Introduction of CO_2 Emission Certificates in a Simplified Model of the Benelux Electricity Network with Small and Large Consumers

Andreas Ehrenmann*, Giorgia Oggioni†, Ina Rumiantseva‡, Yves Smeers§

September, 2006

Louvain-la-Neuve/ Dresden

Abstract

This paper addresses a problem arising from the combination of the restructuring of the European electricity sector, the introduction of the EU Emission Trading System (EU-ETS) and the raising price of natural gas. Electricity intensive industrial consumers are currently facing a high price of electricity, which endangers their competitiveness and may force them to leave Europe. This would be a serious loss of welfare for European countries with possibly no environmental gain if these industries go and emit CO2 elsewhere.

We first consider a perfectly competition model where electricity prices are identical for all consumers and based on the short run marginal costs. A model extension with CO_2 emission certificates reveals rising electricity prices and a loss of industrial demand of about 25%. In this paper, we explore the possibility of developing special contracts, compatible with the principle of non-discrimination that would limit the impact of high gas prices and CO_2 prices on electricity large consumers. Electricity intensive consumers are in a position to finance the construction and operation of large generation units even if, for reasons of specialization of work, they would outsource their operations. We therefore consider an alternative organization whereby electricity intensive industrial consumers pay a price corresponding to the full cost of base load plants. Furthermore, we explore the possibility of allocation of allowances to industrial consumers that are normally given to generators when they invest in these plants.

We conduct a sample analysis on a prototype problem that is meant to represent Northwestern Europe. The model is formulated as a complementarity problem, coded in GAMS and solved with PATH.

---

* Electrabel, Strategy R&D, Belgium.

† University of Bergamo, Italy and CORE (Center for Operations Research and Econometrics), Université Catholique de Louvain, Belgium

‡ Dresden University of Technology, Chair for Energy Economics and Public Sector Management (EE2), Germany.

§ Tractabel Professor of Energy Economics, Department of Mathematical Engineering and Center for Operations Research and Econometrics (CORE), Université Catholique de Louvain, Belgium

1 Purpose of the Case Study

The present case study considers problems arising from the restructuring of the European electricity sector in combination with the introduction of the EU-ETS. Large industrial consumers are currently facing a high price of electricity and are threatening to leave Europe. This could be a serious loss of welfare for European countries, possibly with no environmental gain if these industries go and emit CO_2 elsewhere. Large industrial users of electricity invoke several reasons to leave. Among them, they complain that the high price of electricity is due to the exercise of market power by generation companies and to the pass through in electricity prices of the value of CO_2 allowances that they partially received free. As a result, these consumers request either special contracts whereby they can procure electricity at a lower price (capacity splitting or average pricing), or special regulation that would prevent generators to pass the price of v certificates in the marginal cost of electricity.

The objective of the case study is to discuss these questions with small market simulation models. The applied model presents the simplified Benelux electricity network with seven nodes, whereby aggregating Germany and France into one aggregated node each. In a first step, we explore the current situation and the impact of the introduction of emission certificates. Assuming perfect competition, the following questions should be answered:

- Which nodal prices occur when introducing emission certificates?
- What is the price increase seen by consumers as a result of the introduction of the ETS?
- In how far does the demand of large consumers change?
- How is welfare affected?

In a second step, we model the impact of several political measures to account for to the needs of large customers. In particular, we consider these options:

1. Allocation of emission allowances to industrial customers (section 3.1): Industrial consumers receive a certain amount of emission allowances for free. They can be charged for emissions only at levels above their allowances.

2. Average pricing (section 3.2): Large customers participate in the construction and operation of own base load plants. They pay average instead of marginal prices for this energy.

For those measures, we will discuss the same questions as for the base case to compare the political options.

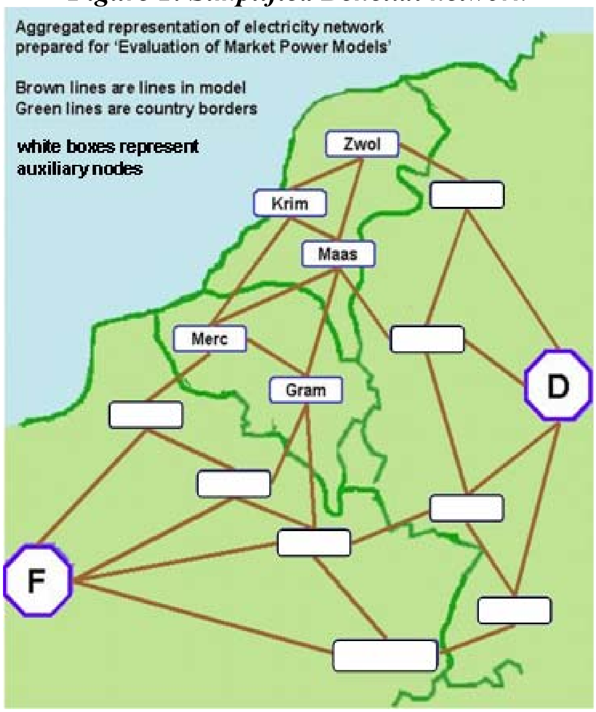
2 Modeling the impact of CO_2 certificates

2.1 Assumptions[1]

The present analysis is applied to a prototype market of Northwest Europe (Benelux) with seven nodes, and 28 high-voltage transmission lines, 20 of which – the inner Benelux lines - are limited in their transmission capacity. Electricity is provided by eight generators: E.ON Energie AG, Electrabel SA, Electricité de France, ENBW Energieversorgung Baden-Württemberg, Essent Energie Productie BV, Nuon, RWE Energie AG, Vattenfall Europe AG. A ninth generator, called "fringe" presents the remaining small generators. Each generator runs several power plants with limited generation capacities at different nodes. We use staircase marginal cost curves to represent supply functions per generator and node (Table 5). For the generator's behaviour we assume, for simplicity, perfect competition.

The network consists of 15 nodes in four countries, which are connected by 28 lines with limited capacity and is represented by the PTDF matrix. Ten of these lines are trans-border lines that connect Germany to the Netherlands (2 lines), the Netherlands to Belgium (3), Belgium to France (3) and France to Germany (2). Supply and demand are located at seven nodes in Belgium ('Merchtem', 'Gramme') and the Netherlands ('Krimpen', 'Maastricht', 'Zwolle'), but only at the aggregated nodes 'D' and 'F' in Germany and France. The remaining German and French nodes are passive nodes (Figure 1).

Figure 1: Simplified Benelux network



Source: ECN, 2003. Own modification.

[1] All input data is listed in Appendix II.

