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Long-run Effects of Liberalising the Energy Markets in Western Europe

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Abstract

Assuming successful establishment of efficient energy markets in Western Europe by the EU, we study the long-run effects following from its policy of radical liberalisation. To this end we build a numerical equilibrium model of the energy markets in Western Europe that allows for a detailed study of a radical liberalisation of the energy industry, taking into account inter-fuel competition, technological differences in electricity supply, transport of energy through transmission lines and investments. We find that the long-run effect of a radical liberalisation is a decrease in the aggregate user price of electricity by around 50 per cent, whereas the aggregate user price of natural gas drops by around 20 per cent. Supply of electricity increases by almost 50 per cent. If investments in nuclear power are not feasible, the market share of (old and new) coal power is close to 50 per cent. In the opposite case, coal power and nuclear power have market shares of about one third each. Liberalisation increases trade in electricity among the model countries by a factor of six, whereas trade in natural gas increases by 10 per cent.

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1 Introduction

Since the mid-eighties there have been attempts at liberalising the energy markets in several European countries. The most noteworthy experience thus far has been that of England and Wales, where large sections of the previously publicly owned monopolies in the electricity and gas industries were privatised in the 1980s, see e.g. Newbery (2000). The British Gas Corporation was initially transformed from a public to a private monopoly. The British power generation industry was privatised as well, but due to a limited number of companies, agents were able to exert some market power. Later reforms were designed to increase the level of competition, and there is evidence that these have resulted in lower wholesale energy prices after 1995, see e.g. IEA, Energy Prices and Taxes.

Starting with different ownership structures, other countries have also implemented reforms to enhance competition. The Norwegian electricity market was liberalised in the early nineties, retaining a mix of private, central and local government ownership. Although prices were already low by European standards because of the abundance of hydroelectricity, the reforms have probably enhanced market efficiency by making investments in new and costly hydro projects unprofitable. Recent experience in Germany shows that here as well, increased competition seems to have had a substantial effect on wholesale energy prices after 1995, see e.g. IEA, Energy Prices and Taxes.

Even with the abolition of formal monopolies and franchises, industry concentration and the limited size of the market in each country may lead to a continuation of market power. Competition could be facilitated by integrating the energy markets of several countries, such as the newly created Nordpool electricity market for the Nordic countries. Essential to the success of international competition is the degree of third-party access to electricity transmission lines and gas pipelines connecting different countries.

The EU commission has made several efforts to liberalise and integrate the Western European energy markets with the aim of lowering energy prices and increasing market efficiency. These have met with considerable opposition, but have resulted in directives with a time schedule for opening the national markets for competition, partly through extensive use of third-party access to transport and distribution (Thackeray, 1999; IEA, 2000). In the spring of 2001 the EU commission adopted three new proposals in order to speed up the completion of the internal energy markets.

It remains to be seen how successful the EU will be in establishing a competitive energy market, and how quickly reforms will be implemented. The aim of this paper is to examine the effect of a fully integrated and competitive Western European energy market, if and when it should be achieved (henceforth referred to as radical liberalisation of the energy markets in Western Europe). Essential to this assessment is a recognition of the substantial links connecting the markets for different energy types through fuel competition and the substitution possibilities in the electricity production industry as well as in end-user demand. Furthermore, it is important to take explicit account of the international gas pipelines and electricity transmission networks. Since the interaction among a large number of producers, transporters, traders, consumers and governments is complex, we establish a numerical model to calculate possible effects of a radical liberalisation. The model also aids in understanding the mechanisms at work in the corner case of perfect competition in the Western European energy industry.

The core of the model is a set of competitive markets for four energy goods: coal, natural gas, oil and electricity. All energy goods are produced and consumed in each of the model countries. Natural gas and electricity are traded in well-integrated Western European markets using gas pipelines and electricity transmission lines that connect the model countries. There are competitive world markets for coal and oil. While fossil fuels are traded in annual markets, there is seasonal and diurnal (day vs. night) trade in electricity.

There is competitive supply of all fossil fuels and electricity. In each model country electricity can be produced by a number of technologies: coal power, gas power, oil power, reservoir hydro, pumped storage hydro, nuclear power, waste power and renewables. Each electricity producer maximizes profits. The installed and maintained power capacity can either be used to produce electricity, or be sold as reserve capacity to the system operator. There are a number of costs related to supply of electricity. First, there are costs directly related to combustion of fuels. These costs are dependent on plant efficiency, which in our model differs across countries, technologies and plants. Second, there are other inputs that are assumed to vary proportionately to production, and third, there are maintenance costs for power capacity. Fourth, there are start-up costs if the capacity used during the day differs from the capacity used at night. For some producers there are additional constraints as well: for reservoir hydro, for example, the water filling at the end of a season cannot exceed the reservoir capacity.

In each model country there is demand for all types of energy from end-users. In addition, fossil fuel based electricity producers have a demand for coal, natural gas and oil. Demand from the end-user sectors is derived from a nested multi-good multi-period CES utility function. Finally, all investments made in power capacities and transmission capacities are determined by profitability so that marginal costs equal marginal revenue. For example, a producer of electricity compares the annualised costs of investment per unit power capacity to the shadow price of power capacity. The model determines all energy prices and quantities produced, traded and consumed in the model countries, as well as investments in the energy industry.

Our model allows for a detailed study of a radical liberalisation of the energy markets, taking into account factors like inter-fuel competition, technological differences in electricity supply, transport of energy through gas pipelines/electricity lines and investments in the energy industry. In particular, we can derive optimal capacity utilisation over time at the power plant level, and hence the model determines the composition of technologies in different periods. To our knowledge some of these features are new to the literature. In particular, we are not aware of any studies on liberalisation that take into account inter-fuel competition or investment.

As mentioned above, it may take several years for the EU to succeed in establishing efficient energy markets in Western Europe. Hence, one strategy could be to compare the expected outcome for a future year, say 2010, if the EU does not succeed in liberalising the energy markets with the predicted outcome in the same year if it does. This strategy proves not to be feasible, however, because it is very hard to predict the outcome in 2010 if the EU fails. A feasible strategy to identify the *pure* effect of liberalisation is to compare the observed outcome in the data year of the model (1996) with the hypothetical competitive long-run equilibrium, where model relations are calibrated using 1996 data. This is the approach used in the present paper.

