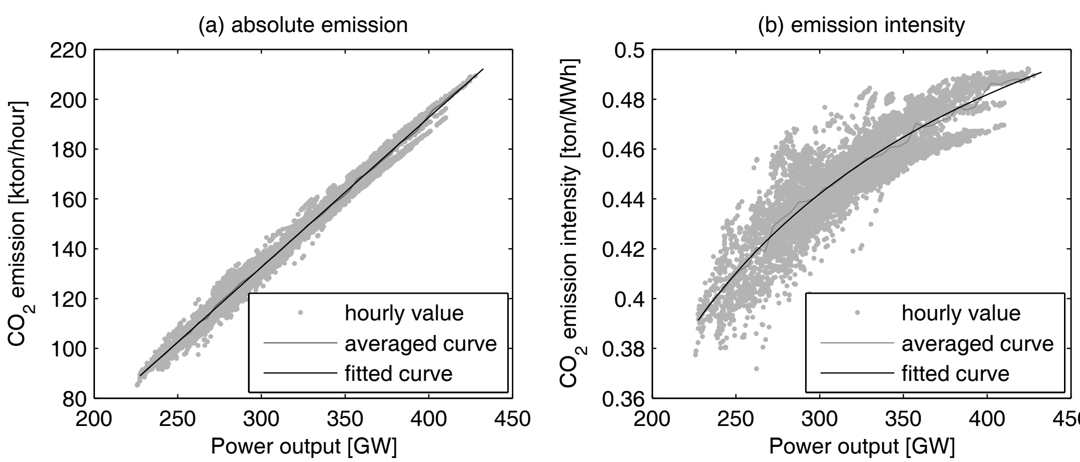

Figure 3. Hourly CO_2 emissions, with both an averaged and linear fitted curve; (a) absolute emissions [kton/hour]; (b) emission intensity [ton/MWh].

[5] Coal burned at 36% efficiency: 951 ton/GWh; Gas burned at 50% efficiency: 413 ton/GWh; Gas burned at 36% efficiency: 574 ton/GWh; Oil burned at 35% efficiency: 771 ton/GWh.

In the same manner, Figure 3 (b) depicts the system-wide CO_2 emissions intensity[6] as load increases. With a relative low carbon mix of generating plants at low loads (nuclear, hydro), the average intensity starts out at about 400 kg per MWh but it rises as load increases and then flattens out at intensities of a little below 500 kg/MWh as load reaches peak levels. The slight curvature reflects the increasing contribution of fossil-fired generation as EU-wide load increases at these fuel prices.

2. CO_2 price effects

Figure 4 shows average hourly CO_2 emissions at CO_2 prices ranging from zero, which reflects business-as-usual (BAU) conditions, to 100 euro/ton and the resulting abatement as a function of load[7]. As load increases, emissions increase regardless of the CO_2 price, but the extent to which emissions are reduced in response to any given carbon price depends on load.

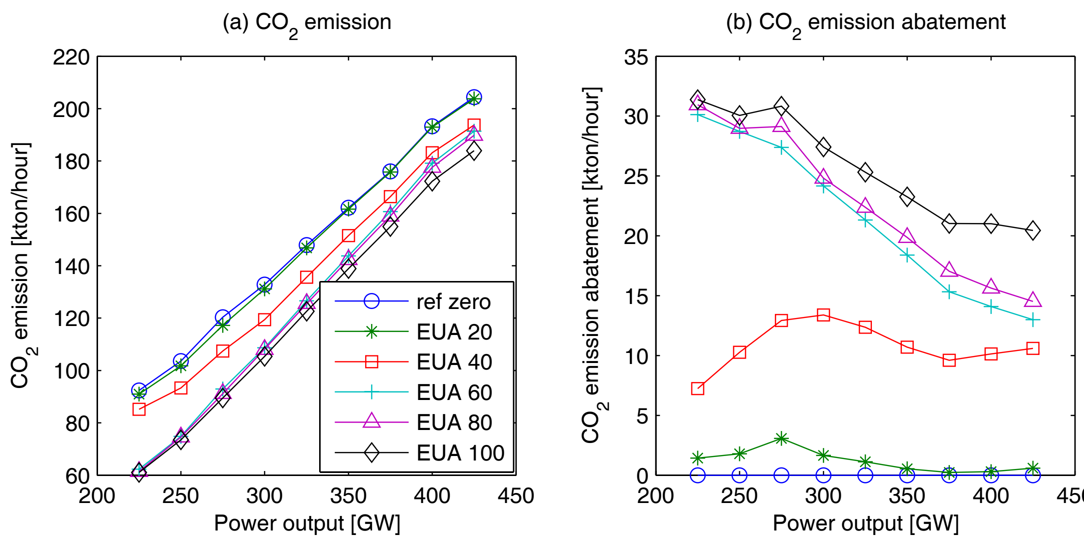

Figure 4. (a) CO_2 emission at different EUA prices; (b) corresponding CO_2 abatement (compared to zero EUA reference case). The legend in (a) applies also in (b).

With a constant fuel price for natural gas that is three times the coal price, a 20 euro/ton CO_2 value yields very little abatement. Some abatement from fuel switching occurs at low load levels, but a CO_2 price of 20 euros is not high enough to encourage much fuel switching at the assumed fuel prices. However, the picture for a EUA price of 40 euro/ton is quite different. In this case, a relative constant abatement of about 10 kton/hour can be noticed throughout the entire load spectrum. Still higher CO_2 prices are sufficient to cause lower emitting plants (mostly, natural gas) to substitute for coal, especially at the lower load levels, and thereby to create significant abatement. Nevertheless, abatement

[6] This emission intensity is defined as the absolute emission during a specific hour divided by the energy produced during that hour.
[7] These curves are constructed by grouping (averaging) the 8760 data points in steps of 50 GW.

diminishes as load increases since the higher load pulls more gas-fired generation into service in the BAU case and thereby diminishes the gas-fired capacity that is available to substitute for coal when the CO_2 price is high enough to induce switching.

Figure 5 presents (a) the corresponding 3D representation and (b) the contour plot of the abatement. In these figures, the extent to which CO_2 abatement changes with load and EUA price can be seen by drawing a straight line from any point on the appropriate axis.

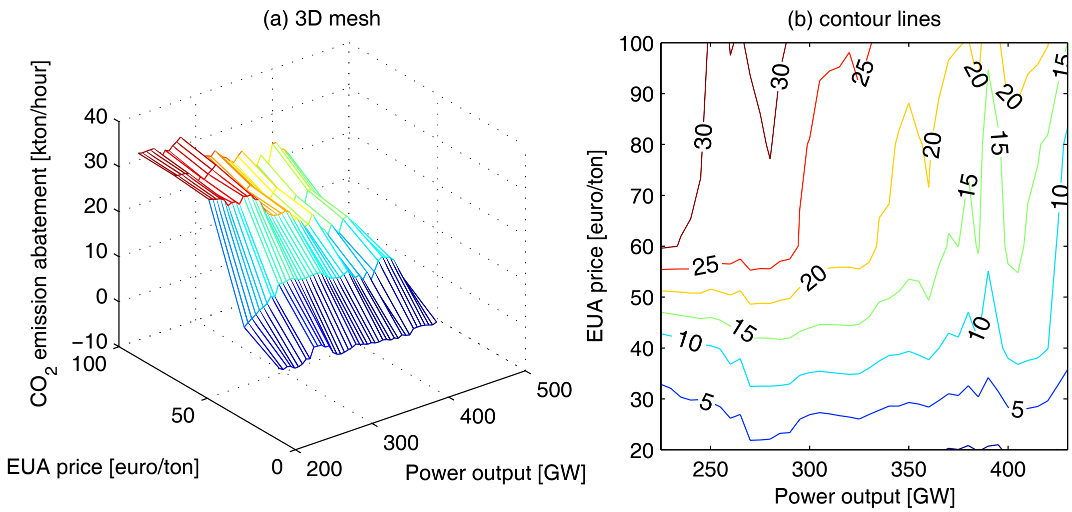

Figure 5. (a) 3D mesh of the power output, EUA price and abatement relationship; (b) corresponding contour lines of the abatement [kton/hour].

A higher CO_2 price yields more abatement for any given level of load, but the amount of abatement for any given CO_2 price can vary greatly depending on load. Given typical fuel price relationships and the historical configuration of plant types, a carbon price will have its greatest effect at relatively low load levels when more lower emitting capacity is available. As load increases, it becomes increasingly expensive to sustain the same level of abatement. Alternatively, at any given CO_2 price, the amount of abatement will diminish as load increases. This tendency is particularly pronounced when CO_2 price levels are high enough to trigger significant switching and abatement at low load levels when more gas capacity is available.

B. *The effect of fuel prices*

For the purposes of this paper, fuel and carbon prices are taken as exogenously determined[8]. Several papers have shown some influence of oil or natural gas prices on the EUA price, but this effect is weak and there are other factors that also influence EUA

[8] Delarue et al. (2007) discuss the effect of the seasonal natural gas price profile on fuel switching. They also investigate the effects of a (fictive) EUA price that would be fully correlated with the natural gas price.

prices.[9] Also, to the extent that fuel switching occurs, the demand for one fuel is increased at the expense of the competing fuel; however, it can be doubted whether the magnitudes involved are large enough to have a significant effect on the NBP natural gas price and the ARA coal price, both of which reflect conditions in significantly larger world markets.

1. Development of the switching band

E-Simulate minimizes the cost of dispatch, that is, the marginal cost of burning a certain fuel in a particular type of power plant. In the case where no carbon cost is imposed, this marginal cost is equal to the fuel cost divided by the plant's efficiency[10]. Since the fuel and marginal cost are linearly related, the criterion to be looked at when focusing upon fuel prices is the price ratio between different fuels. If, for instance, all the fuel prices would be doubled, the outcome of a simulation will not change (still assuming no carbon cost).