We consider two periods: off-peak and peak, which differ in their duration measured in hours per year over the nodes in accordance with real load duration curves. The model contains two consumer groups, small and electricity-intensive industrial (large) users. Their demand functions are assumed to be linear and differing over nodes (Table 6). The functions are based on a reference price of 40 €/MWh in off-peak and 45 €/MWh in peak times. Small consumers are expected to behave relatively inflexible in case of price changes, so we assume an elasticity of -0.1 in the reference points. Large consumers are assumed to be highly mobile in the long run: they might leave Europe in case of high electricity prices and produce elsewhere. So, their long-run reference demand elasticity was set -1.

2.2 Basic case: market without emission certificates

The basic case simulates the situation without emission certificates and gives the reference results. Here, we assume no market splitting, so there is only one market clearing price. The model is based on the nodal price approach that explicitly takes into account the network characteristics. Further models are modifications of the basic case, which will be described below. All models are formulated as mixed complementarity problems (MCP) in GAMS and solved with PATH.

The objective function is the profit maximization of the competitive (price-taking) generators which is subject to several constraints as the generation capacity constraints, the transmission capacity constraints, and the market balance. The KKT conditions for the basic case are[2]:

$$0 \le -P_{t,c,i} + \eta_{t,c,i} \perp g_{t,c,i} \ge 0 \qquad (1.$$

$$0 \le g_{t,c,i} - \sum_{j,p} g_{t,c,j,i,p} \perp \eta_{t,c,i} \ge 0 \qquad (2.$$

$$0 \le c_{j,i,p} + v_{t,j,i,p} - \eta_{t,c,i} \perp g_{t,c,j,i,p} \ge 0 \qquad (3.$$

$$0 \le G_{j,i,p} - \sum_{c} g_{t,c,j,i,p} \perp v_{t,j,i,p} \ge 0 \qquad (4.$$

The nodal price $P_{t,c,i}$ equals $\eta_{t,c,i}$ (1, which is the shadow variable of the energy balance (2. If the equality of both variables is true (left hand part yields zero), then we obtain a positive generation $g_{t,c,i}$. Condition (3 includes $\eta_{t,c,i}$, the marginal costs of generation and the scarcity price of capacity $v_{t,j,i,p}$, which is the complementarity variable of inequality (4.

$$0 \le P_{t,c,i} - a_{t,c,i} + b_{t,c,i} * d_{t,c,i} \perp d_{t,c,i} \ge 0 \qquad (5.$$

Inequality (5 ensures that the nodal price equals the price for the given demand according to the demand function and yields the nodal demand $d_{t,c,i}$.

---

2 For the model's nomenclature see Appendix I.

$$0 \leq \sum_i g_{t,c,i} - \sum_i d_{t,c,i} \perp \tilde{P}_{t,c} \geq 0 \qquad (6.$$

The market balance constraint (6 gives the price at the hub $\widetilde{P}_{t,c}$.

$$0 \leq T_m - \sum_i \left(\Gamma_{m,i} * \sum_c \left(g_{t,c,i} - d_{t,c,i} \right) \right) \perp \mu^+_{t,m} \geq 0 \qquad (7.$$

$$0 \leq T_m + \sum_i \left(\Gamma_{m,i} * \sum_c \left(g_{t,c,i} - d_{t,c,i} \right) \right) \perp \mu^-_{t,m} \geq 0 \qquad (8.$$

Inequalities (7 and (8 describe the network constraints in accordance with the PTDF matrix $\Gamma_{m,i}$: the net power flow $g_{t,c,i}$-$d_{t,,c,,i}$ (difference between the total quantity supplied and demanded at each node) has to be lower than the grid's capacity T_m. Depending on the direction of flow the inequalities yield the scarcity prices on transmission $\mu^+_{t,m}$ and $\mu^-_{t,m}$. Inequality (9 refers to the nodal prices, which are the sum of the price at the hub and the transmission premium. Without congestion, the prices would be equal at all nodes.

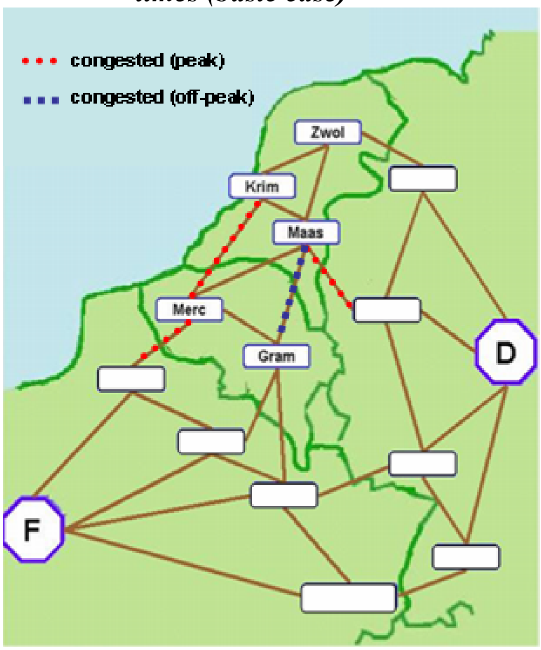
$$0 \leq P_{t,c,i} - \tilde{P}_{t,c} - \sum_m \left(\left(\mu^-_{t,m} - \mu^+_{t,m} \right) * \Gamma_{m,i} \right) \perp P_{t,c,i} \geq 0 \qquad (9.$$

The results reveal off-peak prices of about 31 €/MWh in Germany and France and about 35 €/MWh for the Belgian and Dutch nodes.[3] At peak times, prices reach 51.68 to 51.96 €/MWh.

Table 1: Nodal prices [€/MWh] in the basic case without emissions

	Germany	France	
off-peak	31.78	30.93	
peak	51.70	51.78	
Belgium	*Merchtem*	*Gramme*	
off-peak	35.62	34.15	
peak	51.96	51.79	
Netherlands	*Krimpen*	*Maastricht*	*Zwolle*
off-peak	35.62	35.62	34.23
peak	51.73	51.59	51.68

Figure 2: Congestion in peak and off-peak times (basic case)



[3] In this basic case, prices are the same for small and large customers.

The quasi uniform peak prices show, that there is almost no congestion in peak times. In off-peak times, France is a net exporter causing congestions at the border lines between Belgium and the Netherlands and Germany and the Netherlands (Figure 1). In peak times, however, France has to import electricity, because the demand of their small consumers is more than doubling and thus exceeding its own generation capacities. In result, only one line between the Netherlands and Belgium is congested.

