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Liberalising the Energy Markets of Western Europe-
A Computable Equilibrium Model Approach

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Liberalising the Energy Markets of Western Europe – A Computable Equilibrium Model Approach

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Abstract

Using a computable equilibrium model, we examine the short-run effects of a radical liberalisation of the West European natural gas and electricity markets. In each model country, oil, gas, coal and electricity are produced, traded and consumed. There are world markets for oil and coal, and well-integrated competitive markets for gas and electricity in Western Europe. Gas and electricity are transported and traded across markets under the assumption of ideal third-party access regimes for transportation and limited capacities in the transportation networks. We find that relative to the base year 1996, a radical liberalisation reduces the average end-user price of natural gas by around 20 per cent, and the average end-user price of electricity by around 50 per cent. Supply of electricity increases by around 20 per cent, mainly due to increased coal power production. After such liberalisation, coal power emerges with the largest market share of electricity production in Western Europe.

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1 Introduction

The past 15 years have seen various initiatives to liberalise the natural gas and electricity industry in Western Europe. The process has been driven both at the national level and by the EU Commission, which has worked out several proposals to enhance competition at all levels in the energy markets. The objective of the Commission is to transform heavily regulated national markets into efficient European markets through regulatory reforms. If this process succeeds, there will be major changes in the natural gas and electricity industry. The purpose of the present article is to examine, within a computable equilibrium model, the short-run effects that would follow from such a radical liberalisation of the energy markets of Western Europe.[1]

Until the mid-1980s, the natural gas and electricity industry in all Western European countries was subject to various government regulations and controls. These regulations significantly affected all levels of the industry – extraction, import, transport, distribution and prices. One example is France, where the state-owned company Gaz de France has had a legal monopoly on imports and a virtual monopoly on transport. Another example is Germany, which for many years had regional monopolies in electricity production. However, the past 15 years have seen tendencies in some countries toward greater competition in the energy industry. The obvious example here is the UK, where liberalisation started in 1986 when British Gas Corporation was transferred intact to the private sector as a 100 percent monopoly supplier. Since then, additional reforms have been imposed; today most experts assess the UK natural gas and electricity industry as being fairly competitive.

The EU Commission has also made efforts to liberalise the energy markets of Western Europe. In 1988, the Commission published a working document on the Internal Energy Market (see Commission of the European Communities, 1988), proposing various initiatives like harmonisation of taxation, price transparency and

[1] While we use an empirical approach to studying the effects of liberalisation, there is an extensive literature on optimal management and expansion of a completely integrated and efficient, mixed hydro-thermal electricity industry; see e.g. Nelson (1964). For a theoretical discussion on the long-term gains from interconnecting existing systems of different technologies (no market failures within each system prior to trade), see von der Fehr and Sandsbråten (1997).

interconnection of grids. These proposals met with opposition from several Member States as well as from part of the energy industry, leading the Commission to prepare a set of revised policy proposals. A milestone was reached in 1998, when the Member States agreed to establish an internal market for natural gas. The main idea is gradually to open up national markets for competition, partly through extensive use of third-party access to transport and distribution (Thackeray, 1999). These regulatory reforms are in line with an earlier EU directive on how to achieve enhanced competition in the Western European electricity markets (see IEA, 2000).

The starting point of the present study is the assumption that EU succeeds in establishing efficient internal markets for natural gas and electricity. Employing a computable equilibrium model of the energy markets, we examine the short-run effects that will follow from a radical liberalisation of these markets. We seek to answer questions like

- To what extent will enhanced competition push down prices on natural gas and electricity?
- To what extent will a radical liberalisation change the total production of electricity in Western Europe?
- Which electricity technologies will capture a larger market share?

In order to answer these questions, we construct a numerical equilibrium model of the Western European energy markets, with 13 European countries. In each country there is production, trade and consumption of four energy goods: oil, coal, natural gas and electricity. There are competitive world markets for oil and coal, and well-integrated competitive markets for natural gas and electricity in Western Europe. Natural gas and electricity are transported and traded under the assumption of ideal third-party access regimes for transport and limited capacities in the transport networks.

In each country various technologies are available for supplying electricity – for example, gas power, coal power, nuclear and reservoir hydro power. Because electricity cannot be stored (except in limited-capacity hydro-reservoirs), and demand varies significantly between day and night as well as with the seasons (summer vs.

winter), there are seasonally differentiated and time-of-day differentiated markets for electricity. On the other hand, all fossil fuels are traded in annual markets. End-users demand all four energy goods. In addition, fossil fuels are used in the production of thermal power (e.g., gas power).