The EUA price required to switch a certain coal and gas plant in the merit order depends on each plant's fuel cost, efficiency and emission rate as shown in the following illustrative example.[11] Let η_c be a coal plant's efficiency; η_g be a gas plant's efficiency; FC_c the fuel cost for coal [euro/GJ]; FC_g the fuel cost for gas [euro/GJ]; EF_c the emission factor of coal [tonCO_2/GJ]; and EF_g the emission factor of gas [tonCO_2/GJ]; then the allowance cost necessary to switch both plants in the merit order ACs [euro/tonCO_2] becomes (Delarue and D'haeseleer, 2007):

$$ACs = \frac{\eta_c \cdot FC_g - \eta_g \cdot FC_c}{\eta_g \cdot EF_c - \eta_c \cdot EF_g} \tag{2}$$

As the prices of coal or natural gas vary, the allowance cost necessary to switch both plants changes proportionally. Given plant efficiencies and emissions factors, the allowance cost that would justify switching from a coal plant to a gas plant can be expressed as a ratio of the natural gas to coal price.

Let $x = \frac{FC_g}{FC_c}$, then substituting this ratio into Eq. (2) gives:

$$ACs = \frac{(\eta_c x - \eta_g)FC_c}{\eta_g \cdot EF_c - \eta_c \cdot EF_g} = a \cdot x + b \tag{3}$$

The relationship between the gas/coal price ratio, x, and the switching price is presented in Figure 6 for several combinations of natural gas and coal plant efficiencies[12, 13].

[9] For a more extensive discussion of this complicated relationship, see Mansanet-Bateller et al. (2007), Bunn and Fezzi (2007), and Alberola et al. (2008).
[10] Efficiency is, however, not constant. As load increases, the overall plant's efficiency typically increases as well.
[11] While the discussion in this section and subsequently in this paper tends to focus on coal and natural gas, it must be noted that switching also occurs between gas and oil, oil and coal, and between lignite and hard coal, albeit in much smaller quantities.
[12] In this section, the gas price will be varied to vary the fuel price ration between gas and coal. A ratio

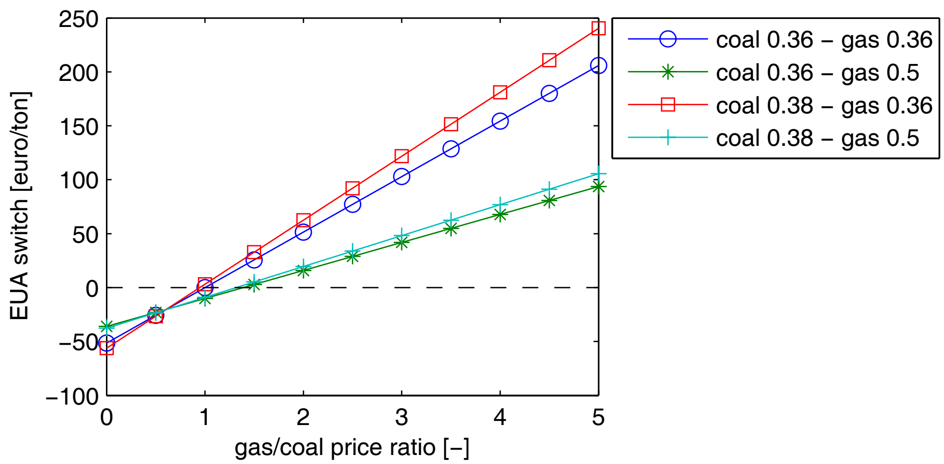

Figure 6. Relationship between gas/coal price ratio and allowance price required for switching, depicted for different combinations of efficiencies.

Equation (3) and Figure 6 illustrate an important point: switching from coal to natural gas can occur even if there is no carbon cost. A switching opportunity will exist in this case, since the value of the denominator in equation (3) is positive (this is valid for all practical circumstances, that is, when the natural gas plant has lower emissions than the coal plant). So long as coal has a particular positive price (i.e., $FC_c \geq 0$), there is a gas/coal price ratio x (or alternatively a price of natural gas) that is low enough to justify dispatching the natural gas plant in place of the coal plant even without a CO_2 price. This condition can be shown to be $x = \frac{\eta_g}{\eta_c}$, the ratio of the efficiency of t he gas plant to the coal plant. As the gas/coal price ratio diminishes, switching will occur first when the gas/coal price ratio is equal to the ratio of efficiency of the most efficient gas plant with unused capacity to that of the least efficient coal plant in service. As the gas price falls, continually more switching opportunities will occur until the most inefficient, available gas plant is dispatched instead of the most efficient coal unit. In the examples given in Figure 6, the fuel price range that would trigger switching with no carbon price starts at 1.39 (= 0.50/0.36) and ends at 0.95 (= 0.36/0.38), as illustrated by the dashed horizontal line.

A positive carbon price has the effect of shifting the switching range upward and expanding it. For instance, for the examples given in Figure 6, and at an EUA price of € 20, the switching range extends from 2.16, when the most efficient available gas plant displaces the least efficient operating coal plant, to 1.28, when all switching opportunities

from zero to 5 is considered. A ratio of zero in fact means a gas price equal to zero. This limit is rather hypothetical, although the price of natural gas in fact has been zero, for example, in the UK during several days in 2006, due to problems with the interconnector with mainland Europe.

[13] The ranges of efficiencies used in this figure do not cover very efficient (e.g. 55 %) gas or very efficient (e.g. 45 %) coal plants, since these plants are only present in very limited numbers. The largest part of the current European power plants is covered by the ranges used.

are exhausted.

Alternatively, and perhaps more intuitively, a ‘switching band’ can be defined as the range of EUA prices that would occasion switching for any given gas/coal price ratio. For instance in Figure 6, if the gas price was twice the coal price, there would be no switching without a carbon price; however, a carbon price of € 15.9 would switch the most efficient available gas plant for the least efficient coal plant in service and progressively more switching would occur until most opportunities are exhausted at an EUA price of € 62.5. As explained in the preceding section, both the distance of this switching band and how densely it is populated depend on the demand that is placed on the electrical system, which, with a given capital stock, determines the gas-fired capacity that is available for switching. For any given hour, switching opportunities and abatement will depend on the efficiencies and utilized capacity of the coal plants in service and the efficiency and capacity of the available lower emitting natural gas units.

2. Abatement as a function of the fuel price ratio

The preceding discussion also highlights another aspect of CO_2 emissions reduction by switching: it occurs only over certain price intervals defined by fuel and allowance prices. In general, there always exists a gas/coal price ratio that is either high enough or low enough for the abatement potential to be zero. A very low fuel price ratio will cause all available gas plants to be in service and, for any given CO_2 price, there always exists a high enough fuel price ratio to make switching economically unattractive. In order to describe this interval, a particular load must be assumed and this means a particular hour of a specified day and season. The diurnal load cycles for four representative days during the year are given in Figure 7 (a) below and the simulated CO_2 emissions associated[14] with those 96 hours is presented in Figure 7 (b) in a similar way as in Figure 3 (a).

[14] Fuel prices used for this figure are the same as the ones used in section III A, i.e., the 2005 average.

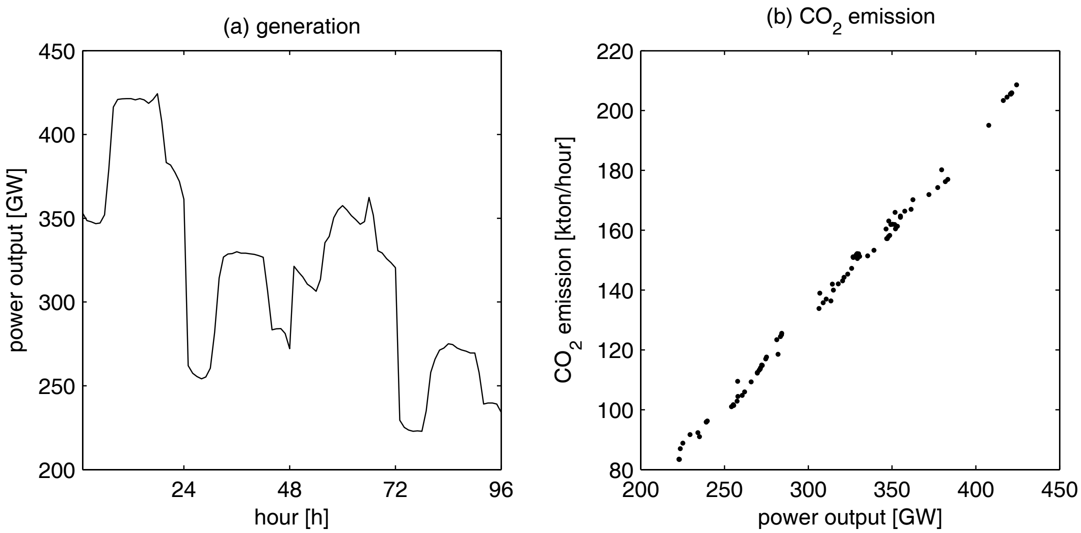

Figure 7. (a) Generation in the four representative days; (b) corresponding CO_2 emission for every simulated hour (96 in total).

Each successive 24-hour period in Figure 7 (a) represents respectively,

- A winter week day
- A summer week day
- A winter weekend day
- A summer weekend day

As can be seen in Figure 7 (b), emissions for these 96 representative hours span the whole spectrum shown earlier in Figure 3 (a). To illustrate the effect of the fuel price ratio at differing load levels, two cases will be discussed in detail: a representative winter week peak hour (at 10 a.m.) and a summer weekend off peak hour (at 10 p.m.).

Figure 8 presents the CO_2 emissions for the winter week peak hour as a function of the fuel price ratio for different EUA price scenarios, together with the corresponding abatement. The top-most line in Figure 8 (a) shows the effect of the fuel price ratio on emissions with no carbon price on this representative winter week peak hour. With very low natural gas prices, EU emissions for the hour would be 180 ktons or lower[15] but as the natural gas price rises, coal would substitute for gas generation and emissions would rise until they reach a peak of about 205 million tons when the natural gas price approaches twice the coal price.

[15] The emissions at a zero gas/coal price are again higher (at about 187 kton/hour), since in this case, with no cost for CO_2, using natural gas is actually free of cost, and therefore gas is used wherever possible. This point, therefore, should be interpreted with caution.