2.3 Introduction of emissions

All European countries taking part in the ETS had to set up National Allocation Plans (NAPs) indicating the amount of CO_2 emission allowances that would be distributed among the emission producing firms. Therefore, emission caps were set up based on historical data and reduction aims. If the individual production of one firm exceeds its emission allowances, additional certificates have to be purchased on the market. The NAPs of the countries included into the model allow emissions of about 403 TWh p.a. The price λ of the certificates (in €/MWh) results as a shadow price from the additional emission constraint which has to be introduced into the model:

$$0 \leq E - \sum_{t,c,j,i,p} \left(\varepsilon_p * g_{t,c,j,i,p} * h_{t,i} \right) \perp \lambda \geq 0 \qquad (10.$$

The condition says that the total amount of electricity produced over the year (hourly generation times the hours of each period) must not exceed the annual emission cap *E*. If the emission constraint is binding, i.e. it is equal zero, the value of λ will be positive. Now, inequality (3 has to be modified, because the price determining $\eta_{t,c,i}$ must also include the costs for the emission certificates. Those depend on the plants' emission factors ε_p, which indicates the emissions in t CO_2/MWh for each generation technology:

$$0 \leq c_{j,i,p} + \nu_{t,j,i,p} + \varepsilon_p * \lambda - \eta_{t,c,i} \perp g_{t,c,j,i,p} \geq 0 \qquad (11.$$

After the introduction of emissions, electricity prices generally increase over all nodes while demand, consequently, decreases. In particular, nodal prices are about 36.5% higher in off-peak times compared to the basic case. In peak times, however, the nodes face only relatively small price increases of about 0.3% to 11.1% only (Figure 3). In absence of emission trading, CCGT and oil-based plants set electricity prices for both small and large consumers respectively in off-peak and peak periods. Now, after the introduction of the ETS, gas-based combined cycle turbines are the marginal generating units in the market in *both* periods, because it is even in peak times not profitable anymore to run emission-extensive, and thus even more expensive, oil-based plants. This explains the slight price increase in peak times.

Figure 3: ***Off-peak (left) and peak (right) nodal prices [€/MWh] before and after the introduction of emission trading***

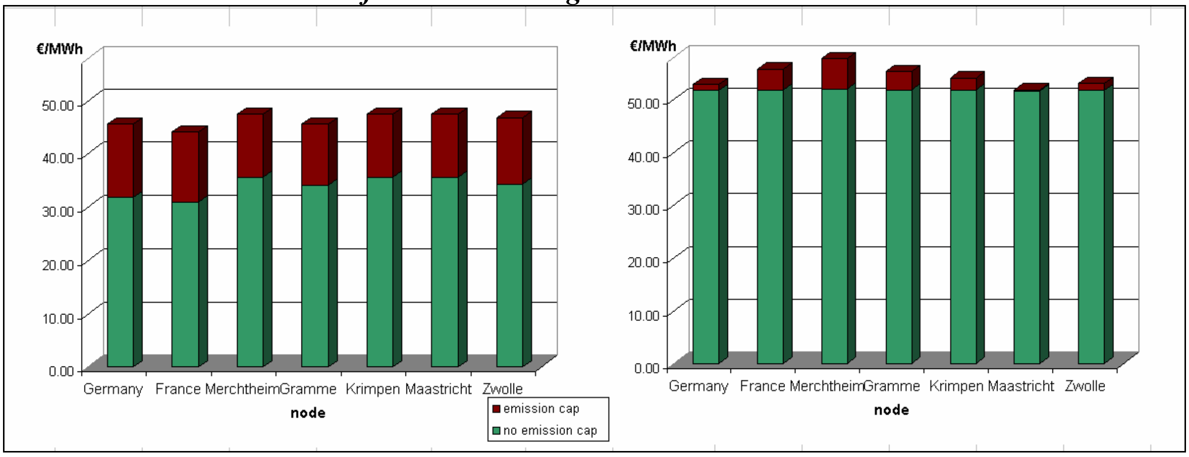
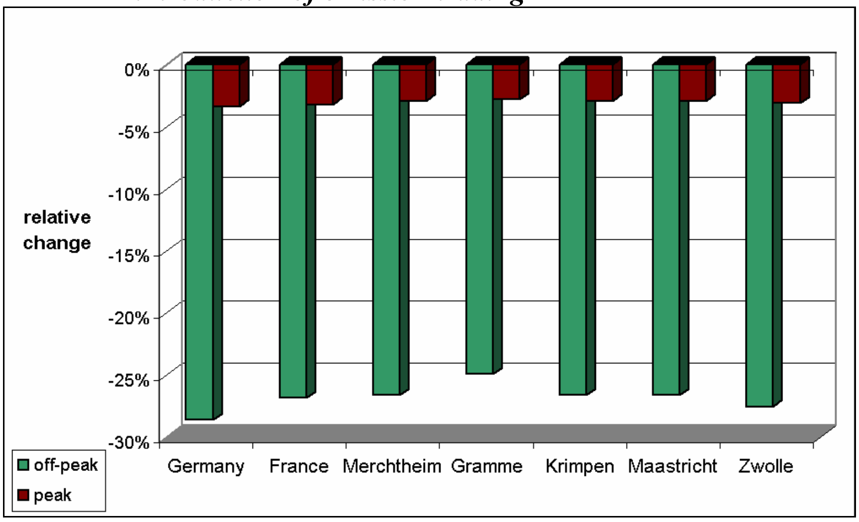


Figure 4: ***Relative change of annual demand of large customers after the introduction of emission trading***



The severe price increase in off-peak times causes a reduction in hourly industry demand of more than 25% at all nodes (Figure 4). Over the year, this sums up to a loss of 162 TWh. In practice, this would mean that up to one fourth of the firms might consider leaving Europe due to the price increases after the introduction of emissions.

2.4 Increasing gas prices

In times of increasing fuel prices one would expect rising electricity prices as well. This might lead to a growing burden for consumers – beside the additional costs from the emission trading. Therefore, we tested results for different gas price scenarios (120%, 150% and 200% of present prices) in the model with emission trading. Except for 'Maastricht', we observe little changes or even decreases in electricity prices in off-peak times, because gas is rather seldom used. In the case of higher prices gas will be partly replaced by less expensive fuels. So the system marginal price can even fall ('Germany', 'France', 'Gramme'). In peak times, however, there are serious price increases, especially in the Belgian and Dutch nodes (Figure 5). Large consumers' annual demand would – compared to the scenario with recent gas prices and depending on the gas price scenario -

decrease by 10.7 TWh (120%), 35.8 TWh (150%) or 55.3 TWh (200%). With the increase of gas prices, generating companies base their production on less pollutant technologies (Figure 6). Emission certificate prices, consequently, decrease (Figure 7).