Our model allows for an analysis of a radical liberalisation that includes both natural gas and electricity. Due to inter-fuel competition, natural gas can be used to produce power, and power competes with natural gas in end-user demand. It would therefore seem logical to examine these two energy goods simultaneously. Yet, to our knowledge, there have been no studies on liberalisation of the Western European energy markets that deal with this type of inter-fuel competition. Although Amundsen and Tjøtta (1997) examine a liberalisation of the Western European *electricity* market, their study does not model any market for natural gas: that is, gas power producers are faced by an exogenous price for natural gas. Similarly, there exist studies on the effects following from a liberalisation of the *electricity* market in a given region, such as Johnsen (1998) for the case of the Nordic electricity market; as well as studies on national electricity markets, such as Andersson and Bergman (1995) for the case of Sweden, and Kemfert (2000) for the case of Germany. Golombek, Gjelsvik and Rosendahl (1995) analyse a liberalisation of the Western European *natural gas* market without specifying a market for electricity; in their study, demand functions for natural gas reflect the price of electricity in the base year of the model.

The impacts of a liberalisation will depend on the marginal cost of electricity production. Some studies, e.g. Amundsen and Tjøtta (1997), have an increasing marginal cost function for thermal power production, without specifying the marginal cost function of each type of technology (coal power, gas power and oil power). Other studies, e.g. Johnsen (1998), allow for variations in marginal cost of production across technologies, but not across plants using the same type of technology (within the same country). In the present study, the marginal costs of electricity production differ across countries, technologies *and* across plants that use the same type of technology (within the same country). Moreover, in contrast to several electricity studies, we include cost elements of electricity production other than fuel costs, namely (fixed) start-up costs and (fixed) maintenance costs. Because all cost elements are included in the Lagrangian of the electricity producers, we can derive optimal capacity utilisation over time at the plant level. This is an improvement relative to the traditional 'load duration' approach, in which the composition of technologies in high load periods is de facto exogenous and the start-up cost is a variable cost; see e.g. Kahn, Marnay and Berman, 1992.

The rest of the paper is organised as follows. In Section 2 we describe the computable equilibrium model in detail, focusing on electricity supply. Section 3 presents the equilibrium outcome of the model. We find that, relative to the base year 1996, a radical liberalisation reduces the average end-user price of natural gas by around 20 per cent, and the average end-user price of electricity by around 50 per cent. Supply of electricity increases by around 20 per cent, mainly due to increased coal power production. After liberalisation, coal power emerges with the largest market share. In Section 4 we summarise our conclusions.

2 The model

The model involves four energy goods: electricity, natural gas, oil and coal. In this model, electricity is produced, consumed and traded in four time periods, whereas fossil fuels are extracted, consumed and traded in annual markets. All markets are fully competitive. However, while electricity and natural gas are traded in Western European markets, oil and coal are traded in world markets. We distinguish between the 13 model countries (Austria, Belgium [including Luxembourg], Denmark, Finland, France, Germany, Great Britain, Italy, Netherlands, Norway, Spain, Sweden and Switzerland) in which production, trade and consumption are endogenous, and exogenous countries.

We begin with a detailed description of the modelling of electricity supply. Next, we present the other elements of the model – supply of fossil fuels, demand for energy, international trade in energy, demand and supply from the exogenous countries and equilibrium conditions.[2]

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[2] A full technical description of the model is given in Aune, Golombek, Kittelsen and Rosendahl, 2001.

Electricity supply

Production of electricity takes place in each model country through various technologies (some are not available in all countries): gas power, oil power, coal power, pumped storage power, reservoir hydro power, nuclear, waste power and renewables. In all countries in our model, electricity is produced in two seasons (summer and winter); within each season there are two periods (day and night). In general, for each technology and each country, efficiency varies across electricity plants. However, instead of specifying heterogeneous plants within each category of electricity production (technologies and countries), we model the supply of electricity from each category *as if* there were one single plant with increasing marginal costs.

We begin by studying electricity supplied from the combustion of fossil fuels. Then we examine the supply from plants based on non-fossil fuels. There are three *fossil fuel technologies:* gas power, oil power and coal power. Because electricity production based on these technologies can be modelled in the same way, we focus on one type only (henceforth referred to as gas power). To simplify notation, we drop country specification.

There are four types of costs involved in gas power production. Firstly, there are costs directly related to combustion of natural gas. Let $\overline{\nu}_t$ be the average amount of natural gas (in the sector) required to produce one unit of electricity in period t: that is, $\overline{\nu}_t$ is a combination of the inverse energy efficiency and a unit conversion factor ($\overline{\nu}_t$ is increasing in electricity production, which reflects increasing marginal costs). Then fuel costs in period t are given by $\overline{\nu}_t P^G$, where P^G is the (annual) user price of natural gas for the gas-power producer. In addition to fuel costs, there are other inputs (with exogenous prices) that are assumed to vary proportionately to production, implying a constant unit operating cost c^O.