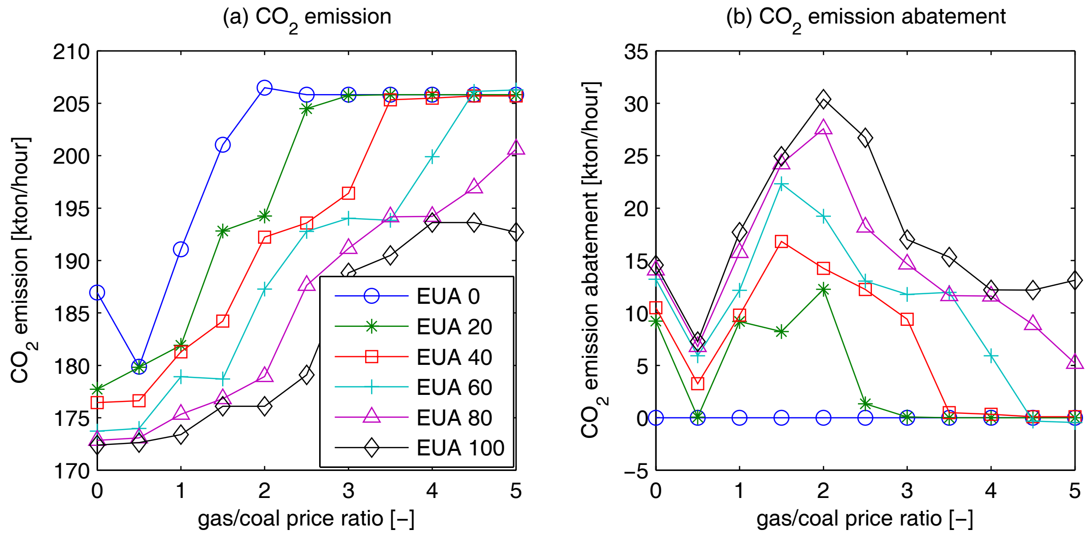

Figure 8. (a) CO_2 emission and (b) corresponding abatement, on 10 AM winter week day, under different fuel an EUA prices.

As a progressively higher EUA price is imposed in Figure 8 (a), the lines representing emissions are pushed down and stretched out to the right. The distance between the zero-price line and the other lines, shown on Figure 8 (b) indicates the abatement that would be achieved by that CO_2 price over the range of fuel price ratios. Those abatement profiles have a characteristic shape: the emission reduction associated with any given carbon price rises, peaks, and then falls as the fuel price ratio increases.

This characteristic shape reflects the interaction between the switching opportunities created by the fuel price ratio as it increases and the exploitation of those opportunities that can be economically justified by the carbon price. Higher fuel price ratios cause less gas and more coal capacity to be in service thereby creating opportunities for switching and thus abatement with an appropriate CO_2 price. In effect, higher fuel price ratios create switching or abatement opportunities until the technical maximum, defined by the lesser of existing gas-fired or coal-fired capacity, is reached. However, for any given price of CO_2, this abatement maximum may be lower, the point at which the assumed carbon price will no longer justify exploiting any more of the switching opportunities that are increasingly being made available by the higher fuel price ratio. From that point on, abatement falls as the still higher fuel price ratios reduce the number of switching opportunities that can be economically justified at the assumed carbon price. That apex is of course higher for higher CO_2 prices.

Alternatively, for any given fuel price ratio, the amount of abatement that would be achieved by progressively higher CO_2 prices, varies greatly. To take the extreme example from Figure 8 (b), the amount of abatement produced by a CO_2 price of € 100 at a fuel price ratio of 2 is about twice as much as what would result from a fuel price ratio of either 1 or 3 and about six times as much as at a fuel price ratio of either 0.5 or 5. On one side of the apex, there are progressively few switching opportunities, while on the other side progressively fewer of the available switching opportunities are economically attractive at the stated CO_2 price.

Figure 9 presents a 3-dimensional representation of these relationships, together with the contour lines.

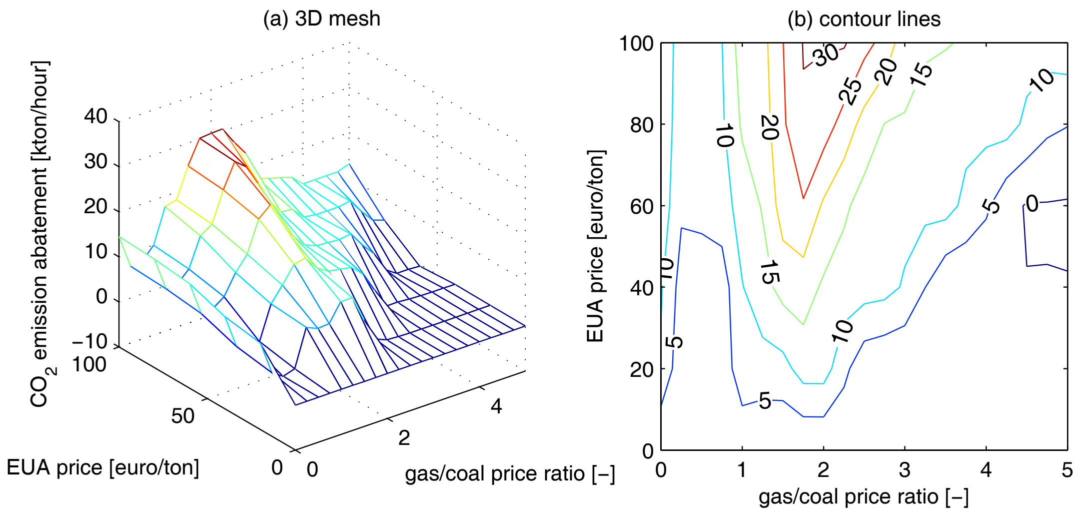

Figure 9. CO_2 emission abatement, on 10 AM winter week day, under different fuel an EUA prices; (a) 3D mesh; (b) corresponding contour lines.

At the opposite end of the load cycle (an off-peak hour on a summer week-end), the characteristic shape of the relationship between the fuel price ratio, CO_2 price and abatement is the same, but the exact topography differs somewhat as illustrated in Figures 10 and 11.

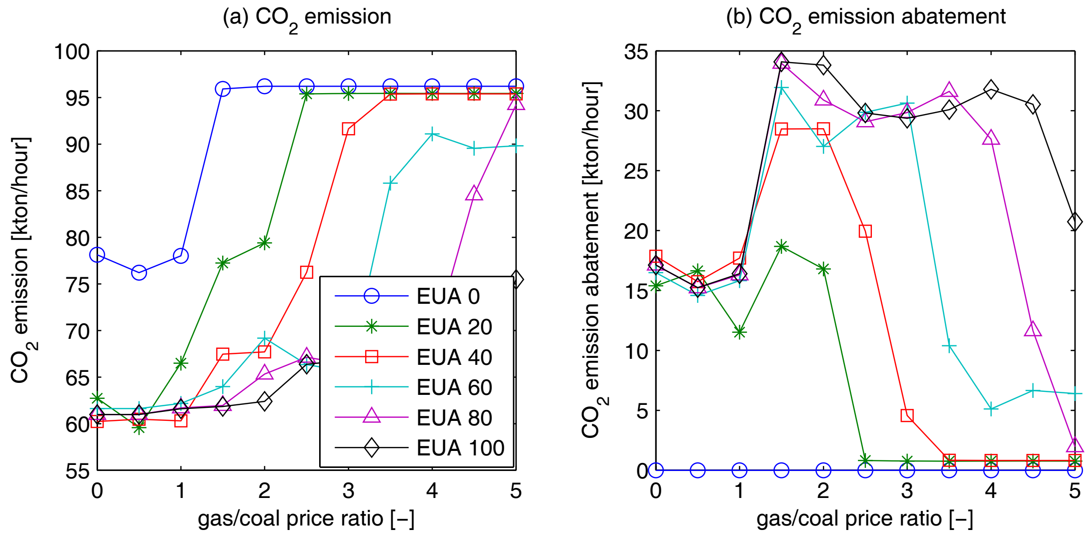

Figure 10. (a) CO_2 emission and (b) corresponding abatement, on 10 PM summer weekend day, under different fuel an EUA prices.

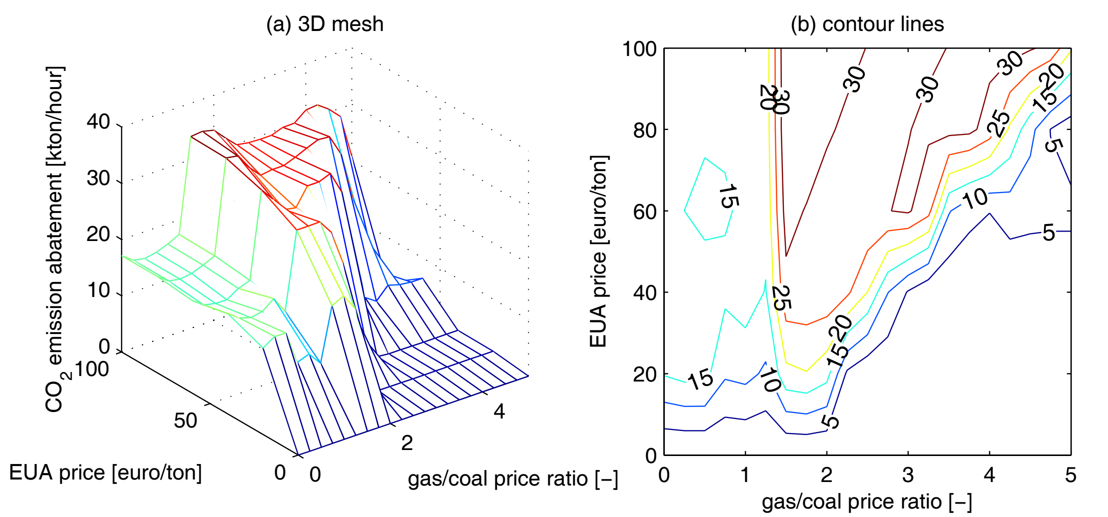

Figure 11. CO_2 emission abatement, on 10 PM summer weekend day, under different fuel an EUA prices; (a) 3D mesh; (b) corresponding contour lines.