Using the numerical equilibrium model we find that the long-run effect of a radical liberalisation of the energy industry, that is, transformation to fully competitive markets, is a decrease in the aggregate user price of electricity by around 50 per cent relative to the data year. Moreover, the aggregate user price of natural gas drops by around 20 per cent (relative to 1996). The short-run effects (no investments) are of similar magnitudes.

We are not aware of any similar studies on long-run effects of liberalisation, but Amundsen and Tjøtta (1997) study *short-run* effects of liberalising the Western European *electricity* market.[3] They do not explicitly distinguish between different fossil fuel based electricity technologies, and all electricity producers face exogenous prices of fuels. However, Amundsen and Tjøtta obtain similar results to ours and find that radical liberalisation leads to a drop in the aggregate user price of electricity by around 50 per cent (relative to 1990).[4] Moreover, they find that the price ratio between day and night for the industrial sector in the summer is reduced to 1.4, whereas the ratio in the winter is increased to 1.2. In our model, the corresponding long-run ratios are 1.3 (winter) and 1.25 (summer). These differences may reflect a number of factors, like a partial equilibrium model versus a full equilibrium model, different demand functions (linear versus nested CES), and different data sources.

While Amundsen and Tjøtta (1997) study short-run effects of a liberalisation of the Western European electricity market, Golombek, Gjelsvik and Rosendahl (1995) analyse long-run effects of a liberalisation of the Western European natural gas market. In the latter study there is no market for electricity, and hence demand functions for natural gas reflect the price of electricity in the data year of the model.

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[3] See also Newbery and Pollitt (1997) for a study on costs and benefits of restructuring and privatising generation and transmission in England and Wales.

[4] While Amundsen and Tjøtta (1997) compare simulated equilibrium prices with observed 1990 prices, in the present study we compare equilibrium prices with 1996 prices. Average user prices of electricity

Moreover, the study by Golombek, Gjelsvik and Rosendahl assumes imperfect competition - major suppliers of natural gas in Western Europe are Cournot players – whereas the present study assumes competitive supply. Golombek, Gjelsvik and Rosendahl find that the average industry price is almost unchanged (relative to 1990), whereas the average household price decreases by roughly one-third. These results are quite similar to the ones obtained in the present study; average industry price is roughly unchanged, whereas average household price decreases by around 30 per cent.

Turning to quantity effects, when we assume that investments in nuclear power capacity are not feasible we find that electricity supply increases by 50 per cent. This reflects large investments in coal power, but also investments in gas power. While production in currently existing gas power plants decreases somewhat, supply from existing coal power plants increases significantly. In equilibrium, the market share of (old and new) coal power is 44 per cent. The increase reflects that production of coal power is cheap, and that these benefits can be exhausted in a competitive market. On the other hand, oil power is phased out almost completely, and pumped storage hydro capacity is not used at all.

This liberalisation also leads to a radical increase in trade in electricity, and also a small increase in trade in natural gas. These effects partly reflect that the supply of electricity and natural gas has increased, but also that national markets have been exposed to more intense competition. Finally, if nuclear power investments are feasible, new nuclear power crowds out roughly 50 per cent of the new coal power production, whereas total production of electricity is almost unchanged (compared with the case of no nuclear power investments).

The rest of the paper is organized as follows. In Section 2 we describe the numerical model in detail. Section 3 provides a short description of our data. The equilibrium is presented in Section 4, whereas robustness of the equilibrium is analysed in Section 5. Our main findings are summarised in Section 6, which also provides some final remarks.

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in OECD Europe were 5-10 per cent higher in 1996 than in 1990. This was also the case for average user prices of natural gas.

2 The Model

There are four energy goods in the model: electricity, natural gas, oil and coal. 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. While electricity and natural gas are traded in well-integrated Western European markets, oil and coal are traded in world markets. We distinguish between model countries where investments, production, trade and consumption are endogenous, and exogenous countries. All countries in the latter group extract, trade and consume coal and oil, and some of these countries also export (or import) natural gas and electricity to the region of the model countries.

Electricity supply

Electricity is produced with various technologies: gas power, oil power, coal power, pumped storage power, reservoir hydro power, nuclear power, waste power and renewables. Production takes place in each model country, but some technologies are not available in all countries. Electricity is produced, traded and consumed in two seasons (summer and winter), and within each season there are two periods (day and night). In general, for each technology and each country, efficiency varies across power 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 decreasing efficiency (and hence increasing marginal costs).

We begin by studying electricity production based on combustion of fossil fuels. To simplify notation, we drop country specification and type of technology. For fossil-fuel based power production, for example coal power, total costs are given by:

$$C = c^{inv} K^{inv} + \sum_{t \in T} \left(\eta_t P^f + c^O \right) y_t + c^M K^M + \sum_{t \in T} c^S K_t^S \tag{1}$$

There are five types of costs involved in fossil-fuel based power production: one related to the investment decision and the others related to the operating decisions.

First, there are costs of investments, $c^{inv}K^{inv}$, where K^{inv} is investment in order to increase the initial capacity and c^{inv} is the annualised costs of investment per unit capacity. Second, there are costs directly related to combustion of the fossil fuel. Let $\bar{\nu}_t$ be the average amount of the fossil fuel required to produce one unit of electricity in period t ($\bar{\nu}_t$ is increasing in electricity production, which reflects decreasing efficiency). Then fuel costs in period t are given by $\bar{\nu}_t P^f y_t$, where P^f is the (annual) user price of the fossil fuel, $f = \{coal, natural\ gas, oil\}$ and y_t is sales of electricity in period t (T is the set containing all four time periods). Third, 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. Fourth, the producer is assumed to choose the level of power capacity maintained (K^M), 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. during the day), 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^S) in each season.