Let K^P be installed power capacity in the gas power sector. In addition to choosing an electricity output level, the producer is assumed to choose the level of power capacity that is maintained (K^{PM}), thus incurring a unit maintenance cost c^M per power unit. Finally, if the producer chooses to produce electricity in only one of the periods in each season (e.g. daytime), he will incur a daily start-up cost. In this model the start-up cost c^S is expressed as a cost per start-up power capacity (K^{PS}) in each season. The short-run cost function is therefore

$$C = \sum_{t \in T} \left(c^O + \bar{\nu}_t P^G \right) y_t + c^M K^{PM} + \sum_{t \in T} c^S K_t^{PS} \tag{1}$$

where y_t is production of power in period t and T is the set containing all four time periods. Operating surplus (short-run profits) are given by:

$$\Pi = \sum_{t \in T} P_t y_t - C \tag{2}$$

where P_t is the price of electricity in period t.

The producer maximises surplus, given several constraints. Below, the restrictions on the optimisation problem are given in solution form, where the Kuhn-Tucker multiplier – complementary to each constraint – is also indicated. The first constraint requires that maintained power capacity (K^{PM}) should be less than or equal to total installed power capacity (K^P):

$$K^{PM} \leq K^P \perp \lambda \geq 0, \tag{3}$$

where λ is the shadow price of installed power capacity.[3]

Secondly, in each period, production of electricity is constrained by the maintained energy capacity, i.e. the number of hours available for electricity production (ψ_t) multiplied by maintained power capacity (K^{PM}):

$$y_t \leq \psi_t K^{PM} \perp \mu_t \geq 0. \tag{4}$$

All power plants need some down-time for technical maintenance. Hence, total annual production cannot exceed a share (ξ) of the rated instantaneous capacity:

[3] In general, $a \leq 0 \perp b \geq 0$ means $a \leq 0 \; or \; b \geq 0 \; or \; ab = 0$.

$$\sum_{t \in T} y_t \leq \xi \sum_{t \in T} \psi_t K^{PM} \perp \eta \geq 0. \tag{5}$$

Finally, for each season, the difference between capacity use in one period and capacity use in the other period is constrained by the capacity that is started each day in that season (K_t^{PS}):

$$y_t / \psi_t - y_u / \psi_u \leq K_t^{PS} \perp \phi_t \geq 0, \tag{6}$$

where y_t / ψ_t is actual capacity in period t and y_u / ψ_u is actual capacity in the other period in the same season. For each pair of periods in the same season there are thus two inequalities, which together imply two different non-negative start-up capacities (only one will be non-zero in equilibrium).

For gas power (as well as oil power and coal power) the Lagrangian of the optimisation problem is

$$\begin{aligned} \mathrm{L} &= \sum_{t \in T} P_t y_t - C - \lambda \left\{ K^{PM} - K^{P} \right\} \\ &- \sum_{t \in T} \mu_t \left\{ y_t - \psi_t K^{PM} \right\} - \eta \left\{ \sum_{t \in T} y_t - \xi \sum_{t \in T} \psi_t K^{PM} \right\} \\ &- \sum_{t \in T} \phi_t \left\{ y_t / \psi_t - \sum_{u \in T} \delta_{tu}^{S} \, y_u / \psi_u - K_t^{PS} \right\} \end{aligned} \tag{7}$$

where the selector δ_{tu}^{S} is equal to 1 for the other period *u* in the same season as period *t*, and to 0 for all other periods. The first-order condition with respect to produced electricity is:

$$P_t - c^{O} - \nu_t P^{G} - \mu_t - \eta - \left(\phi_t / \psi_t - \sum_{u \in T} \delta_{tu}^{S} \, \phi_u / \psi_u \right) \leq 0 \perp y_t \geq 0. \tag{8}$$

where $\nu_t = \dfrac{\partial(\overline{\nu}_t y_t)}{\partial y_t}$ is the marginal efficiency in period t. Hence, in each period an internal solution requires that the difference between the price of electricity (P_t) and the marginal cost of production ($c^O + \nu_t P^G$) should be equal to the sum of several shadow prices. These are the shadow price of the periodic energy capacity, the shadow price of the annual energy capacity, and the difference (measured per hour) between the shadow price of capacity used in this period and in the other period, in the same season. Next, the first-order condition with respect to maintained capacity is

$$\sum_{t \in T} \psi_t \left\{ \mu_t + \eta \, \xi \right\} \le c^M + \lambda \ \perp K^{PM} \ge 0, \qquad (9)$$

that is, the cost of increasing maintained capacity marginally (the sum of the maintenance cost and the shadow price of installed capacity) should be equal to the value of increased production following from this policy (or maintained capacity should be zero). Finally, the first-order condition with respect to the start-up capacity is

$$\phi_t \le c^S \ \perp K_t^{PS} \ge 0, \qquad (10)$$

that is, in each period the shadow price of start-up capacity should be equal to the start-up cost (or the start-up capacity should be zero).

Equations (8) to (10) imply that *if* a plant is producing during daytime, costs will increase if the plant does not produce during the night (the plant will incur a start-up cost). Hence, the start-up component tends to smooth out production from a plant over the day. However, smooth production combined with high demand during daytime and low demand at night will lead to increased price variation between day and night.