The first point to note is that in Figure 10 (a) is that, while emissions are much lower, the potential abatement in response to a carbon price is not. In fact, it is slightly greater since more gas-fired generation is available to displace remaining coal-fired generation. A second point to note is that even a low CO_2 price creates a lot of abatement at low fuel price ratios (<1.0) and that at positive carbon prices emissions rise much less than they do on the winter peak hour as the fuel price ratio increases. It must be remembered that more efficient generation will get dispatched sooner regardless of the CO_2 price. Thus, on the winter week peak hour, most of the really good switching opportunities are unavailable since the efficient gas plants are already committed. Consequently, it does take much of an increase in the fuel price ratio to drive the rest of the gas plants out of service and for emissions to rise rapidly even at relatively high CO_2 prices. On the summer week-end off-peak hour, the amount of gas capacity available for switching is greater, so that higher fuel price ratios do not drive up emissions as quickly when a carbon price justifies the use of these more abundant and more attractive switching opportunities.

Finally, the apex in the characteristic shape of the abatement relationship illustrated in Figure 10 (b) is not nearly as peaked in the summer as it is in the winter. Instead, the relative abundance of good switching opportunities tends to create a broad plateau over a considerable range of the fuel price ratio.

More illustrations could be presented for off-peak winter hours or peak summer hours (or indeed for any hour), but they would be variations on the two cases presented above, which are sufficient to illustrate the basic topography of abatement by fuel switching through the re-dispatch of existing generating plants. For any given configuration of plants, lower load and appropriate fuel price ratios increase opportunities for switching and thereby create the potential for greater abatement in response to a given CO_2 price. At the same time, any given CO_2 price will justify only so much switching given the fuel price ratio.

3. Combining Load and Fuel Price Effects

When the effects of load and fuel prices are considered together the quantity of abatement that will be obtained for any given CO_2 price will tend to resemble a hill when abatement is plotted in three dimensions against load and the fuel price ratio. Figure 12 presents this "abatement hill" in the case of an allowance cost of 60 euro/ton (power output is averaged out in steps of 25 GW) for the 96 hours of the four simulated typical days sorted according to load.

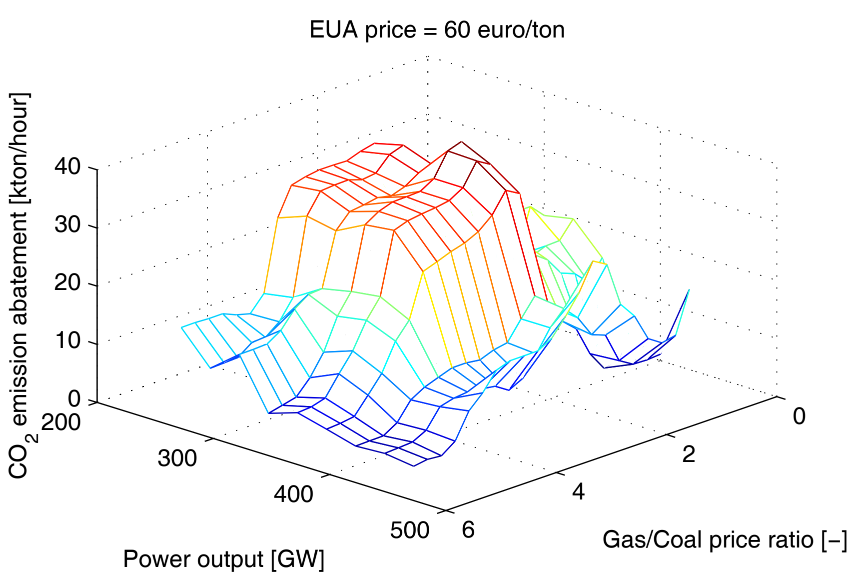

Figure 12. Abatement as function of power output and fuel price ratio, for a EUA price of 60 euro/ton.

The contours of this hill are determined by the given configuration of plants and the three factors that have been discussed in this section: load, fuel price ratio, and CO_2 price. At the hypothetical extremes of load and fuel price ratios (which are for the most part outside the range of actual experience in the European electrical system), no abatement would occur at any CO_2 price, but as one moves away from these hypothetical limits to more realistic combinations, there will be an abatement response to a CO_2 price. The steepness of the sides of the hill and the height of its summit are determined by load and the fuel price ratio.

Figure 13 presents the abatement contour lines, corresponding to figures like Figure 12, now for EUA prices ranging from 20 euro/ton up to 100 euro/ton (the 80 euro/ton case is not presented for the sake of simplicity). From these figures, one clearly distinguishes a zone with maximum abatement potential, situated at the lower load levels. This zone starts at a gas/coal price ratio of about 1, and stretches out to higher fuel price ratios, with an increasing EUA price. The low abatement potentials at high load levels[16] and/or very low or very high gas/coal prices are also clearly reflected.

[16] Note that at the highest load levels, at a gas/coal price ratio of about 1.5, a small zone of a somewhat higher abatement exists. This is in this case simply due to the higher absolute emissions.

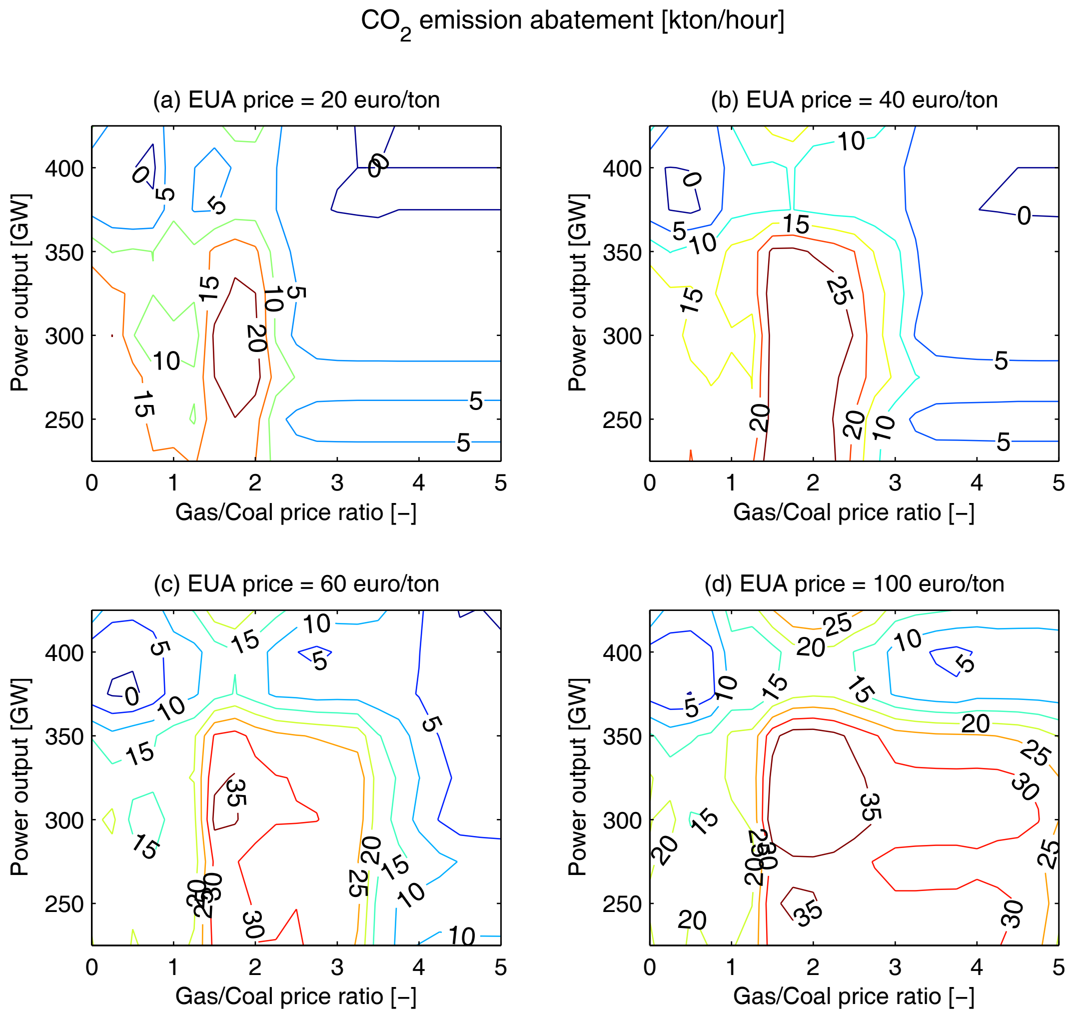

Figure 13. Contour lines of CO_2 emission abatement, expressed in [kton/hour], as function of power output and fuel price ratio. (a) EUA price = 20 euro/ton; (b) EUA price = 40 euro/ton; (c) EUA price = 60 euro/ton; (d) EUA price = 100 euro/ton.

IV. ESTIMATES OF SHORT-TERM POWER SECTOR ABATEMENT IN 2005 AND 2006

We now turn to E-Simulate to provide estimates of abatement due to the carbon price in 2005 and 2006. The year 2007 is not included due both to the lack of data on zonal demand and generation for this year at the time of writing and, moreover, to the low level of the EUA price throughout this year. Figure 14 presents the historic EUA price of the first period (2005-2007).

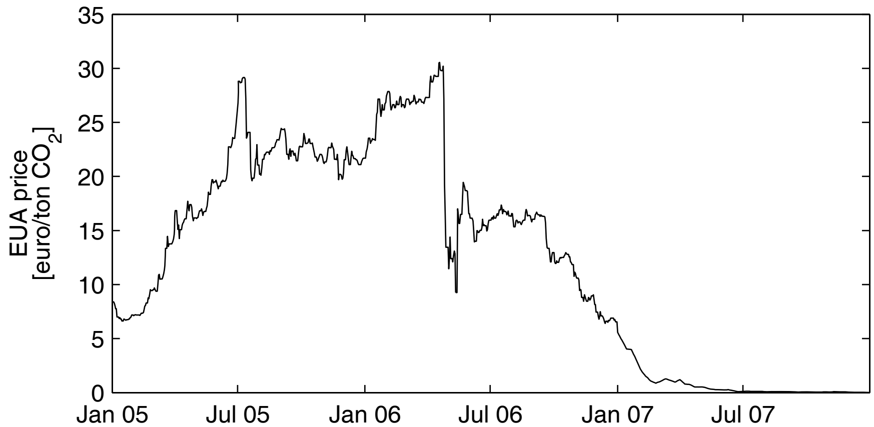

Figure 14. Historic EUA price during first trading period (2005-2007).