Profits for fossil-fuel based power production are:

$$\Pi = \sum_{t \in T} (P_t y_t + P_t^R K_t^R) - c^{inv}K^{inv} - \sum_{t \in T} \left(\bar{\nu}_t P^f + c^O\right) y_t - c^M K^M - \sum_{t \in T} c^S K_t^S \qquad (2)$$

Revenues consist of two parts: income from ordinary sales of electricity and income from sales of capacity to the system operator, who ensures that there is always a reserve power capacity available. Ordinary income in period t is given by $P_t y_t$, where P_t is the price of electricity in period t. Moreover, the producer sells K_t^R of his (maintained) capacity to the system operator at the price P_t^R.

The producer maximises profits, 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^M) should be less than or equal to total installed power capacity, that is, the sum of initial capacity (K_0) and investments (K^{inv}):

$$K^M \leq K_0 + K^{inv} \perp \lambda \geq 0, \tag{3}$$

where λ is the shadow price of installed power capacity.[5]

Second, in each period, production of electricity is constrained by the maintained energy capacity, net of the capacity sold as reserve capacity to the system operator. The (net) power capacity is transformed to electric energy production capacity by multiplying by the number of hours in each period (y_t):

$$y_t \leq y_t(K^M - K_t^R) \perp \mu_t \geq 0. \tag{4}$$

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

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

Finally, as mentioned above, a start-up cost is incurred if electricity production varies between day and night (in the same season). This cost depends on the additional capacity that is started in the peak period, that is, on the difference between capacity use in one period and capacity use in the other period in the same season. The start-up capacity (K_t^S) must therefore satisfy the following requirement:

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

[5] In general, the notation $a \leq 0 \perp b \geq 0$ is shorthand for $a \leq 0$ and $b \geq 0$ and $ab = 0$, where *a* is the derivative of the Lagrangian w.r.t. *b*.

where $y_t/\bar{y}_t$ is actual capacity used in period t and $y_u/\bar{y}_u$ is actual capacity used 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).

The Lagrangian of the fossil fuel based power producer is

$$\begin{aligned} L = &\sum_{t \in T} \left(P_t y_t + P_t^R K_t^R\right) - c^{inv} K^{inv} \\ &- \sum_{t \in T} \left(\bar{\nu}_t P^f + c^O\right) y_t - c^M K^M - \sum_{t \in T} c^S K_t^S - \lambda \left\{K^M - K_0 - K^{inv}\right\} \\ &- \sum_{t \in T} \mu_t \left\{y_t - \bar{y}_t \left(K^M - K_t^R\right)\right\} - \eta \left[\sum_{t \in T} y_t - \xi \sum_{t \in T} \bar{y}_t K^M\right] \\ &- \sum_{t \in T} \phi_t \left[\frac{y_t}{\bar{y}_t} - \sum_{u \in T} \delta_{tu}^S \frac{y_u}{\bar{y}_u} - K_t^S\right], \end{aligned} \tag{7}$$

where the selector δ_{tu}^S is equal to 1 for the other period *u* in the same season as period *t*, and 0 for all other periods. It is straight forward to find the first-order conditions (see Aune, Golombek, Kittelsen, Rosendahl and Wolfgang [2001]), and each of these requires, of course, that marginal revenue should be equal to the corresponding marginal costs.

The Lagrangian of the other power producers is quite similar to (7). For pumped storage hydro the only difference is that this producer uses electricity (not fossil fuels) as an input. The reservoir hydro power producer has two additional restrictions in his optimisation problem. First, total use of water, that is, total production of reservoir hydro power in season *s* (y_s^H) plus the reservoir filling at the end of season *s* (F_s) should not exceed total supply of water, that is, the sum of the reservoir filling at the end of the previous season (F_{s-1}) and the seasonal inflow capacity (K_s^I) expressed in energy units:

$$y_s^H + F_s \le F_{s-1} + K_s^I \perp \alpha_s \ge 0. \tag{8}$$

Second, the reservoir filling at the end of each season s cannot exceed the reservoir capacity K^F:

$$F_s \le K^F \perp b_s \ge 0. \tag{9}$$

The waste power producer has one additional restriction, relative to the coal power producer: production in each season should be constrained by the available waste in that season (measured in energy units). For nuclear power, the Lagrangian is similar to (7), except that start-up capacity is exogenously set at zero. This constraint reflects the fact that due to the (prohibitive) costs of starting up and shutting down nuclear power plants, it is not optimal to vary production between day and night. Finally, production of renewables is exogenous.

Fossil fuel supply

In each model country, there is competitive supply of coal, natural gas and oil, represented by upward-sloping supply functions. There is also competitive supply of coal and oil in all the non-model countries.[6] Finally, for each of the non-model countries, net exports of electricity and natural gas to the region of the model countries are set equal to the observed values in the data year of the model.

Energy demand

In each model country, the two end-user sectors (households 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 (see Figure 1). This functional form ensures global fulfilment of regularity conditions derived from economic theory, which is important when modelling institutional changes that may result in large price movements outside the observed range of prices. 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.

Figure 1

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.

Let x_T^D be the utility level, i.e. the quantity of the top node in the CES utility tree. Each node o in the CES utility tree is either a nest k or a commodity c. In a multilevel CES tree a nest can comprise both commodities and subnests, which collectively can be termed goods g, and the top node 'T' is the only nest that is not also a good. Each nest is a function of its goods, with one substitution parameter s_k^D and a share parameter a_g^D for each good :

$$x_k^D = \left[\sum_g a_g^{D\frac{1}{\sigma_k^D}} x_g^{D\frac{1-\sigma_k^D}{\sigma_k^D}} \right]^{\frac{\sigma_k^D}{1-\sigma_k^D}} \tag{10}$$

The chosen nest structure allows possibilities for substitution between electricity at day and night in each season, and between seasons. Each energy good enters into a (generally complementary) nest with energy-using goods such as stoves, ovens, heaters, appliances etc. These energy nests have substitution possibilities within a general energy nest R, which in turn enters into the top nest along with a general commodity P.

Since CES utility functions have unitary income elasticities for the quantity of the goods, final demand for the annual energy commodities (x^f) and period electricity commodities (x_t^E) are modelled as the quantity of goods minus an initial endowment:

$$x^f = x_c^D - \overline{x}_c^D \tag{11}$$

$$x_t^E = x_c^D - \overline{x}_c^D \tag{12}$$

[6] Assuming low cross-price elasticities, we do not model the markets for electricity and natural gas in the non-model countries.