We now turn to *pumped storage power.* This is when a producer buys electricity in one period (e.g. winter night) and uses that energy to pump water to the reservoir in order to produce electricity in a different, higher-cost, period (e.g. winter day). For this technology, the Lagrangian is similar to (7), except that the pumped storage producer uses electricity (and not fossil fuels) as an input.

The *reservoir hydro power* producer has two additional restrictions in his optimisation problem. Firstly, total production of reservoir hydro power in season *s* (y_s^R) plus the reservoir filling at the end of season *s* (R_s) should not exceed the sum of the reservoir filling at the end of the previous season (R_{s-1}) and the seasonal inflow capacity (K_s^I) expressed in energy units:

$$y_s^R + R_s \leq R_{s-1} + K_s^I \perp \alpha_s \geq 0. \tag{11}$$

Secondly, the reservoir filling at the end of season *s* cannot exceed the reservoir capacity K^R:

$$R_s \leq K^R \perp \beta_s \geq 0. \tag{12}$$

These two restrictions have the following impact on the first-order conditions. Firstly, the sum of the shadow prices in (8) should include the shadow price of the inflow capacity, as a higher inflow will lead to increased production (if production is restricted due to limited inflow). Secondly, an additional first-order condition requires that the sum of the shadow price of inflow capacity and reservoir capacity in season s should be equal to the shadow price of the inflow capacity in the next season (alternatively, that the reservoir should be empty at the end of season s):

$$\alpha_{s+1} \leq \alpha_s + \beta_s \perp R_s \geq 0. \tag{13}$$

The *waste power* producer has an additional restriction (relative to the gas power producer). For waste power, we require that production in each season should be constrained by the available waste in that season (measured in energy units); that is, we implicitly assume zero reservoir size. For *nuclear*, the Lagrangian is similar to that one for gas power, except that start-up capacity is exogenously set at zero. This constraint reflects the fact that, due to the time and costs involved in starting up and shutting down nuclear plants, it is not optimal to vary production between day and night. Finally, the energy capacity for *renewables* (geothermal, solar and wind) varies across periods, but there is no storage possibility. Thus, in each period, production from renewables is exogenous (equal to observed supply in the base year).[4]

Supply of fossil fuels

For each of the model countries, supply of crude oil and coal is price dependent (in the standard way). For natural gas, currently sold on long-term contracts in Western Europe, extraction in the model countries is exogenous (all quantities are set equal to the observed values in the base year).[5]

Energy demand

In each model country, the two end-user sectors (household and manufacturing) demand all four energy goods. For each country and each type of end-user, demand is derived from a nested CES utility function. This functional form ensures globally fulfilment of regularity conditions derived from economic theory, which is important when modelling institutional changes that result in large price movements. Five nest levels, with associated substitution and share parameters, are necessary to achieve the desired own- and cross-price elasticities. The structure of nests is designed to facilitate meaningful economic interpretations.

At the top nest level there are substitution possibilities between energy-related goods and other consumption. At the second level the consumers face a trade-off between consumption based on the four different energy sources. Each of these is a nest describing complementarity between the actual energy source and consumption goods that use this energy source (e.g. electricity and light bulbs). Finally, the fourth and fifth levels are specific to electricity in defining the substitution possibilities between summer and winter (season), and between day and night in each season.

[4] For supply of electricity, a system levy ensures that there is always a reserve power capacity in each period and country. The levy is the result of a social optimisation problem not modelled here, and enters complementary to the reserve capacity constraint. Hence, this tax will be positive only if the constraint is binding.

In addition to final demand, there is intermediate demand from electricity producers; gas power producers demand natural gas, pumped storage producers demand electricity, etc. According to Shephard's lemma, conditional on a given output level demand from an electricity producer is the derivative of the cost function w.r.t. the input price. Hence, using (1) intermediate demand (for natural gas) is

$$x^G = \frac{\partial C}{\partial P^G} = \sum_{t \in T} \overline{\nu}_t y_t. \qquad (14)$$

Trade in energy and transport of energy

There is trade in all energy goods. Transport of goods from producers to end-users takes place on three levels: international transport, national transport and distribution (to households). Each country is represented by a central node. For each country, oil and coal is transported from the world market to the central node, at a given cost. Electricity (gas) is traded via international transmission lines (pipelines) that run between the nodes. All lines have given capacities. Each line is owned by one agent, who, being a price taker, maximises the difference between (i) the purchasing price in one country and (ii) the sum of the selling price in another country plus the cost of transmission (loss in transport and the transport tariff). Hence, all arbitrage possibilities are exploited. However, for each line the (endogenous) transport tariff ensures that demand for transport does not exceed supply (the fixed capacity).

Equilibrium

In equilibrium, for each model country, and each of the three fossil fuels, the total quantities consumed are (less or) equal to total quantities delivered at the central node (minus a fixed proportion in distribution losses). For each period and each country, this condition also holds for electricity. For oil and coal, the sum of demand from all countries should be (less or) equal to total supply.