The model is run for both 2005 and 2006 using actual zonal demand and energy prices in both the standard (STA) and calibrated (CAL) versions in one case without a carbon price and in the other with the actual CO_2 prices. The zero CO_2 price case (ZER) provides an estimate of what emissions would have been without the EU ETS. The difference between this estimate and the corresponding model run with the actual EUA price (EUA) provides the estimate of abatement or CO_2 reduction that can be attributed to the EU ETS. The eight cases that are run are as follows.

For 2005:

- the standard model with no allowance cost (STA05ZER);
- the standard model with actual EUA prices (STA05EUA);
- the calibrated model with no allowance cost (CAL05ZER);
- the calibrated model with actual EUA prices (CAL05EUA).

For 2006:

- the standard model with no allowance cost (STA06ZER);
- the standard model with actual EUA prices (STA06EUA);
- the calibrated model with no allowance cost (CAL06ZER);
- the calibrated model with actual EUA prices (CAL06EUA).

A. *Aggregate abatement and the effect of calibration*

One convenient way to illustrate the effect of a carbon price and of calibrating the model to actual data in 2003-04 is to show the share of coal-fired generation in total supply as is done in Figures 12 and 13 for 2005 and 2006 respectively.

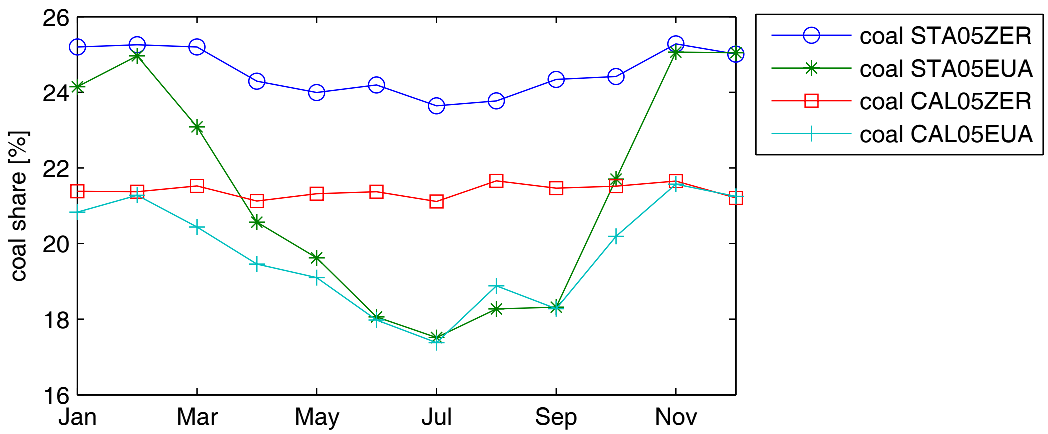

Figure 15. Share of coal fired electricity generation over the year, in different scenarios, 2005.

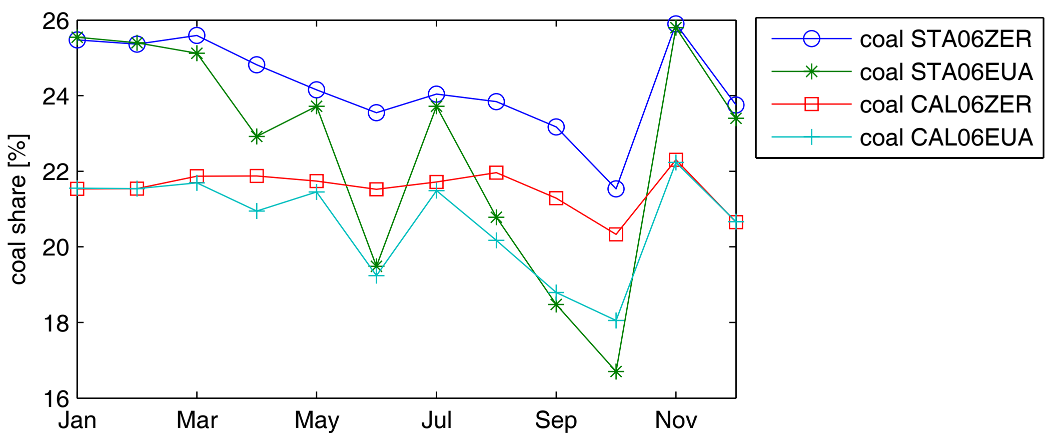

Figure 16. Share of coal fired electricity generation over the year, in different scenarios, 2006.

Two effects are readily seen in both figures although most clearly in 2005. [17] First, the CO_2 price causes the coal share to decline markedly during the summer when more gas-fired capacity is available and relatively little during the winter when the opposite condition obtains. Absent the CO_2 price, the coal share would remain relatively constant throughout the year. Second, the share of coal during the winter in the calibrated version is lower than in the E-Simulate's non-calibrated, standard version. As a result, the shift away from coal in response to the EUA price is less in the calibrated version than in the standard version. Since demand is unchanged, the reduced use of coal in the calibrated

[17] The pattern in 2006 is less distinct because of the significant decline in EUA prices after the release in late April of the verified emission reports of six Member States. Those reports revealed that emissions were much lower than generally assumed. After this EUA price fall, switching only occurred to a limited extent in May. In June, however, gas prices were again sufficiently low regarding the EUA price at that time to justify switching. In July, with a high demand in the Southern European countries and gas prices rising again, little switching occurred. From the second half of August till October, all conditions favorable to switching (i.e., sufficiently high EUA and low natural gas price, moderate demand) were met again.

model implies, of course, greater reliance on lower emitting natural gas and oil generation and less abatement potential for any given CO_2 price.

Figure 17 and Figure 18 present the CO_2 emissions and corresponding abatement for all zones aggregated on a monthly basis, for all scenarios, for the years 2005 and 2006 respectively. Panel (a) in each figure presents system-wide CO_2 emissions and panel (b) gives the resulting abatement for the standard and calibrated cases. Although the patterns are different in 2005 and 2006 due to differing EUA and fuel prices, it is clear in both figures that abatement is less in the calibrated cases

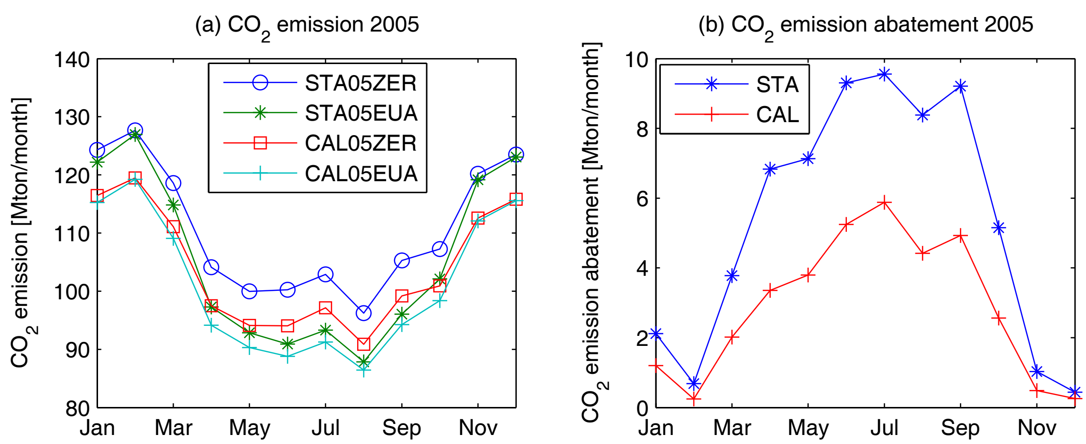

Figure 17. (a) CO_2 emission and (b) corresponding abatement in both STA and CAL simulations, for the year 2005.

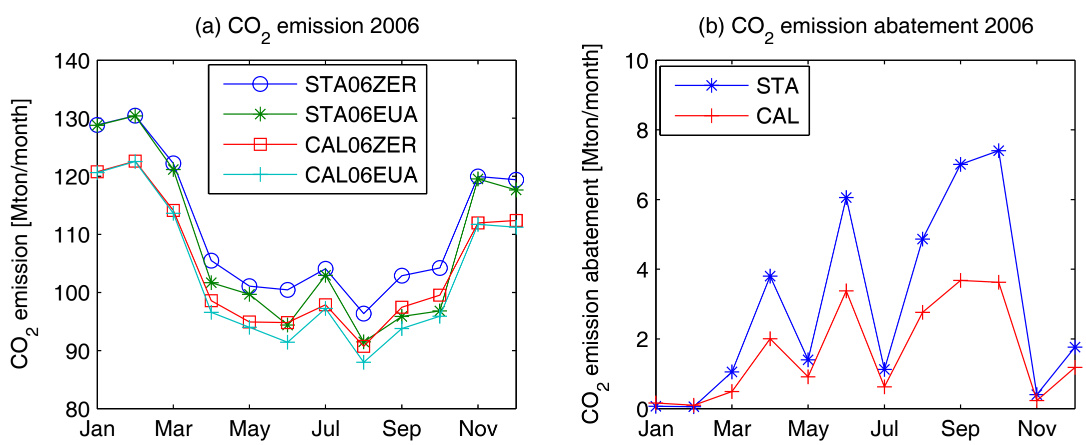

Figure 18: (a) CO_2 emission and (b) corresponding abatement in both STA and CAL simulations, for the year 2006.

The summary EU-wide results for abatement are presented in Table 9 below. These figures are the sums of the monthly plots on Figure 17 (b) and Figure 18 (b). The calibrated version provides a lower estimate because when matched with actual data in 2003 and 2004 the model was found to predict more coal generation, and correspondingly less natural gas and oil generation, than was actually occurring in those years (as discussed earlier).

Table 9. Final estimates for CO_2 emission abatement, in both 2005 and 2006, in the STA and CAL simulations.