Figure 5: Nodal Prices [€/MWh] for different gas prices scenarios in off-peak (left) and peak (right) times

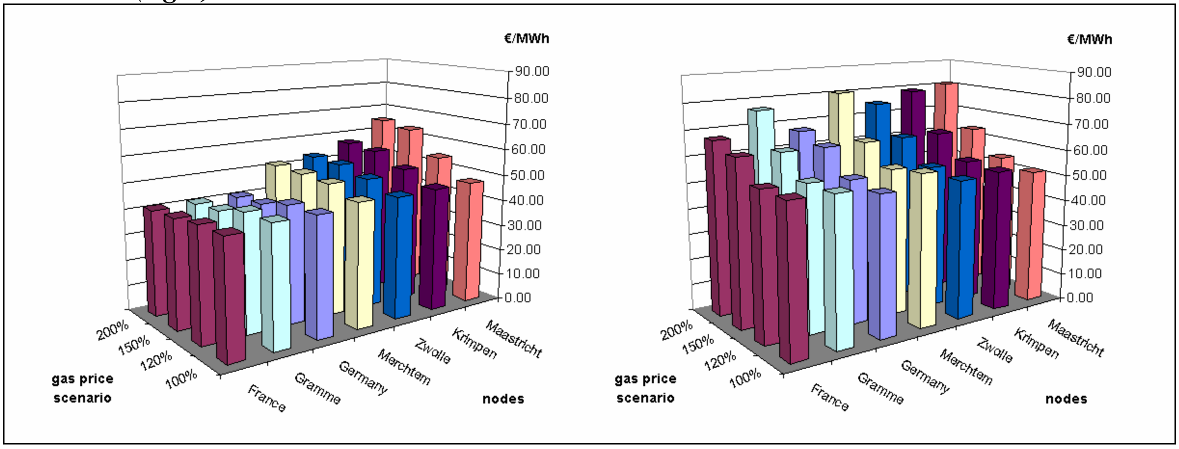


Figure 6: Annual generation per technology for large consumers for different gas price scenarios

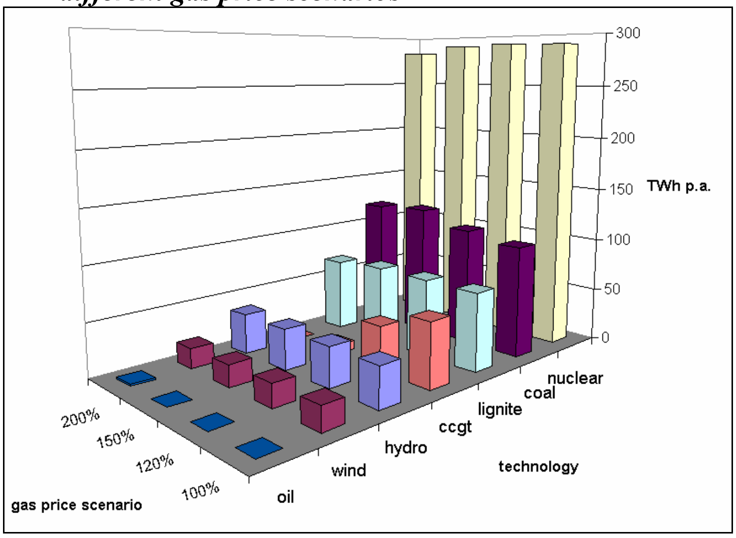
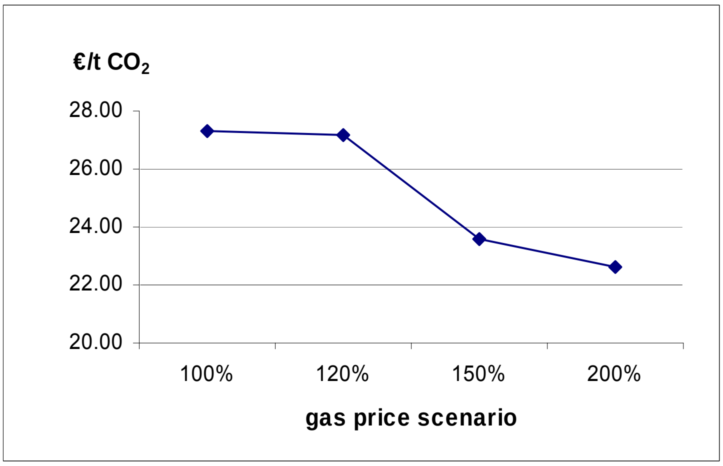


Figure 7: Emission certificate prices [€/t CO2] for different gas prices scenarios



3 Modeling political measures to accompany large customers

The following sections explore different measures to attenuate the negative consequences of the ETS for large customers. The aim is to find solutions whereby industrial consumers would be (partly) relieved from the additional burdens from the ETS. Thus, the prices they face should be lower than in the case after the introduction of emission trading (but not higher than in the initial case). This should lead to a less severe loss in industrial demand. Small consumers might face in those cases higher prices than after the introduction of the ETS. However, the options should also ensure that prices increases were moderate in this market segment. Thus, all approaches have to be compared with the initial scenario including an emission cap. The according models simulate a market with two different segments -'large' and 'small' customers- where prices are determined separately for both groups.

3.1 Free emission allowances for industrial consumers

A first approach to limit the effects of emission certificates on industrial consumers is to give them free emission allowances for the demanded electricity. The industry receives a share of the total emission allowances which equals the shares in emission production in the basic case before the introduction of emission trading (Table 8).

Equations and inequalities (1, (2, (11, (5, and (6 now occur per market segment, i.e. twice., while (4, (7, (8, and (10 remain common constraints to the market. Inequality (9 is still effective for the small consumers, but has to be modified for industrial consumers as following:

$$\begin{aligned}0 \leq\ & P_{t,i}^{\text{large}} - \tilde{P}_t^{\text{large}} \\ & - \sum_m \left(\left(\mu_{t,m}^- - \mu_{t,m}^+ \right) * \Gamma_{m,i} \right) \\ & + \lambda \frac{E_i^{\text{large}}}{\sum_t (d_{t,i}^{\text{large}} \cdot h_{t,i})} \qquad \perp P_{t,i}^{\text{large}} \geq 0\end{aligned} \tag{12.}$$

The last term concerning emission expresses that the price for large customers is reduced by the amount of annual allowances in relation to their annual consumption at the certificate price λ.[8]

Under this assumption, nodal peak prices for large consumers mainly change in 'Gramme', 'Krimpen' and 'Maastricht' with decreases of 15% to 28% in off-peak and 3% to 18% in peak times. Small consumers face moderate increases in prices of up to 10% in peak times, while there

---

[8] One has to consider the dimension of the variables:

$$\lambda\left[€/t\,CO_2\right] \cdot \frac{E_i^{\text{large}}\left[t\ CO_2\ p.a.\right]}{\sum_t (d_{t,i}^{\text{large}} \cdot h_{t,i})\left[MWh\ p.a.\right]}$$