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[5] For exogenous countries, supply of crude oil and coal are also price dependent (in the standard way). Similarly, demand for crude oil and coal are price dependent. On the other hand, non-model countries have an exogenous net export of natural gas and electricity to the region of the model countries.

3 Equilibrium outcome

The model is solved in the GAMS modelling language (see Brooke, Kendrick, Meeraus and Raman, 1998), using the mixed complementarity (MCP) solver PATH (see Ferris and Munson, 1998). Much of our data build on statistics published by international organisations like OECD, UNIPEDE, UCPTE and NORDEL, supplemented with national sources when necessary. Costs parameters build on Golombek, Gjelsvik and Rosendahl (1995) and Amundsen and Tjøtta (1997). The direct price elasticities for coal, oil, natural gas and electricity draw on three econometric studies: The SEEM model (Brubakk et al., 1995), the E3ME model (Barker, 1998) and Franzen and Sterner (1995). The weighted household (industry) short-run elasticities for coal, oil, natural gas and electricity are –0.19 (–0.19), –0.21 (–0.20), –0.22 (–0.27) and –0.32 (–0.20), respectively. Appendix A explains the main principles behind the calibration of the model.

Prices

Through increased domestic and international competition, non-competitive national markets with limited international trade are transformed into efficient well-integrated markets. Liberalisation therefore leads to lower (average) prices for electricity and natural gas. In equilibrium, all price differences reflect cost differences and tax differences only.

After the radical liberalisation, the aggregate *end-user price of electricity* (aggregated over periods, sectors and countries) is 59.5 USD/MWh: that is, 50 per cent lower than in the base year 1996, as shown in Table 1. The drop is somewhat larger for household (54 per cent) than for industry (41 per cent). The percentage difference is higher when prices are measured without taxes, since the household segment pays higher taxes than the industry sector.

The price drop in aggregate end-user price can be decomposed into (i) lower average price due to removal of price discrimination (for a given total quantity), and (ii) lower average price due to elimination of market power and hence increased production. In order to identify the magnitude of these effects, in a separate run of the model we imposed a tax on production of electricity (faced by all power producers) that ensures that total equilibrium production is equal to total production in the base year. The difference between the new equilibrium and the base year reflects the partial effect of no price discrimination. We find that the partial effect of no price discrimination is a reduction in aggregate end-user price by 7 per cent. As noted above, the total reduction in aggregate end-user price is 50 per cent.

The national *producer prices of electricity* (aggregated over periods) are in the range of 28 to 43 USD/MWh, with a weighted average of 36.0 USD/MWh, as shown in Table 1. Producer prices – and hence end-user prices – vary over season, and between day and night. This is because demand varies, and because marginal costs of production are increasing in total power production (less efficient plants are phased in as total production increases). In addition, the start-up cost tends to increase the price difference between daytime and night, cf. Section 2. The producer price (aggregated over countries) is highest for winter day (39.7 USD/TWh), next highest for summer day, next lowest for winter night and lowest for summer night (31.0 USD/MWh). The price difference between winter and summer is much higher than the price difference between day and night. In Norway and Sweden, where reservoir hydro power has a substantial market share, period prices are equal except for winter day. For all other countries, prices differ across all four time periods. Maximum difference between highest and lowest producer price in a country is roughly 12 USD/MWh (for Belgium, Germany, Italy, the Netherlands and Great Britain).

Liberalisation also leads to decreased prices of *natural gas.* The aggregate *end-user price of natural gas* (aggregated over countries and sectors) is 269 USD/toe, which is 18 per cent lower than in the base year 1996. In percentage terms, the drop is lower than for electricity. Because total consumption of natural gas is unchanged relative to 1996 (cf. Section 2), the drop primarily reflects the removal of price discrimination, in addition to effects from other markets (The corresponding partial effect in the electricity market is 7 per cent, as indicated above).

With no price discrimination, the total exogenous natural gas quantity is redistributed, which, *cetibus paribus*, leads to lower prices in the household sector but higher prices in the other two sectors. However, in this case the average price has decreased, because price discrimination has come to an end. Note that a lower price of electricity has a negative impact on demand for natural gas (positive cross-price elasticities), and hence contributes to a lower equilibrium price of natural gas (and vice versa). The average *producer price of natural gas* is 126 USD/toe, as shown in Table 1.[6]

Table 1 Prices of electricity and natural gas in a liberalised Western European energy market. Percentage change relative to 1996 in parenthesis.