CO_2 emission abatement [Mton]		
	STA	CAL
2005	63.62	34.41
2006	35.01	19.15
Total	98.63	53.56

When considering the effect of calibration on the estimate of abatement, it must be remembered that the calibration implicitly assumes that the constraints operating on plant availabilities in 2003 and 2004 remained valid in 2005 and 2006. While some factors could be expected to remain constant, such as plant-specific lower availability or efficiency, other factors, such as temporary shut-downs due to some malfunction or maintenance problem in 2003 or 2004 would typically not be applicable in 2005-06.

As a check on the validity of the calibration, the EUA cases for 2005 and 2006 in both implementations (STA and CAL) could be compared with actual data for these years. Table 10 compares the coal and gas use in the UK with actual use for the two versions when run with the actual EUA prices.[18]

Table 10. Model predictions compared to actual generation in 2005 and 2006 for the UK (% error using EUA runs).

	2005		2006	
	CAL	STA	CAL	STA
Coal generation	- 4.5 %	+ 22.0 %	- 7.1 %	+ 24.2 %
Natural gas generation	+ 6.1 %	- 17.2 %	+ 6.1 %	- 26.0 %

As can be readily seen, the non-calibrated, standard version continues to significantly over-predict the amount of coal use and to under-estimate the amount of natural gas use in both years. The calibrated model is certainly closer to the reality, although for these two years it slightly but increasingly under-predicts the amount of coal use. With only two observations, this error could be random, but it would also be consistent with a greater than usual amount of shut-downs in 2003-04 or other trends towards increasing use of coal-fired power plants. In any case, this comparison both shows that the calibrated case is closer to the actual figures than the standard case and suggests that the calibrated case can be viewed as a conservative, minimum estimate of the amount of abatement occasioned by fuel switching in the power sector due to the EU ETS. On this basis[19], a

[18] The UK is used as an example because of the ready availability of generation data by fuel type for 2005 and 2006 (BERR, 2007) and the UK's importance in fuel switching as will be explained below.
[19] Note that the estimated error on the abatement will be lower than the deviations reported in Table 10,

reasonable, conservative estimate for CO_2-price-induced abatement from the power sector is about 35 million tons in 2005 and 20 million tons in 2006, or about 1.75% and 1.0% of the capped emissions in those years.

B. *The Timing of Abatement*

One of the most striking features of the preceding discussion, and as depicted in Figure 17 and Figure 18, is both the seasonal pattern of abatement through switching and its high variability even within a given season. Figure 19 and Figure 20 depict the relationship between abatement, the EUA price and fuel prices as the latter evolved through 2005 and 2006. Each plot point is a daily value for the EUA price, the switching band determined by coal and natural gas prices that indicates what the EUA price should be to obtain switching and the abatement estimate for the CAL case. The switching band is constructed as follows. The lower bound of this band presents the allowance cost required to switch a 50 % efficient gas plant with a 36 % efficient coal plant, calculated with fuel prices of the actual day. The upper bound is set at the switching point of a 36 % efficient gas plant with a 38 % efficient coal plant. When EUA prices are situated in this band, fuel switching and abatement can be expected[20].The efficiencies used correspond to the ones used in Figure 6.

since it results from taking the difference between the ZER and EUA scenarios (in both CAL and STA cases).

[20] This band is only an indication of what the EUA price should be to expect fuel switching. Fuel switching could already occur at lower EUA prices, for example when the efficiency of the gas plant would be higher than the value used to calculate the lower bound. Abatement can also result from switching that occurs between fuels other than gas and coal.

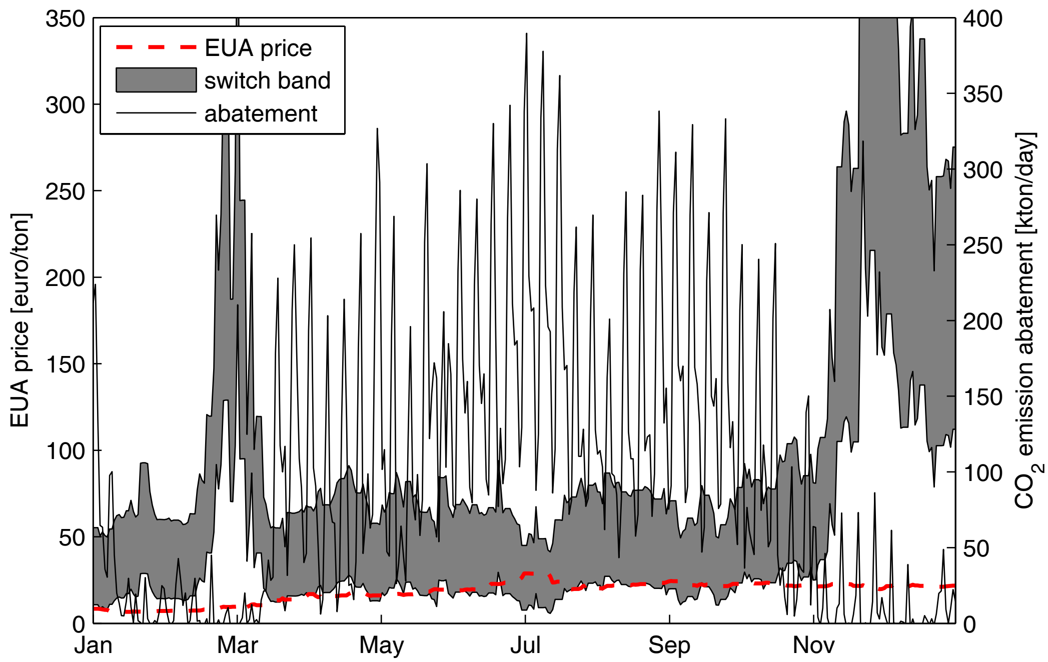

Figure 19. Historic EUA price and switching band (based on coal and gas price; lower bound: efficiency gas plant: 50 %, efficiency coal plant: 36 %; upper bound: efficiency gas plant: 36 %, efficiency coal plant: 38 %), together with the simulated abatement in the CAL case, 2005.

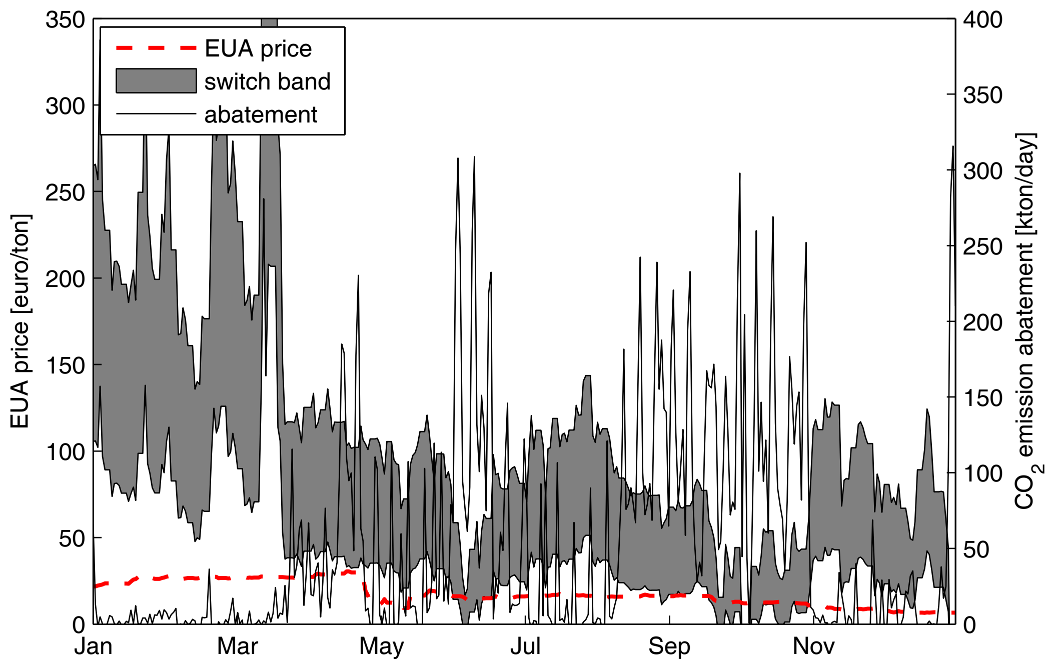

Figure 20. Historic EUA price and switching band (based on coal and gas price; lower bound: efficiency gas plant: 50 %, efficiency coal plant: 36 %; upper bound: efficiency gas plant: 36 %, efficiency coal plant: 38 %), together with the simulated abatement in the CAL case, 2006.

These figures reveal a lot about the interplay of the various factors determining abatement. First, as already noted most of the abatement occurs between April and October. This reflects the circumstance that more unused gas generating capacity is available because of the lower load demand during the summer months. Moreover, the jagged abatement line reflects the difference between demand on week-days and week-ends during the summer. For any given EUA price, there is more abatement on week-ends than on week-days, and at night than during the day, because more gas capacity is available to be switched. Table 8 presents the average abatement of all the week and weekend days of the year. The contribution during weekend days is clearly higher (a factor of more than two). The split up between day and night time is less spectacular yet still present.

Table 8: Average abatement on week and weekend days and day and night time.

	week day	weekend day	day	night
	[kton/day]		[kton/hour]	
2005	65.3	166.0	3.3	4.5
2006	37.4	89.7	2.1	2.3

This seasonal and weekly effect is especially pronounced because the most efficient gas plants are committed first to meet demand regardless of the carbon price. As demand is reduced, not only is more gas capacity made available but that capacity is more efficient and thus requiring less of an incentive in the form of the EUA price to substitute for a coal plant in staying on line to meet the reduced load.

The effect of the fuel price spread is also readily evident from Figure 19 and Figure 20. When the fuel price ratio was particularly favorable to switching for a brief period in June 2006 and for a longer period in the fall of 2006, abatement increased markedly. Interestingly, when fuel prices were least favorable to switching, for a brief period in March 2005 and from November 2005 through March 2006, there would not have been much switching anyway because of the high demand for power during the winter season.