In (11) and (12) $\bar{x}_c^D$ is a demand endowment parameter, facilitating a non-unitary income elasticity of final demand.

The private consumer is assumed to maximize utility, given a budget constraint on final demand reflecting income (V^D) and commodity prices (p_c^D),

$$\mathrm{Max}_{x_k^K} \; x_{\mathrm{T}}^D, \; s.t. \; \sum_c p_c^D (x_c^D - \bar{x}_c^D) \le V^D \tag{13}$$

Using the nest function (10), we obtain an indirect utility function

$$x_{\mathrm{T}}^D = \left(V^D + \sum_c P_c^D \bar{x}_c^D \right) \Big/ p_{\mathrm{T}}^{\mathrm{D}} \, , \tag{14}$$

which is simply the total income (exogenous income plus value of endowment), divided by the top level price index. Each nest price index is of the general form

$$p_k^D = \left[\sum_g a_g^D P_g^{D^{1-\sigma_k^D}} \right]^{\frac{1}{1-\sigma_k^D}} \tag{15}$$

which, together with the final demand prices of model commodities and exogenous commodities (not specified here, see Aune, Golombek, Kittelsen, Rosendahl and Wolfgang [2001]), determine all node prices. The quantity levels of goods are then given by

$$x_g^D = a_g^D \left[\frac{P_k^D}{P_g^D} \right]^{\sigma_k^D} x_k^D \tag{16}$$

which, together with the top level quantity (i.e. utility) from (14), and endowment correction in (11) and (12), determine final demand. In addition to final demand, electricity producers represent intermediate demand. Based on Shephard’s lemma, demand from the electricity production sectors, conditional on a given output level, is the derivative of the cost function (1) with respect to the input price. Hence, demand for fossil fuel f as an input is given by

$$x^G = \frac{\partial C}{\partial P^f} = \sum_{t \in T} \eta_t y_t \tag{17}$$

Since input usage is in a fixed proportion to production, these conditional input demand functions are not directly dependent on the input price, through the optimal production level.

Finally, in each country there is a system operator who, if necessary, will demand reserve capacity to ensure the stability of the electricity system. The price of reserve power P_t^R, see (2), is determined so that there is always a reserve power capacity in each period, that is, a percentage ρ_t of maintained capacity. The demand for reserve power is the result of a social optimisation problem not modelled here, and the price enters complementary to the reserve capacity constraint so that it will only be positive if the constraint is binding:

$$\rho_t \sum_l y_t K_l^M \leq \sum_l K_{tl}^R \perp P_t^R \geq 0 \tag{18}$$

where l runs over all power technologies.

<u>Trade</u>

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 are transported from the world market to the central node, at a given cost. Electricity and gas are traded via international transmission lines and gas pipelines that run between the nodes.

Each transmission line is owned by one agent. Focusing first on natural gas, let m and n be two countries, and let z_{mn}^G be the gas exported from m to n, measured at the node of the importing country n. Because there is some loss in transmission, the quantity z_{mn}^G / θ_{mn}^G is exported from country m. The pipeline owner, who, being a price taker, transports electricity (gas) as long as there is a positive difference between (i) the purchasing price in the import country, P_n^G, and (ii) the loss-adjusted purchasing value in the exporting country, P_m^G/θ_{mn}^G, less of exogenous costs of transmission, c_{mn}^G. Hence, all arbitrage possibilities are exploited. The pipeline can be used either for imports to country n from country m, or for exports from country n to country m. In addition, the owner can expand the initial capacity of the pipeline, $K_{mn}^{G_0}$, through investments, $Kinv_{mn}^G$. Hence, profits of the owner of the pipeline between country m and n are:

$$\Pi_{mn}^{ZG} = \left[P_n^G - \frac{P_m^G}{\theta_{mn}^G} - c_{mn}^G\right]\zeta_{mn}^G + \left[P_m^G - \frac{P_n^G}{\theta_{nm}^G} - c_{nm}^G\right]\zeta_{nm}^G - ckg_{mn}Kinv_{mn}^G, \tag{19}$$

where ckg_{mn} is the annualised (unit) capital cost for expansion of natural gas transmission lines. Moreover, the owner faces the constraint

$$\zeta_{mn}^G - \zeta_{nm}^G \leq K_{mn}^{G_0} + Kinv_{mn}^G \perp \mu_{mn}^G \geq 0, \tag{20}$$

that is, net trade cannot exceed total pipeline capacity. The shadow price μ_{mn}^G can be interpreted as the tariff (in excess of c_{mn}^G) that ensures that demand for transport services does not exceed available capacity. Note that (20) is valid for trade between m and n in both directions (two inequalities). Because investments increase capacity in both directions, the FOC for investment in transmission is given by

$$ckg_{mn} \geq \mu_{mn}^G + \mu_{nm}^G \perp Kinv_{mn}^G \geq 0 \tag{21}$$

that is, capital costs should be compared with two shadow prices (one for each direction), of which at most one can be positive in any equilibrium. Finally, international transportation of electricity is modelled in the same way as for natural gas, except that there is trade in electricity in four time periods.[7]

Equilibrium

For each model country, and each of the three fossil fuels, total quantities consumed are (less than or) equal to total quantities delivered at the central nodes (minus a fixed proportion of 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 than or) equal to total supply.

[7] The FOC for investment in electricity transmission line is thus $cke_{mn} \geq \sum_{t \in T} \psi_t (\mu^E_{mnt} + \mu^E_{nmt}) \perp Kinv^E_{mn} \geq 0$, where cke_{mn} is the annualized (unit) capital cost for expansion of the electricity transmission line.

3 Data

In each model country, demand is divided into two end-user groups: households and industry. In addition to private households themselves, the first group also includes the public sector, services and agriculture, while the second covers both the manufacturing and transport sectors. The data are derived primarily from statistics published by international organisations like OECD, UNIPEDE, UCPTE and NORDEL, but they had to be supplemented with national sources. Several cost parameters build on Golombek, Gjelsvik and Rosendahl (1995) and Amundsen and Tjøtta (1997), whereas price elasticities are drawn from three econometric studies: the SEEM model (Brubakk et al., 1995), the E3ME model (Barker, 1998) and Franzen and Sterner (1995).