Price of electricity (USD/MWh)	
Aggregate producer price	
Summer day	39.4 (n.a.)
Summer night	31.0 (n.a.)
Winter day	39.7 (n.a.)
Winter night	31.8 (n.a.)
Annual	36.0 (n.a.)
Aggregate end-user price	
Household	71.7 (–54)
Industry	42.9 (–41)
Total	59.5 (–50)
Price of natural gas (USD/toe)	
Aggregate annual producer price	126 (n.a.)
Aggregate annual end-user price	
Household	363 (–27)
Industry	191 (–4)
Gas power	166 (–9)
Total	269 (–18)

Quantities

Total production of electricity increases by 20 per cent (relative to 1996), that is, by 496 TWh, cf. Figure 1. The increase in production for coal power, oil power and gas power is 57 per cent, 16 per cent and 12 per cent, respectively. For these technologies, the changes in production can be decomposed into (i) changed production due to changed use of input (the quantity effect), and (ii) changed production due to more efficient composition of plants (the allocation effect). In order to identify these two effects, in a separate run of the model we imposed taxes on the use of fossil fuels in electricity production (one tax for each fossil fuel). These taxes ensure that, for each

[6] The world market price of crude oil decreases by 0.5 per cent. The drop reflects lower total use of oil in the 13 model countries (16 per cent), but also that the 13 model countries have only a small share of world consumption, and cross-price elasticities are minimal. On the other hand, the world market price

fossil fuel, total use of the fuel in power production in the *new* equilibrium is equal to total use in the *original* equilibrium. We find that for gas power the quantity effect is due to an increase of 23 TWh, whereas 12 TWh is attributed to the allocation effect. For coal power and oil power most of the changes are due to the quantity effect. The increase in reservoir hydro (5 per cent) is due to more precipitation in equilibrium (a hydrological normal year) than in the base year, whereas the decrease for pumped storage hydro (76 per cent) reflects a smaller price difference between daytime and night in equilibrium than in the base year.[7]

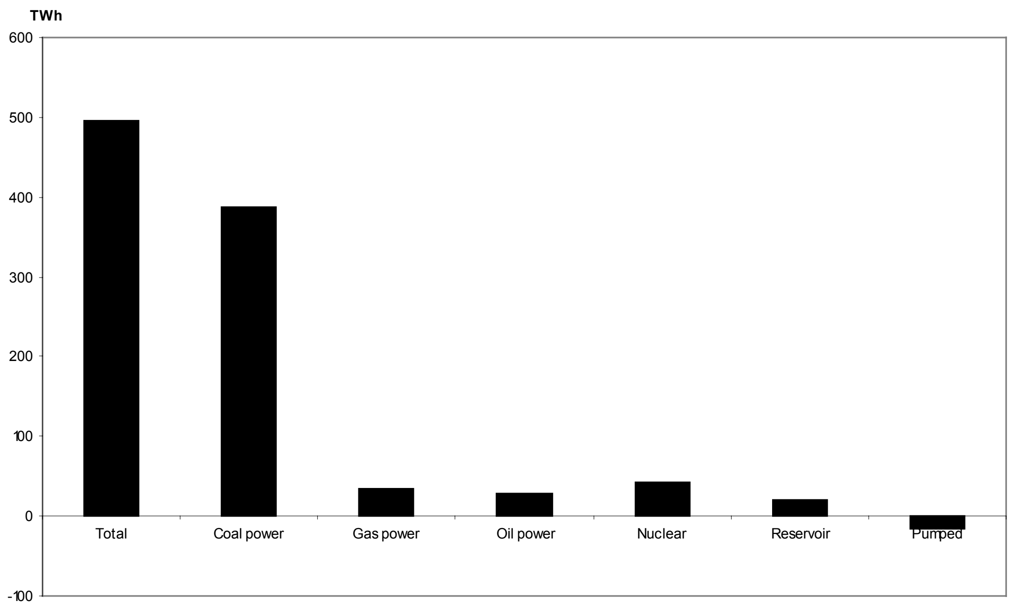

Figure 1. Changes in supply of electricity

The discussion above suggests that liberalisation has an impact on the composition of electricity supply. After liberalisation, coal power emerges with the largest market share (36 per cent versus 29 per cent in 1996), as shown in Table 2. Nuclear, which due to technical constraints (cf. Appendix A) can increase production only slightly relative to the base year, has the second largest market share (30 per cent). The new market shares of gas power (12 per cent) and oil power (7 per cent) are only slightly

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of coal increases by almost 4 per cent, which partly reflects increased use of coal in the model countries (45 per cent).

[7] In the base year wholesale prices differed between daytime and night, whereas end-user prices did not differ.

different from the 1996 market shares. The increase in coal power production is the main force behind higher total emissions of CO_2 – 10 per cent more than in 1996.

Table 2 Market shares and rates of capacity utilisation of supply of electricity in a liberalised Western European energy market. Change in percentage points relative to 1996 in parenthesis.