The effect and relative importance of the EUA price can be observed over the period from April through June 2006. As the EUA price rose to 30 euros in mid-April with relatively unchanging fuel prices, abatement also rose, only to fall significantly along with the EUA price in late April. Still, despite the low EUA price in May, abatement was about the same as in early April when the EUA price was some 50% higher because gas capacity that would otherwise have been taken out of service was available to substitute for coal. Then in June 2006, a sharp increase in abatement can be observed in response both to the more favorable fuel price ratio and the lower demand for load.

Table 9 and Table 10 present values for the average generation level, gas/coal price ratio and allowance price, together with simulated abatement in both the STA and CAL cases, split up on a quarterly basis for the years 2005 and 2006 respectively. These tables clearly show that abatement occurs mainly in summer, due to a combination of lower load and lower gas prices. For both 2005 and 2006, between 70% to 80% of the abatement for the whole year occurred in the second and third quarters.

Table 9: Quarterly split up of generation, gas/coal price, EUA price and abatement, 2005.

2005		Q1	Q2	Q3	Q4
average generation	[TWh/day]	8.7	7.4	7.4	8.2
average gas/coal price	[-]	2.6	2.1	2.1	5.2
average allowance price	[euro/ton]	9.0	18.4	23.2	21.9
STA abatement	[Mton]	6.2	22.4	26.9	6.3
CAL abatement	[Mton]	3.4	12.6	16.0	3.5

Table 10: Quarterly split up of generation, gas/coal price, EUA price and abatement, 2006.

2006		Q1	Q2	Q3	Q4
average generation	[TWh/day]	8.8	7.5	7.4	8.2
average gas/coal price	[-]	4.8	2.5	2.3	2.0
average allowance price	[euro/ton]	26.1	19.0	15.9	9.4
STA abatement	[Mton]	1.1	11.2	12.8	10.0
CAL abatement	[Mton]	0.7	6.2	6.9	5.3

When comparing 2005 with 2006, there was more abatement in 2005 for the first three quarters of the year because of the more favorable fuel price ratios. For the fourth quarter, the situation reverses. The much lower natural gas prices in the fourth quarter of 2006 led to more abatement than in the year-before quarter.

C. *Geographic distribution of abatement in the EU ETS*

The geographic distribution of abatement within the EU power system is not uniform, as might be expected from what has been discussed already. The distribution of abatement will depend on not only where the emissions are, but also and more importantly the capacity and utilization of gas and coal-fired generation. Figure 21 and Figure 22 present abatement by the E-Simulate zones for 2005 and 2006 respectively in both absolute and relative terms.

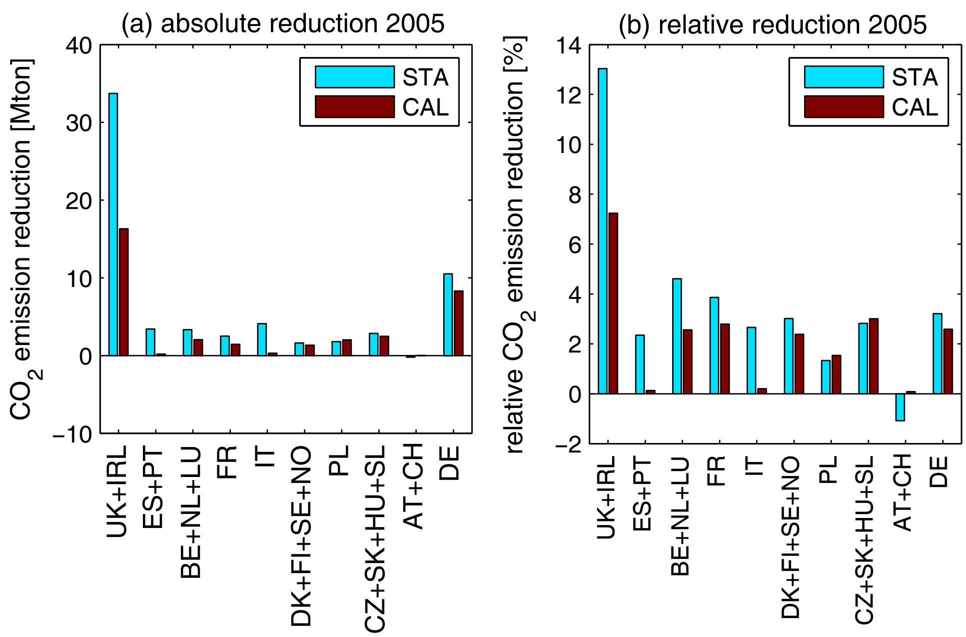

Figure 21. (a) Absolute and (b) relative CO_2 emission reduction in the different zones, in both the STA and CAL simulations in 2005.

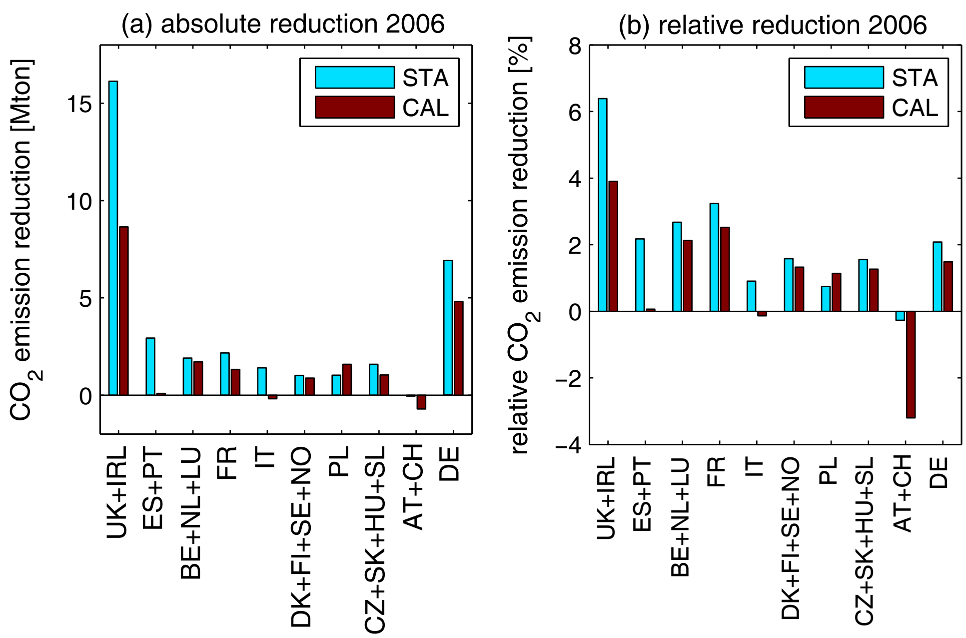

Figure 22. (a) Absolute and (b) relative CO_2 emission reduction in the different zones, in both the STA and CAL simulations in 2006.

Regardless of the version of the model used or the year, the bulk of the abatement occurs in the UK with Germany in second place but well behind. The reason is not that coal-fired emissions are more in the UK than in Germany, but there is more gas-fired capacity. Both countries have large coal-fired generating capacity—the UK with about 30 GW and

Germany with 50 GW (including lignite)—but the UK has more gas-fired capacity, 30 GW, in contrast to the 20 GW in Germany of which about half is CHP and therefore typically not part of the gas-fired capacity that can be readily switched when the economic incentives are right. When compared in relative terms, the UK is still the location of the largest percentage reduction, but the other zones are more equal with reductions usually around 2% of BAU emissions. In the calibrated version, the abatement is less in most zones, but the distribution of EU-wide abatement among zones is largely the same.

Most of the abatement occurs through switching from coal to natural gas generation within each zone, but a non-negligible share comes from changes in inter-zonal trade. These changes reflect the different intensities of generation in different zones as shown in Figure 23 for the year 2005, which is largely the same for 2006.

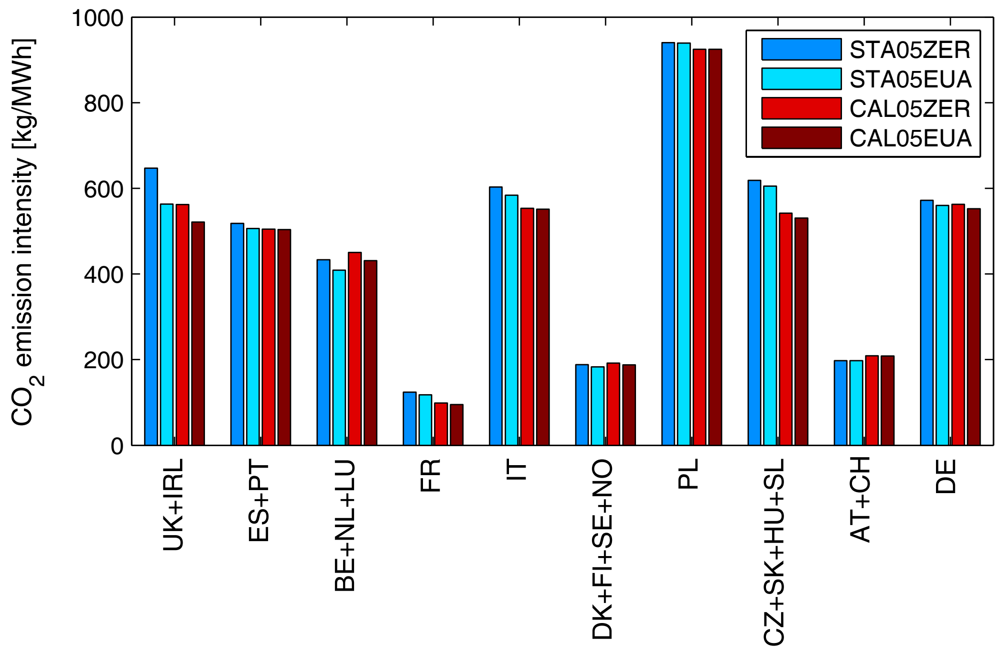

Figure 23. CO_2 emission intensity [kg CO_2/MWh], in the 10 different zones, in both the STA and CAL simulations in 2005.