The estimated price elasticities in the sources diverged quite substantially, both across countries and sources, with some own price elasticities well over unity in absolute value. The extreme estimates found in the literature were dampened first by averaging across sources, and second by averaging between long and short-run estimated elasticities. The own price elasticities used in the model, which differ across countries, fuels and end-users, are in the range –0.3 to –0.8, with higher values for industry than for households, and higher values for electricity than for fossil fuels.

The fuel efficiencies of the initial power plants were estimated (see Aune, Golombek, Kittelsen and Rosendahl [2001]). For 'new' gas power, coal power, oil power and nuclear power, that is, power plants that might be set up in the future, we assume that all agents are in a position to invest in the most efficient technology. Furthermore, relying on the theorem of factor price equalization in the long run, capital costs and O&M costs are assumed not to differ among the model countries. Efficiencies and costs are in general taken from *Projected costs of generating electricity*, *update 1998* (IEA 1998). For new pumped storage we assume constant efficiency within each country, but these efficiencies differ across countries due, for example, to topographical differences. For each model country, the efficiency for new pumped storage is set equal to the observed efficiency of the initial capacity.

Turning to new reservoir hydro, we use UNIPEDE (1997) for investment costs in run-of-river, pondage, and reservoir plants. Due to the limited availability of precipitation and reservoir potential, there will be increasing long-run marginal costs as the least costly lakes, rivers and waterfalls are exploited first. Long-run marginal costs are represented by calibrated exponential functions, where the starting point of each function (cost of the cheapest project) reflects the mix of run-of-river, pondage, and reservoir plants in that country. For a detailed description of the data and principles behind the calibration of the model, (see Aune, Golombek, Kittelsen, Rosendahl and Wolfgang [2001]).

4 Equilibrium

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). With 13 model countries – Austria, Belgium including Luxembourg, Denmark, Finland, France, Germany, Great Britain, Italy, Netherlands, Norway, Spain, Sweden and Switzerland – the base case equilibrium was obtained after about 5,000 iterations. Below we focus on the case in which it is not feasible – due to political constraints – to invest in nuclear power. The opposite case is dealt with in Section 5.

Price effects

Radical liberalisation of the electricity and natural gas markets in Western Europe pushes down the average prices significantly. By transforming non-competitive national markets with limited international trade into efficient well-integrated international markets, all price differences of a good now reflect cost differences and tax differences only. After the liberalisation (the base case equilibrium), the average end-user price of electricity (weighted over periods, sectors and countries) is 54 USD/MWh, that is, 54 per cent lower than in the base year 1996 (see Table 1, first column).[8] The absolute drop in the household price (90 USD/MWh) is more than twice the drop in the industry price. However, as seen from Table 1 the relative drop is only somewhat higher for households (57 per cent) than for industry (47 per cent), which reflects that in 1996, the household price was much higher than the industry price (due to price discrimination, higher costs of distribution and higher taxes).

[8] The percentage changes in Table 1 are calculated using the weights from the data year. If the average equilibrium price for a sector is lower than in the data year, the figures in Table 1 will underestimate the relative changes. The reason is that the effect of higher consumption of those agents that have experienced the largest price drop is not accounted for. This is a well known index problem.

Table 1 Percentage changes in user prices of electricity and natural gas relative to 1996.

Aggregate annual end-user price	Long run Endogenous gas extraction Endogenous power production Investments, except in nuclear power	Short run Exogenous gas extraction Endogenous power production No investments
Electricity		
Households	-57	-54
Industry	-47	-41
Power		
Total	-54	-50
Natural gas		
Households	-28	-27
Industry	1	3
Gas power	7	9
Total	-20	-18

The weighted average producer price of electricity is 33 USD/MWh. We find the lowest producer prices in Norway, Spain and Sweden (around 30 USD/MWh), and the highest producer prices in Austria, Italy and Switzerland (around 37 USD/MWh). Prices also vary over season and between day and night, partly because demand varies, but also due to costs of production. First, increased electricity supply requires that less efficient plants, and/or inferior technologies, are phased in. Moreover, if a plant is producing during the day, costs will increase if the plant does not produce during the night because the plant will then incur a start-up cost. While the start-up cost component tends to smooth out production from a plant over the day, smooth production combined with high demand during the day and low demand at night will lead to increased price variation between day and night.

In equilibrium, the aggregate producer price is almost 30 per cent higher during the day than at night, whereas the aggregate producer price is only 3 per cent higher in summer than in winter. In Norway, where reservoir hydro power has a substantial market share, period prices are equal except for winter day. In Sweden (which has a relatively large amount of hydro power) and its neighbouring country Finland, prices do not differ in the summer. For all other countries, prices differ across all four time periods.

The average natural gas price decreases as well due to the radical liberalisation. The average end-user price of natural gas (weighted over countries and sectors) is 250 USD/toe, which is 20 per cent lower than in the data year of the model (see Table 1). We see from Table 1 that while the household price drops, the price for industry is almost unchanged, whereas the price for gas power production increases (by 7 per cent).

In general, the price changes reported in Table 1 can be decomposed into three effects;

i) *Removal of price discrimination.* For a given level of sales, quantities will be redistributed between the users so that in equilibrium, all agents pay the same net price (gross price corrected for all cost differences). Note that this effect also captures lower tariffs for transport and distribution in equilibrium than observed in the data year.

ii) *Increased sales.* If sales are increased, for example due to elimination of market power, the average price has to decrease in order to make users willing to buy more energy.

iii) *General equilibrium effects*. If the price of an energy good decreases, end-user demand for all other energy goods falls, and hence the price of all other energy goods drops. Similarly, if the (producer) price of electricity drops, demand for fossil fuels from power plants decreases, and hence fossil fuel prices decrease.

In a strict sense it is not possible to separate the general equilibrium effect from the two other effects because all markets are well integrated. However, if we 'integrate' the general equilibrium effect into the two other effects we can identify the 'gross effect' of eliminating price discrimination (the partial effect of no price discrimination adjusted for some general equilibrium effects) and the 'gross effect' of increased sales (the partial effect of increased sales adjusted for some general equilibrium effects). The gross effect of price discrimination can be identified by a) imposing a tax on producers of electricity that ensures that total equilibrium power production is equal to total power production in the data year (henceforth termed 'exogenous total power production'), and b) imposing that in each model country extraction of natural gas is equal to the data year value (henceforth termed 'exogenous gas extraction').