Technology	Market share	Capacity utilisation
Nuclear	0.30 (0.35)	0.84 (0.80)
Coal power	036 (0.29)	0.88 (0.56)
Gas power	0.12 (0.13)	0.41 (0.37)
Oil power	0.07 (0.08)	0.34 (0.30)
Reservoir hydro	0.14 (0.13)	0.42 (0.40)
Pumped storage hydro	< 0.01 (0.01)	0.02 (0.08)

Also the annual rates of capacity utilisation change after liberalisation. For coal power, the rate increases from 56 per cent (base year) to 88 per cent (after liberalisation), as shown in Table 2. Nuclear, which had the highest rate of capacity utilisation in the base year (80 per cent), has a rate of capacity utilisation of 84 per cent in equilibrium. The rates for gas power and oil power increase by around 4 percentage points (These rates are 41 per cent and 34 per cent, respectively, after the liberalisation).

Production of electricity increases in all countries except Austria. Percentage increases are highest in the Netherlands (due primarily to more gas power), Great Britain (due primarily to more coal power), Denmark (due primarily to more coal power and gas power) and Belgium (due primarily to more coal power and gas power).

Consumption of electricity increases in all model countries (except Norway), in all periods, and for all end-users. Relative to 1996, total consumption at summer night has increased by around 30 per cent. For the other periods, the rise is less pronounced (13 to 20 per cent). Industry consumption increases by almost 10 per cent, whereas household consumption increases by around 25 per cent. We also find a rise in gross trade in electricity. In 1996 gross trade amounted to 180 TWh (7.7 per cent of total consumption); after liberalisation, gross trade increases by around 45 per cent. In equilibrium, gross trade varies between 58 TWh (summer night) and 71 TWh (winter night).

Due to redistribution of *natural gas* quantities (see discussion above) the composition of natural gas consumption changes, albeit only slightly. The share of household consumption increases from 48 per cent (base year) to 49 per cent. For industry, the share of consumption decreases from 32 per cent (base year) to 31 per cent.

5 Concluding remarks

This study has investigated the short-run effects following from a radical liberalisation of the natural gas and electricity markets in Western Europe, using a computable equilibrium model of the energy markets. The main features of the model are disaggregated demand for four energy goods, with seasonally and time-of-day differentiated markets for electricity; supply of electricity based on several technologies with differences in efficiency across plants using the same type of technology; well-integrated competitive West European markets for natural gas and electricity; and competitive world markets for oil and coal.

We find that, relative to 1996, a radical liberalisation leads to a significant reduction in end-user prices of natural gas (around 20 per cent) and electricity (around 50 per cent). The liberalisation leads to an increase in total welfare in the 13 model countries by 15 billion USD, which corresponds to 2 per cent of total energy expenditures for the end-users in the model countries. The consumer surplus of the end-users increases by 162 billion USD, primarily due to increased surplus for the households. On the other hand, operating surplus in electricity production, extraction of natural gas and transmission of natural gas decreases by 118, 5 and 6 billion USD, respectively. Also tax revenues decrease (-19 billion USD), primarily due to lower VAT income.

Because production of electricity increases and a higher share of electricity supply is based on fossil fuels (coal), emissions of CO_2 increase in Western Europe by around 10 per cent. In a companion paper we plan to apply the same model to identify the level of carbon taxes that would have to be imposed to ensure that CO_2 emissions in Western Europe are not increased (or to ensure that the Kyoto emission target for Western Europe is reached), and examine the impact that such a policy would have on the energy markets of Western Europe.

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Appendix A Data

Below we give an overview of our main data sources and explain the main principles of the calibration of the model. The base year of the model is 1996. For further details, see Aune et al. (2001).

Demand

In each country, demand is divided into two end-user groups –'household' and 'industry'. Household covers services and agriculture in addition to households, whereas industry covers both the industrial and the transport sectors.

Base-year demand for fossil fuels is taken from *Energy Balances of OECD countries, 1995–1996* (IEA 1998b), whereas base-year demand for electricity is taken from *Energy Statistics of OECD countries, 1995–1996* (IEA 1998e). In order to calibrate period demand for electricity, the annual consumption quantities are split up according to the base-year shares of electricity consumption. These are based on UCPTE (1998), which gives monthly quantities of electricity consumed and the consumption load at 03:00 and 11:00 hours of the third Wednesday of each month. For the Nordic countries, equivalent figures are found in NORDEL (1997a; 1997b). Base-year prices and taxes are taken mainly from *Energy Prices and Taxes, 2nd Quarter 1998* (IEA 1998c).

The direct price elasticities for coal, oil, natural gas and electricity build on three econometric studies: The SEEM model (Brubakk et al. 1995), the E3ME model (Barker 1998) and Franzen and Sterner (1995). In addition, quantities from the IEA statistics are used to weigh the original elasticities. Our short-run elasticities lie in the interval (–0.05 ; –0.43). Weighed household (industry) short-run elasticities for coal, oil, natural gas and electricity are –0.19 (–0.19), –0.21 (–0.20), –0.22 (–0.27) and –0.32 (–0.20), respectively. Estimates of cross-price elasticities vary significantly in the literature. We have chosen equal elasticities across fuels and countries. Because substitution possibilities differ across sectors, the cross-price elasticity of the household sector (0.025) is lower than for industry (0.05).