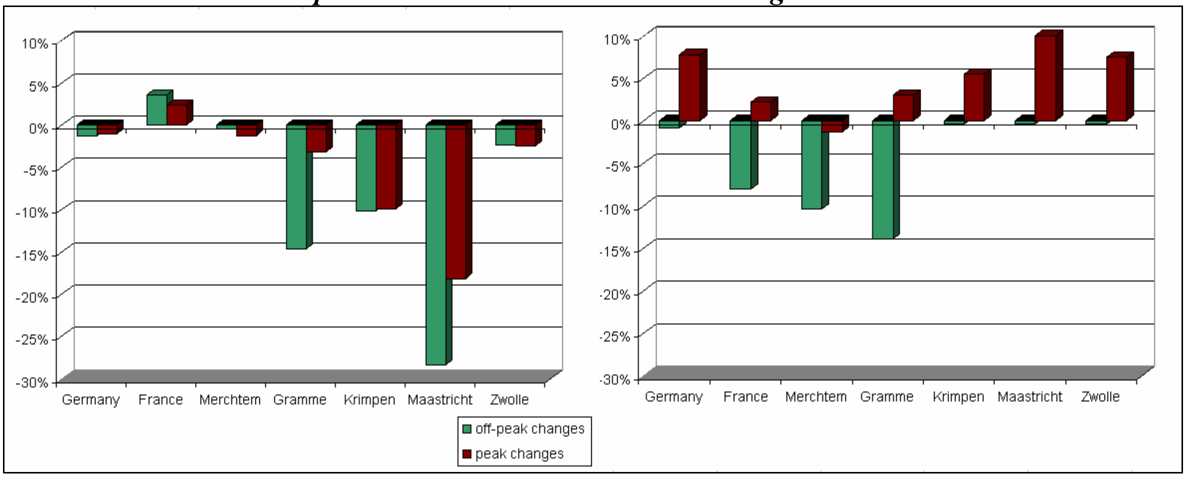
Altogether, this gives the €/MWh that large consumers have *not* to pay for emissions. They have a fixed amount of allowances in the beginning of the year ($E_i^{\text{large}}\left[t\ CO_2\ p.a.\right]$). The less they will consume in a year ($\sum_t (d_{t,i}^{\text{large}} \cdot h_{t,i})\left[MWh\ p.a.\right]$), the more €/MWh they can save.

are lower prices (up to -14%) in ‘France’, ‘Merchtem’ and ‘Gramme’ in off-peak times (Table 2 and Figure 8). The small consumer prices show that there is no congestion in peak times. The differences of large consumers’ peak prices result from the fact, that the emission allowance “bonus” (which differs over nodes) is subtracted from the hub price. As France has – due to its generation structure – relatively few allowances, it cannot compensate for the higher hub price and faces somewhat increased prices (2-4%). The loss in electricity demand of the industry (168 TWh p.a.) could be slightly reduced compared to the loss after the introduction of the ETS (173 TWh p.a.). The certificate price is with 26.89 €/t CO_2 almost the same as before (27.31 €/t CO_2).

Table 2: Nodal prices [€/MWh] in the case of free emission allowances for large customers

		Germany	France	Merchtem	Gramme	Krimpen	Maastricht	Zwolle
small consumers	off-peak	45.17	40.52	42.47	39.22	47.24	47.24	46.63
	peak	56.94	56.94	56.94	56.94	56.94	56.94	56.94
large consumers	off-peak	45.17	45.17	47.24	40.54	43.79	37.32	46.03
	peak	52.30	56.94	57.06	53.62	48.85	42.38	51.69

Figure 8: Free Allowances: Relative change of nodal prices for large (left) and small (right) customers compared to the case with emission trading



3.2 Average pricing for the large customers

Electricity intensive consumers are in a position to finance the construction and operation of large generation units. We therefore consider an alternative organization whereby electricity intensive industrial consumers pay a price corresponding to the full (fixed and variable) cost of base load plants plus the marginal costs of the rest of the plants generating for large consumers. The full costs of a plant’s generation include a fixed and a variable cost part. The fixed costs are calculated from average construction costs of a plant type in each of the countries, assuming a plant’s life time of 30 years and an interest rate of 10%:

$$f = \frac{r \cdot C}{1 - \frac{1}{(1+r)^{l}}} \qquad (13.$$

The common model constraints (7, (8 and (10 can be maintained in this model. For the small consumers we keep inequalities (1, (2, (5, (6, and (9. Depending on the generation structure of each node we dedicate a certain share of base load capacities to industrial consumers (Table 3). Now, there are two kinds of capacities ('types').[9] Thus, inequality (4 has to be included into the model for both market segments and both types of capacities. Furthermore, one obtains different capacity premiums *v* for the plants depending on their type. Inequality (11 now occurs twice for small consumers.

$$0 \le \overline{c}_{j,i,\overline{p}} + \overline{v}_{t,j,i,\overline{p}} + \overline{\varepsilon}_{\overline{p}}\lambda - \eta^{small}_{t,c,i} \perp g^{small}_{t,j,i,\overline{p}} \ge 0 \qquad (14.$$

$$0 \le \hat{c}_{j,i,\hat{p}} + \hat{v}^{small}_{t,j,i,\hat{p}} + \hat{\varepsilon}_{\hat{p}}\lambda - \eta^{small}_{t,c,i} \perp g^{small}_{t,j,i,\hat{p}} \ge 0 \qquad (15.$$

The resulting dual variables of inequalities (14 and (15 sum up to the generation for small consumers over periods, firms, nodes and plant types. For large consumers, we maintain merely inequality (4 and the market balance (6, whereby we change the resulting dual variable for the latter to α_i. It is used (comparable to the hub price) to determine further variables:

$$0 \le \sum_{j,t,p} g^{large}_{t,j,i,p} - \sum_{t} d^{large}_{t,i} \perp \alpha_i \ge 0 \qquad (16.$$

The remaining inequalities have to be modified. We obtain:

$$0 \le -\alpha_i + \overline{c}_{j,i,\overline{p}} + \overline{v}_{t,j,i,\overline{p}} + \overline{\varepsilon}_{\overline{p}}\lambda - \sum_{m}\left(\Gamma_{m,i}\left(-\mu^{+}_{t,m} + \mu^{-}_{t,m}\right)\right) \perp g^{large}_{t,j,i,\overline{p}} \ge 0 \qquad (17.$$

$$0 \le -\alpha_i + \hat{c}_{j,i,\hat{p}} + \hat{v}^{large}_{t,j,i,\hat{p}} + \hat{\varepsilon}_{\hat{p}}\lambda - \sum_{m}\left(\Gamma_{m,i}\left(-\mu^{+}_{t,m} + \mu^{-}_{t,m}\right)\right) \perp g^{large}_{t,j,i,\hat{p}} \ge 0 \qquad (18.$$

In this model, large customers pay for the energy from their dedicated plants an average price P^*_i (see equation (20) and *not* the marginal cost based price. P^*_i times the industry's demand should equal

1. the inverse demand function times industry's demand (see inequality (5):

$$0 \le P^*_i \cdot d^{large}_{t,i} - a^{large}_{t,i} \cdot d^{large}_{t,i} + b^{large}_{t,i} \cdot d^{large}_{t,i} \cdot d^{large}_{t,i} \perp d^{large}_{t,i} \ge 0 \qquad (19.$$

and

2. all expenses on the energy generated for it, including pro-rata fixed costs $\hat{f}$ for the dedicated capacities:

[9] The corresponding variables of dedicated base-load capacities are denoted in the model with a hat: '^', the rest with a cross: '¯'.

$$\sum_t P_i^* \cdot d_{t,i}^{large} = \sum_{t,j,p} \left(g_{t,j,i,p}^{large} \left(c_{t,j,i,p} + \varepsilon_p \lambda + \right) \right) + \sum_{\hat{p}} \hat{f}_{\hat{p},i} - \sum_{t,m} \left(\Gamma_{m,i} \cdot n_{t,i} \cdot \mu_{t,m}^{+} \right) + \sum_{t,m} \left(\Gamma_{m,i} \cdot n_{t,i} \cdot \mu_{t,m}^{-} \right) \quad (20.$$

Equation (20 is matched with the nodal average price P_i^* in order to make the problem square. The last part of the equation adjusts the expenses by the transmission premium times the net injections n in a node, which are calculated as follows:

$$n_{t,i} = \sum_{j,p} \left(g_{t,c,j,i,p} - d_{t,c,i} \right) \quad (21.$$

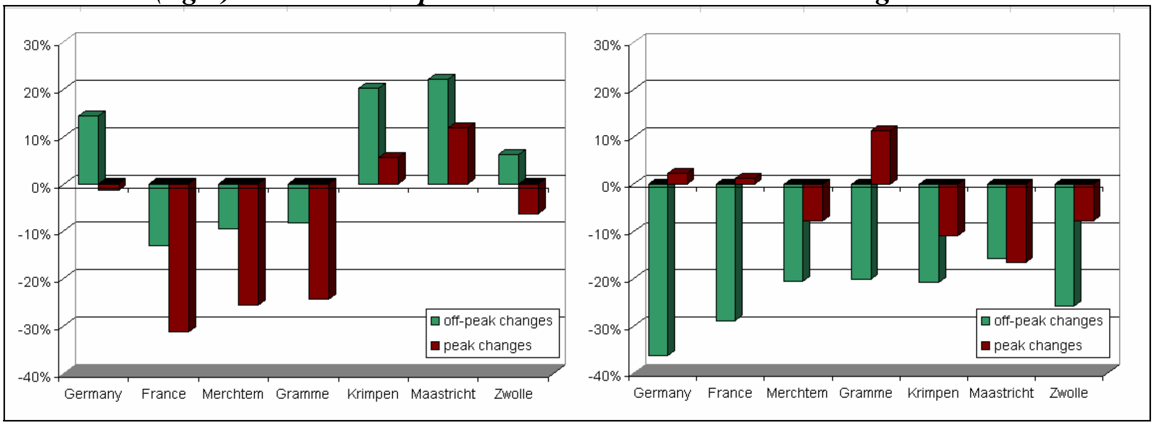
Results of this model are little encouraging: For an exemplary base-load capacity splitting we see huge price increases for large consumers compared to the off-peak prices before the ETS introduction (Table 3). In peak times, there are decreases up to -26% in France and Belgium, while prices remain more or less unchanged for large consumers in the other nodes. Small consumers (with a different benchmark case!) profit from price decreases in peak times (except 'Gramme') and even more in off peak times with up to -36% (Figure 9). The loss in industry's demand is considerably higher than after the introduction of emission trading (-249 TWh p.a. vs. -173 TWh p.a.). The emission certificate price was reduced by two thirds to 9.93 €/MWh.

Table 3: Shares in dedicated capacity, nodal prices for small consumers and average prices for industrial consumers [€/MWh]

		Germany	France	Belgium	
				Merchtem	**Gramme**
dedicated shares in capacity for *large* customers	nuclear	1	0.6	0.8	0.8
	lignite	0.9			
	coal			0.7	0.9
nodal prices for small customers	off-peak	28.98	31.35	37.67	36.39
	peak	54.01	56.38	53.24	61.42
average prices for large customers		52.09	38.35	42.96	41.80

		Netherlands		
		Krimpen	**Maastricht**	**Zwolle**
dedicated shares in capacity for *large* customers	nuclear	1		
	lignite			
	coal	1		1
nodal prices for small customers	off-peak	37.55	39.91	34.75
	peak	48.12	43.11	48.85
average prices for large customers		57.02	57.90	49.68

Figure 9: Average Pricing: Relative changes of nodal prices for large (left) and small (right) customers compared to the case with emission trading



4 Implications and conclusion

The introduction of the ETS leads to a significant increase in prices and a severe loss in industrial demand. In the modeled competitive Northwestern European market with marginal cost pricing, emission certificates would cost 27.31 €/t CO2 (Table 4). Prices would mainly rise in off-peak-times, while peak prices are less affected from the emission trading. This paper explored two possible options to compensate industrial consumers for the negative consequences of the ETS. If they were given demand-based gratuitous allowances, prices for industrial consumers would sink in both peak and off-peak times. This would lead to a slightly higher total demand of large consumers (583 instead of 582 TWh p.a.). Yet, compared to the initial case without emission trading (744 TWh p.a.), this improvement is insignificant. Alternatively, industrial consumers might finance a part of base-load generation capacities and, therefore, would be guaranteed to be supplied by these plants. Results of this model showed that this approach is – under the given assumptions – not applicable: although mean peak prices could be reduced for large customers, the increase during off-peak times leads to significantly lower industrial electricity demand (497 TWh p.a.). Also, welfare is lowest for the average pricing approach compared with all other cases.

Table 4: Overview of results of the models

Pricing approach	*ETS*	*Allowances for industrial cons.*	**welfare [Mio. €]**	**λ [€/t CO2]**	**mean off-peak nodal price [€/MWh]** *small*	**mean off-peak nodal price [€/MWh]** *large*	**mean peak nodal price [€/MWh]** *small*	**mean peak nodal price [€/MWh]** *large*
Marginal cost pricing	no	-	47.0	-	33.99	33.99	51.75	51.75
	yes	no	46.5	27.31	46.33	46.33	54.32	54.32
	yes	demand-based	46.9	26.89	44.07	43.61	56.94	51.83
Average pricing	yes	no	44.2	9.93	35.23	48.54	52.16	48.54

Pricing approach	*ETS*	*Allowances for industrial cons.*	**annual payments [bill. €]** *small*	**annual payments [bill. €]** *large*	**annual payments [bill. €]** ∑	**annual demand [TWh]** *small*	**annual demand [TWh]** *large*	**annual demand [TWh]** ∑
Marginal cost pricing	no	-	25.01	27.71	52.72	594	744	1,338
	yes	no	29.02	27.93	56.95	583	582	1,165
	yes	demand-based	29.14	27.97	57.11	587	583	1,170
Average pricing	yes	no	25.70	23.17	48.87	592	497	1,089

This apparently strange result derives from the fact that, in our runs, large industrial consumers pay plant fixed costs in the special contract, while short-run marginal cost pricing embeds a scarcity rent that, given our data, is lower than fixed costs. However, it is not clear from the theory if the large consumers would effectively benefit from these special contracts in the case the generation system were allowed to develop competitively.