Table 2 reports the results of identifying the gross price effects. The table shows the percentage changes in user prices relative to 1996. We see that the gross effect of eliminating price discrimination for *both* electricity and natural gas ('exogenous total power production' combined with 'exogenous gas extraction') is a drop in the price of electricity by 9.9 per cent relative to 1996, whereas the price of natural gas decreases by 23.8 per cent relative to 1996. Recall that the *total* effect of the liberalisation is a drop by 54 per cent and 20 per cent for the price of electricity and natural gas, respectively (see Table 1).

As seen from Table 2, the sole effect of increased sales of natural gas can be measured in two ways. First, for exogenous total electricity production the effect of increased extraction of natural gas amounts to a drop in the user price of natural gas (relative to 1996) from 23.8 per cent to 27.5 per cent. Second, with endogenous electricity production the effect corresponds to a decrease in the user price of natural gas from 17 per cent to 20 per cent. Similarly, the partial effect of increased sales of electricity is a drop in the user price of electricity (relative to 1996) from 9.9 per cent to 54 per cent if gas extraction is exogenous, or a drop from 10 per cent to 54.4 per cent if gas extraction is endogenous.

A shift from exogenous total electricity production (in which all power producers face a tax, see above) to endogenous electricity production leads to increased power production, lower user price of electricity, but higher producer price of electricity (due to removal of the tax). Due to lower user price of electricity, end-user demand for gas decreases, which lowers the user price of natural gas, all else being equal. On the other hand, when faced with a higher producer price of electricity, power producers demand more fossil fuels, and hence, cet. par., the price of natural gas increases. In our model there is more inter-fuel substitution in electricity supply than among the end-users, and hence a shift from exogenous total electricity production to endogenous electricity production raises the price of natural gas (see Table 2). This is why the price of natural gas under exogenous gas extraction and exogenous total electricity production decreases more relative to 1996 (23.8 per cent) than under endogenous gas extraction and endogenous electricity production (20 per cent). One should therefore remember that the price differences between these two states are the gross effect of increased sales of *both* electricity and natural gas.

Table 2 Percentage changes in user prices of electricity and natural gas relative to 1996.

	Exogenous total electricity production		Endogenous electricity production	
	Electricity price	Gas price	Electricity price	Gas price
Exogenous gas extraction	-9.9	-23.8	-54.0	-16.9
Endogenous gas extraction	-10	-27.5	-54.4	-19.6

The price effects can alternatively be decomposed into short-run effects and long-run effects. In our model the main difference between short run and long run is that all capacities are given in the short run (capacities in power production, international transmission of natural gas and international transmission of electricity), whereas these capacities are determined by profitability in the long run. Moreover, the (absolute) value of all demand and supply elasticities are highest in the long-run model. In particular, the short-run supply elasticities for natural gas are zero (that is, given extraction) due to the currently existing long-term contracts in the Western European natural gas market.

As seen from Table 1, the differences in the average price reductions between the short run and long run are rather small. While the end-user electricity price drops by 50 per cent in the short run, the corresponding reduction in the long run is 54 per cent. Furthermore, the end-user price of natural gas drops by 18 per cent in the short run, and by 20 per cent in the long run.

Electricity: Production, investment, consumption and trade

The moderate differences in average prices between the short run and the long run conceal a large increase in the consumption of electricity due to greater demand elasticities in the long run. A radical liberalisation also leads to substantial changes at the sectoral level. Table 3 contains information on marginal efficiency and rate of capacity utilisation for thermal power plants that were installed in the data year of the model or earlier ('old plants'). The table provides information on both estimated values for the data year and the equilibrium values after the radical liberalisation.

As seen from Table 3, old oil power production is phased out in several countries. For old gas power, in some countries (Austria, France, Germany, Italy, Spain and Sweden) production is essentially phased out, in Belgium the rate of capacity utilisation drops, whereas in the remaining countries the rate of capacity utilisation increases. Thus for the latter group production increases and marginal efficiency drops. The rate of capacity utilization for coal power increases in all countries, and reaches 90 per cent in several countries.[9]

[9] We have imposed 10 per cent downtime for all fossil fuel plants.

Table 3 Marginal efficiency and rate of capacity utilization for old thermal power plants. Estimated 1996 values in parentheses.

	Gas power		Coal power		Oil power	
	Efficiency	Capacity	Efficiency	Capacity	Efficiency	Capacity
Austria	0.47 (0.35)	0.03 (0.33)	0.34 (0.35)	0.41 (0.39)	(0.27)	0 (0.26)
Belgium	0.41 (0.39)	0.30 (0.38)	0.31 (0.33)	0.90 (0.63)	0.42 (0.47)	0.33 (0.15)
Denmark	0.58 (0.61)	0.90 (0.41)	0.40 (0.41)	0.90 (0.69)	(0.37)	0 (0.32)
Finland	0.54 (0.57)	0.90 (0.56)	0.37 (0.40)	0.90 (0.49)	(0.42)	0 (0.13)
France	(0.52)	0 (0.52)	0.28 (0.33)	0.90 (0.32)	0.38 (0.47)	0.27 (0.08)
Germany	(0.35)	0 (0.30)	0.30 (0.32)	0.90 (0.67)	(0.40)	0 (0.10)
Great Britain	0.42 (0.43)	0.84 (0.71)	0.34 (0.37)	0.90 (0.47)	(0.30)	0 (0.24)
Italy	(0.37)	0 (0.26)	0.29 (0.33)	0.63 (0.35)	(0.37)	0 (0.78)
Netherlands	0.44 (0.48)	0.67 (0.35)	0.31 (0.33)	0.90 (0.74)		
Spain	0.54 (0.55)	0.04 (0.23)	0.32 (0.33)	0.90 (0.59)	(0.39)	0 (0.18)
Sweden	(0.48)	0 (0.19)	0.40 (0.42)	0.85 (0.66)	(0.39)	0 (0.16)