Supply of fossil fuels

Base year supply of fossil fuels for the model countries is taken from IEA (1998b); for other countries base-year supply (of oil and coal) is taken from *Energy Statistics and Balances of non-OECD countries, 1995–96* (IEA 1998d). Short-run supply elasticities for oil and coal are set to 1; see Golombek and Bråten (1994).

Electricity supply

Because efficiency differs across plants with the same type of technology, we assume that thermal efficiency is a linear function of capacity utilisation.[8] In order to determine a linear function, one needs two exogenous values. We let one point be the thermal efficiency of the most efficient plant, which in general is assumed equal to the efficiencies reported for new plants in *Projected Costs of Generating Electricity, Update 1992* (IEA, 1992).

A candidate for the second point of the linear function could be observed efficiency, calculated as net electricity production to fuel use.[9] However, there are problems involved in using the observed average efficiencies. Firstly, the unused parts of *all* electricity capacities have unobserved efficiency. Assuming these are mainly vintage plants with lower efficiency, the ('true') average efficiency of total capacity will be lower than the observed average efficiency. Secondly, the different electricity-producing technologies do not have a constant rate of capacity utilisation throughout the year. Capacity utilisation rates are not known from primary data. Instead of using observed average efficiency directly to determine the second point, we have calibrated the rate of capacity utilisation for each technology and period by imposing the following condition: for each country, the outcome should be consistent with cost minimisation in electricity production *given* our data (annual production from different technologies, period consumption, etc.). The problem is solved by running the electricity production block of the model. This solution provides the efficiency of

[8] For pumped storage we assume a fixed efficiency, calculated as the ratio of electricity produced to electricity consumed, with data from IEA (1998a).

[9] In some countries a substantial share of power plants produce both heat and electricity. The mix of heat and electricity production shows a wide dispersion between countries and fuels, and the data did not lend support to a common trade-off between heat and electricity across fuels. We therefore estimate trade-offs separately for each fuel on 1996 data from the cross-section of the model countries. The trade-offs were used to transform produced (and consumed) heat to produced (and consumed) electricity.

the least efficient plant (for each technology and country), which we have used as the second point in the linear efficiency function.

All electricity plants require some down-time for maintenance and upgrading. Our model reflects this by restricting total annual production to a fraction of installed capacity. For most technologies the fraction is set to 0.90 (conversation with industry experts). However, because nuclear is typically run as base-load in most countries, we have assumed that actual usage in 1996 reflects maintenance and upgrading only. The exception is France, which had a capacity utilisation in 1996 of 0.76: that is, production was probably restricted also due to low base-load demand relative to nuclear capacity. For France we have used the average rate of capacity utilisation for all other countries as an estimate (0.84).

Supply of reservoir hydro

For Norway, Sweden and Finland, inflow capacity –the amount of precipitation in the catchment area in a hydrological normal year – is documented in NORDEL (1997a). For the other model countries, our estimates are based on data from IEA (1998a).

Reservoir capacity measures how much water (in GWh) can be stored in the reservoir: that is, the maximum amount of water that can be transferred from end of the summer season to beginning of the winter season, and vice versa. NORDEL (1997a) provides data on nominal reservoir capacities, whereas from Nordpool (1999) we obtain the maximum, minimum and median filling share for Norway, Sweden and Finland for 1 April and 1 October. These two sources are used to estimate feasible reservoir capacity for the Nordic countries. The estimates, in combination with information from UNIPEDE (1997), are used to estimate feasible reservoir capacity for the remaining countries in our model.

Transport of electricity and natural gas

We have used UCPTE (1998) and NORDEL (1998) as sources for international transmission capacities for electricity. The cost estimates of international transmission, national transport and distribution of electricity are based on Amundsen et al. (1997), but inflated to 1996 prices. The resulting 3.2 USD/MWh for industry domestic transport costs is used in all countries, but the household distribution costs of 11.8 USD/MWh are varied across countries, in proportion to estimated distribution losses.

The starting point for capacity figures for transport of natural gas is Grabarczyk, McCallum and Wergeland (1993), but these estimates have been revised by industry experts. The main source for costs of natural gas transport is Golombek, Gjelsvik and Rosendahl (1995). However, due to substantial cost reductions in construction of new transmission lines over the last decade, our cost figures are lower than those in Golombek et al. (1995). For costs of domestic transport and distribution of natural gas, we take our starting point in official cost estimates for Germany. According to *Natural Gas Distribution* (IEA, 1998f), costs of national transport in Germany is 55 USD per toe, whereas costs of distribution is 105 USD per toe. These figures are used to estimate the costs of the other model countries, under the assumption that for each type of cost, the difference between two countries is due to amount of natural gas transported/distributed (data from IEA, 1998b) and length of the domestic transport/distribution network (data from Figas, 1997).