The interpretation of the model's results is partially restricted by the model itself and the input data: on the one hand, one does not obtain feasible solutions only for certain distributions of allowances and base-load capacities to large customers. It is difficult to say whether this is due to the solver capabilities of GAMS or the model structure. On the other hand, we had to make a series of assumptions according input data. Despite an intense data research there are still obscurities about central inputs. Results might change notably for different and more detailed input data. Also, we merely considered the possibility to replace existing capacities by industrial generation capacities and not to build additional plants, because the spectrum of possible options would be unlimited.

Beside these modifications of the presented approaches, they could be improved by certain extensions: in the average pricing approach industrial consumers could be given allowances according to the capacities they own. Finally, results would become more realistic under the assumption of oligopolistic competition in form of Cournot or conjectured supply function models.

References

ECN (2003): *Evaluation of models for market power in electricity networks Test data*. Retrieved December 2003 from: www.electricitymarkets.info/competes/modelcomp/testdata.html

EdF (2005a): *Annual Report*. Retrieved June 2006 from: http://www.edf.fr/html/ra_2005/uk/sustainable_dev.html

EdF (2005b): *2005 Document de Référence*. Retrieved June 2006 from: http://www.edf.fr/1i/Accueilfr.html

Electrabel (2005): *Annual Report*. Retrieved June 2006 from: http://www.electrabel.com/finance/annual_report/annualreport_en.asp

EnBW (2005): *Annual Report.* Retrieved June 2006 from: http://www.enbw.com/content/en/press/index.jsp;jsessionid=2A8043FCCC423A9F13D0406D9168A6AF.nbw04

Eon (2005a): *Annual Report*. Retrieved June 2006 from: http://www.eon.com/en/investoren/937.jsp

Eon (2005b): *Hydroelectric Power Technology*. Retrieved June 2006 from: http://www.eon.com/en/investoren/937.jsp

Eon (2006): *Wind Power in Germany.* Retrieved June 2006 from: http://www.eon.com/en/investoren/937.jsp.

Essent (2005a): Annual Report. Retrieved June 2006 from: http://www.essent-finance.nl/publications/publications.jsp

Essent (2005b): Deutsche Essent GmbH. Retrieved June 2006 from: http://www.essent-finance.nl/publications/publications.jsp.

European Commission (2004): Plan National Belge d'Allocation de quotas. Retrieved June 2006 from: http://www.climat.be/pdfs/Plan_allocation_Belge_fr.pdf

European Commission (2006), National Reports on Verified Emission and Surrendered Allowances. Retrieved April 2006 from: http://ec.europa.eu/environment/climat/emission/citl_en.htm

Eurostat (2004): Consumption of electricity by industry, transport activities and households/services. Retrieved June 2006 from: http://epp.eurostat.ec.europa.eu/portal/page?_pageid=1996,45323734&_dad=portal&_schema=PORTAL&screen=welcomeref&open=/&product=Yearlies_new_environment_energy&depth=4

IEA (2005): Projected Costs of Generating Electricity. International Energy Agency.

Nuon (2005): Annual Report. Retrieved July 2006 from: http://corporate.nuon.com/en/content.jsp

République Française (2005): La liste des installations concernées et leur quota (2005-2007). Journal officiel de la République Française. Retrieved July 2006 from: http://www.industrie.gouv.fr/energie/developp/serre/textes/pnaq.htm.

RWE (2005): Annual Report. Retrieved July 2006 from: http://www.rwe.com/generator.aspx/investorrelations/financial-reports/language=en/id=2324/financial-reports-page.html

RWE (2006): Fact & Figure. Retrieved July 2006 from: http://www.rwe.com/generator.aspx/investorrelations/financial-reports/language=en/id=2324/financial-reports-page.html

Stoft S., *Power System Economics*, IEEE/Wiley, 2002.

UCTE (2005a): National electricity consumption 2005 and peak load. Retrieved May 2006 from: http://www.ucte.org/statistics/consumption/e_default.asp

UTCE (2005b): Monthly Consumption of a specific country for a specific range of time. Retrieved May 2006 from: http://www.ucte.org/statistics/onlinedata/consumption/e_default.asp

Vattenfall (2005a): Annual Report. Retrieved June 2006 from: http://www3.vattenfall.com/annual_report_2005/filter.asp?filename=page_000.html

Vattenfall (2005b): Mining & Generation. Retrieved June 2006 from: http://www3.vattenfall.com/annual_report_2005/filter.asp?filename=page_000.html

Appendix I: Abbreviations and nomenclature in the model

ABBREVIATIONS

EU ETS	European Emission Trading System	*kWh*	kilowatt hours
		MWh	megawatt hours

MW megawatt

NAP National Allocation Plan

p.a. per annum

PTDF Power Transfer Distribution Factor (matrix describing the flows in a network when injecting 1 MW at one node)

TWh terawatt hours

INDICES

c market segments (customer group): large and small consumers

i active nodes

j electricity generating companies (firms)

m transmission lines

p plant type (technology)

t period (peak, off-peak)

VARIABLES AND PARAMETERS

$a_{t,c,i}$ intercept of the linear demand function per period, market segment and node (derived from reference points and reference elasticities) [€/MWh]

$b_{t,c,i}$ slope of the linear demand function of period t, market segment and node (derived from reference points and reference elasticities) [€/(MW)^{2}h]

C construction costs per kWh for a plant (overnight costs) [€/kWh]

$c_{j,i,p}$ marginal costs per firm, node and plant type [€/MWh]

$d_{t,c,i}$ hourly demand per period, market segment and node [MWh/h]=[MW]

E annual emission cap [MWh]

E_i^{large} annual allowances allocated to large customers per node [MWh]

$f_{p,i}$ pro-rata fixed costs per MWh per plant type and node (derived from overnight costs) [€/MWh]

$G_{j,i,p}$ generation capacities of the firms' power plants per node and technology [MW]

$g_{t,c,i}$ hourly generation per period, market segment and node [MWh/h]=[MW]

$g_{t,c,j,i,p}$ hourly generation per period, market segment, firm, node, and plant type [MWh/h]=[MW]

$h_{t,i}$ duration of the periods per node

l life time of a plant

$P_{t,c,i}$ nodal price per period and market segment [€/MWh]

$\tilde{P}_{t,c}$ price at the hub per period and market segment [€/MWh]

r interest rate

T_m capacities of the transmission lines [MW]

α_i dual variable from the capacity constraint of large consumers in the average pricing model

$\Gamma_{m,i}$ PTDF matrix

ε_p emission factors per technology

$\eta_{t,c,i}$ shadow variable of the energy balance

λ shadow price of the emission constraint (certificate price)

$\mu^{+}_{t,m}$, $\mu^{-}_{t,m}$ scarcity prices on transmission (depending on the direction of flows)

$\nu_{t,j,i,p}$ scarcity price of capacity per period, firm, node and plant type

The indices ^{small} and ^{large} indicate the corresponding variables for small and large customers.