As seen from Table 3, marginal efficiency of plants using the same technology varied significantly between countries in the data year. The differences reflect cost differences in power production as well as market imperfections and energy policies in the model countries in 1996. However, marginal efficiencies also differ after liberalisation: the equilibrium condition with respect to power production does not require that marginal efficiency should be equal across plants, technologies and countries. Maximising (7) with respect to produced electricity gives

$$P_t - \nu_t P^f - c^0 - \mu_t - \eta - \left(\phi_t / y_t - \sum_{u \in T} \delta_{tu}^S \phi_u / y_u \right) \leq 0 \perp y_t \geq 0 \qquad (22)$$

where $\nu_t = \frac{\partial(\bar{\nu}_t y_t)}{\partial y_t}$ 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 ($\nu_t P^f + c^0$) should be equal to the sum of several (country specific) shadow prices. These are the shadow price of the periodic energy capacity (μ_t), the shadow price of the annual energy capacity (η), and the difference (measured per hour) between the shadow price of capacity used in this period (f_t / y_t) and in the other period in the same season (f_u / y_u). Hence, marginal efficiency is only one factor that determines production of power.

Turning to 'new' power production, there is substantial investment in, and thus production of, (new) gas power in Belgium. There is also investment in gas power in Great Britain, whereas in France, Germany and Spain there is investment in coal power. There is no investment in oil power, however; see Section 5 for a discussion on investments relative to plant efficiency. The observation that investments in power production are undertaken only in some countries partly reflects our assumption that all agents are in a position to invest (unlimited) in the most efficient technology without any costs of adjustment. Thus the long-run unit cost of production differs between countries only due to differences in the price of fossil fuels. In our model differences in fossil fuel prices are due to country differences in costs of transport, distribution and taxes. The investment pattern also reflects differences in costs of transporting energy goods internationally, that is, whether it is cheaper to transport, for example, natural gas than gas power between the model countries.

Table 4 shows production of electricity by different technologies for the sum of the 13 model countries. Total electricity supply increases by 50 per cent relative to 1996. Almost 80 per cent of the increase is due to production in new plants, mainly coal power plants. In equilibrium, 540 TWh is produced in new coal power plants, whereas production in old coal power plants increases by 390 TWh. The total market share of coal power increases from 27 per cent to 44 per cent.

There is a small reduction in production in old gas power plants. However, due to investments in new gas power, total gas power production increases by so much that its market share increases (from 12 per cent to 18 per cent). Table 4 shows a small increase in reservoir hydro (by 5 per cent), but this is due to more precipitation in equilibrium (defined as a normal hydrological year) than in the data year. On the other hand, production in initially existing oil power plants is almost phased out (see discussion above), and there is no investment in new oil power. Pumped storage hydro is completely phased out, which reflects a smaller price difference between day and night in equilibrium than in the data year. Finally, the increase in nuclear power is due to technical constraints.[10] In equilibrium, nuclear power has the second largest market share (24 per cent).

Table 4 Supply of electricity from different technologies for the sum of the model countries (TWh). Market shares in parentheses.

	1996	Long run	Short run
Gas power	306 (0.12)	255 (0.07)	341 (0.12)
New gas power		386 (0.11)	
Coal power	674 (0.27)	1061 (0.29)	1060 (0.36)
New coal power		537 (0.15)	
Oil power	176 (0.07)	29 (0.01)	207 (0.07)
New oil power			
Reservoir hydro	398 (0.16)	419 (0.12)	419 (0.14)
New reservoir hydro		17	
Pumped hydro	22 (0.01)		5
New reservoir hydro			
Nuclear power	829 (0.34)	871 (0.24)	871 (0.29)
Waste power	42 (0.02)	42 (0.01)	42 (0.01)
Renewables	9	9	9
Sum	2456	3629	2955

Consumption of electricity drops in Norway, but increases in all other countries. For each type of end-user, total consumption (aggregated over countries) increases in each time period. The increase is greatest on winter nights (53 and 70 per cent for households and industry, respectively), whereas the increase is smallest on winter days (around 35 per cent for each end-user group). Total consumption of electricity (aggregated over countries, sectors and periods) is 3375 TWh, which differs from

[10] Because nuclear power is typically run as base-load in most countries, in the calibration we have assumed that actual downtime in 1996 reflects maintenance and upgrading only. The exception is France, which in 1996 had a capacity utilisation of 0.76. Hence, production was probably restricted also due to low base-load demand relative to the domestic nuclear power capacity. For France we have therefore imposed the average rate of capacity utilisation (0.84).

total production (3629 TWh, see Table 4) due to losses in transport and distribution, and a small amount of net imports (from non-model countries).

The liberalisation raises gross trade in electricity among the model countries from 180 TWh (1996) to 784 TWh. In order to calculate gross trade we have summed over all trade movements. However, some countries re-export part of their imports: if country A exports 2 kWh to country B, which re-exports 1 kWh to country C, then gross trade amounts to 3 kWh, although the 'correct' number should be 2 kWh. In order to avoid this double counting we first calculate net imports of electricity for each model country (consumption minus domestic extraction), and then sum over all countries with positive net imports. For the data year this aggregated figure is 94 TWh, whereas in equilibrium the corresponding number is 653 TWh, that is, about 20 per cent of total consumption of electricity.

The radical increase in gross trade implies that some countries become large importers, whereas others become large net exporters. France, being the largest net exporter of electricity in 1996, increases its exports from 69 TWh (1996) to 359 TWh (see Table 5). The increase reflects greater coal power production (see discussion above). Belgium also becomes a large exporter of electricity (due to more gas power production, see discussion above), whereas Denmark and Norway are 'small' exporters of power (30-40 TWh).

Italy becomes the largest importer of electricity (302 TWh) due to decreased domestic production (gas power and oil power is phased out, see Table 3). Italy imports electricity mainly from France, and most of the imports are transported through a new transmission line (35 GW capacity). In Germany, a small net export in 1996 is turned into a significant net import (267 TWh), which reflects lower user prices (higher consumption) and a modest increase in domestic electricity production. Germany imports power from several countries (Belgium, Denmark, France, Netherlands, Switzerland and Sweden), and a significant share of the imports is transported through a new transmission line from Belgium.