The salient feature of this figure is that the CO_2 intensity of generation in France, the Nordic countries, and Austria-Switzerland is very low and that of Poland very high. The other zones differ by lesser amounts. While the presence of a carbon price causes slight changes in nearly all cross-border trades, the increases in French exports and the decreases in German and Polish power exports have the largest effect on CO_2 emission reduction, as shown in Table 11, which presents the five most important flows in the CAL case for both 2005 and 2006 and their emission reduction effects.[21]

[21] To obtain an estimate of the reduction in CO_2 emissions implied by inter-zonal transfers, the following

Table 11: Principal changes in inter-zonal power flow and their CO_2 emission reduction effect in the CAL simulations for 2005 and 2006.

	2005		2006	
	TWh[a]	Mton[b]	TWh[a]	Mton[b]
France to Germany	+ 3.98	1.86	+ 1.64	0.75
France to Benelux	+ 0.50	0.18	+ 1.36	0.48
France to the UK	- 0.23	- 0.1	+ 0.85	0.39
Germany to Benelux	- 3.65	0.41	- 2.12	0.22
Poland to Germany	- 1.01	0.35	- 1.07	0.38
Poland to Central Europe	- 1.15	0.42	- 0.67	0.24
10 other flows		- 0.1		- 0.31
TOTAL		3.00		2.15

[a] A positive shift in this context means a higher flow in the EUA scenarios than in the ZER scenarios, a negative sign indicates the reverse.
[b] The emission reduction (= difference between emission in ZER case and emission in EUA case) is listed.

The total emission reduction due to inter-zonal transfers constitutes about 10% of total EU-wide emission reduction for these years—34 Mton in 2005 and 19 Mton in 2006—but the effect of the carbon price in redistributing generation from zones with relatively higher emission intensities to those with lower intensities is evident. As reflected in the flow from France to the UK in 2005, some of the changes in cross-border trade flows increase CO_2 emissions, but they generally do not. These six principal carbon-reducing flows account for all of the emission reduction due to inter-zonal transfers in 2005 and 2006. The other flows tend to be slightly carbon increasing and none are of the same magnitude or importance from a CO_2 emission standpoint as these six.

V. SUMMARY & CONCLUSION

This paper has been motivated by a desire to explore the potential for the short-term abatement of CO_2 emissions through the redispatch of existing generating capacity in response to the carbon price established by the EU ETS. To do so, a detailed model, E-Simulate developed at the University of Leuven, that includes most of the European

formula has been applied for each connection.

$$abatement_{xy} = \Delta energy_{xy} \cdot (CI_x - CI_y) \qquad (4)$$

With
$abatement_{xy}$ the abatement attributed to an inter-zonal transfer between zone x and zone y [Mton];
$\Delta energy_{xy}$ the change in total energy transferred on the connection linking zone x and zone y, between the ZER and the EUA simulation [TWh];
CI_x the mean carbon intensity in the ZER scenario in zone x [Mton/TWh];
CI_y the mean carbon intensity in the ZER scenario in zone y [Mton/TWh].
Taking the difference in transmission (aggregated value over the year) for a certain connection between the ZER and EUA case and multiplying this value with the difference of the CO_2 emission intensity yields an estimate of the cross border abatement between these zones. Note that using the emission intensity of the ZER scenarios is justified, since the difference of this parameter between zones is much larger than the difference between the ZER and EUA cases (see Figure 23).

Union has been used. This model captures much, but not all, of the highly complex operation of any electricity generation system by reflecting the capacity, fuel use, and technology of every generating plant in the system and by resolving dispatch to meet demand on an hourly basis. To simulate the conditions that existed in 2005 and 2006, the model is constrained to meet actual demand by zone for each hour given the capacity in place for that year and the daily fuel prices that existed for these years. Estimates of abatement are formed by taking the difference between runs that incorporate the actual daily CO_2 prices that these generating units faced and a hypothetical counterfactual in which there is no CO_2 price.

A distinctive feature of this paper compared to earlier simulations (Delarue et al., 2008) is the calibration of model results to actual generation shares as they were observed in the two years prior to the introduction of a CO_2 price in Europe. This calibration has a significant effect on estimates of abatement in that coal plants were not dispatched as much as the model predicted in the calibration years of 2003 and 2004, which suggests that the availability of existing coal plants is not as great as assumed in the model. This could reflect non-fuel price conditions that are unique to the calibration years, but also and more probably other limitations that are continued into the simulation period and that reflect plant idiosyncrasies or regulatory or network constraints that limit the use of these plants. Since the observed limitation on coal use implies greater use of natural gas and oil-fired generating units and less available capacity for switching, the resulting estimates of abatement in response to a CO_2 price are reduced by almost half.

The specific estimates for abatement in response to the EU ETS in 2005 and 2006 are 54 million tons in the calibrated version of the model and 99 million tons in the standard, non-calibrated version. These can be viewed as lower and upper bounds to the amount of abatement with more weight being given to the lower bound estimate. In both years and in both versions, approximately two-thirds of the estimated abatement occurred in 2005 due to the more favorable fuel and EUA price conditions. Both versions of the model agree that most of the abatement occurs in the UK and Germany where a significant reliance on coal is coupled with available natural gas generating capacity. Finally, most of the abatement occurs through fuel switching within each zone, although a noticeable increase in inter-zonal power transfers from lower emitting generation in France at the expense of higher emitting generation in Germany and Poland can be observed.

Two more general conclusions emerge from this research. First, as shown in the discussion of the topography of abatement, the relationship between CO_2 price and abatement is highly complex. For any given hour with given load and fuel prices, the expected monotonically rising relationship between price and abatement can be observed. However, when the hours are aggregated into days, weeks, months, and years, the constancy of the relationship is completely lost. Whatever the aggregation, the amount of abatement will depend as much upon load and fuel price relationships as it will upon the price of CO_2. Standard patterns or averages for any given time aggregation can be constructed, as we have done to illustrate these points, but these constructions will mimic any actual set of conditions only accidentally. At most, they will show what can be surmised from theory: all else being equal, a higher price will result in more abatement.

A second general conclusion concerns the longer term implications. The highly variable amount of abatement that results from any given CO_2 price in the analysis in this paper is conditioned on existing capacity. One obvious longer term implication is that a larger amount of available gas capacity will increase the amount of abatement at some CO_2 price so long as there is continuing coal-fired generation. While the analysis presented here also presents a cautionary warning that, even with a price on carbon, the price of natural gas relative to that of coal can reach levels that would make switching unattractive, the pronounced variations in load over daily, weekly, and seasonal cycles will likely lead to increased switching if the gas capacity is available. Whether the investment would be justified given expected fuel and CO_2 prices over the life of the intended investment, is the very essence of any investment decision. The analysis in this paper demonstrates that this decision must take into account the highly complex relationships between load, fuel and EUA prices in judging whether the expected utilization of any new plant will warrant the investment.

VI. Acknowledgement

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VIII. APPENDIX ON DATA AND SOURCES

A large amount of historic data is available from different sources, and a significant range on certain numbers could exist, due to a slight difference in the exact definition (e.g., the voltage level at which supply or demand is measured). In this work, an attempt is made to rely as much as possible on a coherent data set, resulting from a limited number of different sources. For the time dependent data (everything except power plant characteristics), data is gathered for the years 2003, 2004, 2005 and 2006.

1. Technical characteristics of power plants

Power plant characteristics consist of various numbers for each type of power plant: minimum operating point (as a percentage of the nominal capacity), the heat rate curve, i.e., the plant's efficiency at partial load (again described in percentages of the nominal capacity and efficiency), minimum up- and downtime, generalized availability and planned outage duration. Typical power plant characteristics result from various historic numbers, provided for by several power plant utilities.

2. Power system

The electricity generation systems of all the countries modeled are based upon the EURPROG 2006 report of Eurelectric (2007). Given the electricity generating capacity for each country and year per fuel and per type, together with the amount of CHP installed per fuel, an accurate representation of each power system can be created on power plant level that matches the amount of installed capacity by fuel as well as the installed amount per technology. Historic data is available for both the years 2003 and 2004, while for 2005 and 2006 the commissioning capacity is given.

3. Load

For the UCTE countries modeled (i.e., AT, BE, CH, CZ, DE, ES, FR, HU, IT, LU, NL, PL, PT, SL, SK), hourly load data for 2006 is taken from the UCTE website (UCTE, 2007). For the other years, these profiles are scaled to match both total and peak demand. This total electricity consumption and peak load is also taken from UCTE (2007). The load of Denmark, Finland, Sweden and Norway is taken from Energinet.dk (2007), Fingrid Oyj (2007), and Statnett (2007) respectively. The load of the United Kingdom and the Republic of Ireland is provided for by National Grid (2007) and Soni (2007), and Eirgrid (2007), respectively. Also for the non-UCTE countries, for the years where no hourly load is available, the profile of the closest year or of a similar country is scaled to preserve both total load and peak demand.

4. Net Transfer Capacities

For all the years modeled (2003-2006), appropriate NTC values are taken from ETSO (2007).

5. Fuel and EUA prices

The following fuel and carbon prices have been used, on a daily basis:

- Coal: API#2 coal (McCloskey index for coal), first month;
- Natural gas: NBP UK gas (National Balancing Point), day ahead;
- Oil: ICE gasoil (Intern Continental Exchange), front month;
- EUA: Powernext CO_2.

For the other fuels (e.g. nuclear, lignite) a reasonable estimate is made.

6. Historic generation and emissions data, and cross border flows

Historic generation data can be split up in a part that is taken into account in the model as input, and a part that is used for calibrating the model. The former consists of the following data, collected for the years 2003-2006, per zone, per fuel: the amount of nuclear generation, electricity from renewables (hydro, wind, biomass, photovoltaics and geothermal) and electricity from waste. This data is taken for the years 2003 and 2004 from Eurelectric's EURPROG 2006 report. For the years 2005 and 2006 this data was gathered from diverse sources: UCTE (2007), Energinet.dk (2007), Statistics Finland (2007), Statistics Sweden (2007), Statistics Norway (2007), BERR (2007).

The second part of historic data is the one used for calibrating the model, i.e., the electricity generation from fossil fuels. In this case, only the years 2003 and 2004 are considered. The numbers for these years are taken from Eurelectric (2007).

Historic emission data and cross border flows for the years 2003 and 2004 are used to qualitatively position the calibrated model. Emissions again result from Eurelectric (2007), while the cross border flows are taken from UCTE (2007).