The corresponding variables of dedicated lignite and nuclear capacities in the average pricing model are denoted with a hat: '^', the rest with a cross: '¯'.

Appendix II: Input Data

Table 5: Marginal costs, emission factors, and available capacities according to the main fuel or technology [MW]

	hydro[10]	**wind**	**nuclear**	**lignite**	**coal**	**ccgt**	**other gas**	**oil**
marginal costs	0	4.05	4.5	12.79-14.10*	19.51-21.05*	35.62-36.33*	54.92-55.20*	46.9
emission factor	0	0	0	0.97	0.9542	0.432	0.6266	0.8441
availability	*different*[11]	*25%*	*75%*	*85%*	*80%*	*85%*	*85%*	*85%*
Available capacity by firms								
	hydro	**wind**	**nuclear**	**lignite**	**coal**	**ccgt**	**other gas**	**oil**
E.on	427.7	20.15	6,228	1,065	6,603	3,562	941	
Electrabel	1,066	15.42	4628		3,110	6,222	314	194
Edf	4618	0.89	44,638	77	5,838	454	256	4,760
EnBW	729.4		3770	457	1,722	1,073	111	
Essent		119.58			1,076	1,998		
Nuon		51.99			778	1,783	833	
RWE	168.9	8.21	4,636	8,218	7,311	2,853	188	
Vattenfall	3.2	0.75	583	5,644	442	1,022	499	
fringe	586	4714.46	512	2399	13,185	18,729	458	55
Available capacity by nodes								
Germany	1,510	4,607	15,313	18,641	25,800	14,197	2,251	0
France	6,120	189	47,522	77	9,345	8,222	258	4,793
Merc (B)	0	21	2,097	0	1,564	2,588	195	54
Gram (B)	13	21	2,224	0	979	1,207	170	194

10 *Without pumped-storage plants.*

11 *The availability factors adopted for hydro are: 32.4% (Germany), 28.9% (France), 12.3% (Belgium), 0% (Netherlands). Those values are based on own computations. Sources: UCTE (2005b) and Eurostat (2006).*

Krim (NL)	0	101	337	0	3,128	4,431	833	0
Maas (NL)	0	101	0	0	0	2,917	0	0
Zwol (NL)	0	102	0	0	482	4,834	0	0

Sources: Eon (2005a, 2005b, 2006), Electrabel (2005); EdF (2005a, 2005b), EnBW (2005), Essent (2005a, 2005b), Nuon (2005), RWE (2005, 2006), Vattenfall (2005a, 2005b)

The original data concerning installed capacity in 2005 were modified to account for the fact that Germany and France are exporting a large share of their power to third countries such as Switzerland, Spain and Italy. Also, we reduced installed capacities by an individual availability factor.

Table 6: Duration of periods, reference prices and hourly reference demand (in MW)

	off-peak		**peak**	
duration of period	Germany: 5,136 h France, Netherl.: 6,600 h Belgium: 5,880 h		Germany: 3,624 h France, Netherl.: 2,160 h Belgium: 2,880 h	
reference price[12]	40 €/MWh		45 €/MWh	
reference demand	*large customers*	*small customers*	*large customers*	*small customers*
Germany	38,400	14,660	38,400	43,230
France	26,530	25,410	26,530	53,380
Merchtem (BE)	4,770	1,310	4,770	4,580
Gramme (BE)	2,050	560	2,050	1,960
Krimpen (NL)	4,300	2,560	4,300	6,240
Maastricht (NL)	950	570	950	1,390
Zwolle (NL)	1,570	930	1,570	2,280

Sources: UCTE (2005a, 2005b), Eurostat (2004)

Table 7: Average construction costs of nuclear and lignite-based plants [€/kW]

	Germany	**France**	**Merchtem**	**Gramme**	**Krimpen**	**Maastricht**	**Zwolle**
nuclear	17.69	15.52	15.52	15.52	21.40	21.40	21.40
lignite	15.12	13.28	15.12	15.12	15.12	15.12	15.12
coal	15.12	13.28	15.12	15.12	15.12	15.12	15.12

Source: IEA (2005)

Table 8: Annual CO_2 emssion caps per node and technology type [t CO_2]

Total annual CO_2 emssion caps per node and technology type [t CO_2]							
	Germany	**France**	**Merchtem**	**Gramme**	**Krimpen**	**Maastricht**	**Zwolle**
lignite	123,182,869	244,028	0	0	0	0	0
coal	167,853,449	28,927,900	6,108,257	3,823,519	22,691,829	0	3,496,631
gas	17,285,754	2,841,271	4,144,356	701,650	7,211,520	7,090,129	3,914,744
oil	0	3,236,882	62,472	220,356	0	0	0
sum	308,322,072	*35,250,080*	*10,315,08*	*4,745,525*	*29,903,349*	*7,090,129*	*7,411,375*
total	**403,037,615**						
Annual demand-based CO_2 emssion caps [t CO_2] for large consumers							
	Germany	**France**	**Merchtem**	**Gramme**	**Krimpen**	**Maastricht**	**Zwolle**

12 Estimates for 2005 EEX spot prices.

lignite	25,411,590	1,760	0	0	0	0	0
coal	48,396,148	16,255,090	1,839,413	3,074,365	12,357,404	0	2,918,513
gas	505,094	123,922	820,866	388,253	838,303	5,553,068	355,124
oil	0	162,334	265	10,361	0	0	0
sum	*74,312,832*	*16,543,107*	*2,660,544*	*3,472,980*	*13,195,707*	*5,553,068*	*3,273,636*
total	**119,011,874**						

Annual capacity-based CO_2 emssion caps [t CO_2] for large consumers							
	Germany	**France**	**Merchtem**	**Gramme**	**Krimpen**	**Maastricht**	**Zwolle**
lignite	110,864,582	0	0	0	0	0	0
coal	0	0	4,275,780	3,441,167	22,691,829	0	3,496,631
total	**144,769,988**						

Source: European Commission (2004), European Commission (2006), République Française (2005)

The demand-based caps for large consumers were calculated as the shares in total emission caps that equal the shares in emission of large consumers in the basic case. To obtain a feasible solution it was necessary to shift 30% of Merchtem's allowances to Gramme and 10% of Krimpen's allowances to Maastricht and Zwolle.

Capacity-based caps were calculated multiplying the according total caps with the shares in capacities of industrial consumers.