Table 5 Net imports of electricity and natural gas. 1996 values in parentheses

	Electricity (TWh)	Natural Gas (mtoe)
Austria	33 (2)	4 (6)
Belgium	-229 (6)	66 (14)
Denmark	-23 (-12)	3 (-2)
Finland	13 (4)	4 (3)
France	-359 (-69)	30 (32)
Germany	267 (-8)	48 (68)
Great Britain	0 (17)	-5 (1)
Italy	302 (28)	25 (34)
Netherlands	5 (16)	-24 (-34)
Norway	-24 (1)	-65 (-38)
Spain	-14 (1)	8 (9)
Sweden	18 (9)	1 (1)
Switzerland	13 (-1)	2 (3)

Natural gas: Extraction, consumption and trade

Turning to natural gas, in the model we use long-run supply functions for gas extraction. For the major suppliers (Netherlands, Norway and Great Britain) these functions are calibrated using micro information, (see Aune, Golombek, Kittelsen, Rosendahl and Wolfgang [2001]). For the remaining countries, all supply elasticities are set equal to 1 (see Golombek and Bråten [1994]). Extraction of natural gas increases by 50 mtoe relative to 1996 (15 per cent). We find the largest increases in Norway (35 mtoe) and Great Britain (15 mtoe).

Note that there are two counteractive effects on natural gas extraction from the major suppliers. While elimination of the non-competitive market structure in the data year should increase total output, a lower price of electricity tends to lower the demand for natural gas, and hence decrease output. In our model, the direct effect on supply (enhanced competition) dominates the indirect effect (inter-fuel substitution). For the remaining suppliers, only the indirect effect is at work, and hence from these countries extraction decreases.

Table 6 shows how natural gas (and other energy goods) are distributed between different sectors. Prior to liberalisation almost 50 per cent of the natural gas was used in the household sector, whereas manufacturing used around one-third and power production one-fifth of the available amount of natural gas. After liberalisation the use of natural gas in power production increases by 45 mtoe, which reflects the significant increase in gas power production (see discussion above). Consumption in the household sector increases by around 11 mtoe, whereas the use of natural gas in manufacturing decreases slightly. The difference reflects that due to elimination of price discrimination the household price has decreased much more than the manufacturing price (see Table 1), which, cet. par., implies redistribution of the natural gas quantities in favour of households. However, because total available amount of natural gas has increased by 50 mtoe (see above), the shares of both households and manufacturing decrease (see Table 6).

Table 6 Distribution of energy between sectors (per cent). 1996 values in parentheses

	Household	Manufacturing	Power production
Electricity	53 (54)	47 (45)	0 (1)
Natural gas	44 (48)	26 (32)	30 (20)
Coal	2 (4)	12 (23)	86 (73)
Oil	18 (18)	81 (76)	1 (6)

In 1996 gross trade in natural gas between the model countries, including net imports from external countries, was 180 mtoe, whereas in equilibrium gross trade is 235 mtoe. As pointed out above one should instead use net imports (summed over all model countries with positive net imports) as a measure for the amount of trade. With this measure, trade in natural gas increases from 170 mtoe in 1996 to 191 mtoe in equilibrium. Hence, in equilibrium trade in natural gas amounts to slightly more than 50 per cent of consumption.

There are almost no investments in new transmission pipelines. The main exception is Norway, which builds a small pipe to Denmark. In Denmark, most of the increased imports from Norway are re-exported to Sweden, which now sets up a small pipeline to Finland. Thus in equilibrium Finland imports natural gas from both Sweden and Russia.

Oil and coal

The world market prices of oil and coal are only modestly affected, which primarily reflects that the 13 model countries have only a small share of world consumption. The price of oil decreases by 1 per cent, which reflects lower end-user demand for oil (due to lower prices of electricity and natural gas) and a radical decrease in oil power production. On the other hand, the price of coal increases by 2 per cent. Increased use of coal in power production tends to raise total demand for coal, and this effect dominates lower end-user demand for coal (due to lower prices of electricity and natural gas).

With lower prices of electricity and natural gas, end-user demand for oil is reduced, although only slightly. The (absolute) decrease in oil consumption is greater for oil power production than for the end-users. Because oil power in addition had the lowest initial consumption of oil, the share of oil consumption used in oil power production is reduced (see Table 6). End-user consumption of coal decreases slightly, whereas the use of coal in power production is more than doubled (158 mtoe in 1996 versus 407 mtoe in equilibrium). Hence, the share of coal consumption used in coal power plants increases (see Table 6).

5 Robustness

In the previous section we described the equilibrium outcome, including investments in new power capacities, under a set of central assumptions. Some of these are subject to substantial uncertainty, and it is of interest to see how robust the results are if certain assumptions are changed. In this section we first discuss impacts of increased imports of natural gas. Second, effects of changing the efficiency assumptions for new thermal power plants are analysed. Finally, we study how the equilibrium changes if investments in nuclear power are feasible.

Imports of natural gas

In the base case equilibrium, net imports of natural gas and electricity to the region of the model countries are equal to the observed 1996 values. In particular, the import of natural gas from Russia is 60.5 mtoe. Russia, which has around one-third of the world's total proven gas reserves, extracted around 600 mtoe in the mid-1990s. Domestic consumption amounted to around 400 mtoe, and Russia exported natural gas to Western Europe, Eastern Europe and the FSU (Ukraine, Belarus, etc.).

In the first set of robustness scenarios, we increase imports from Russia from 60.5 mtoe to 160.5 mtoe: see Figure 2, where the values of the producer price of natural gas and the market share of gas power have been set to 100 when Russia exports 60.5 mtoe (the base case equilibrium).[11] As seen from Figure 2, increased import of natural gas lowers the aggregate producer price of natural gas. Compared with the base case, increased imports of 100 mtoe lead to a reduction in the aggregate producer price of gas by 17 per cent. A lower producer price of natural gas tends to decrease extraction in the model countries. In our model total extraction in the model countries decreases by around 18 mtoe when imports from Russia increase by 100 mtoe, that is, the net increase amounts to 82 mtoe natural gas.

Figure 2

[11] We do not analyse whether such an increase is profitable for Russia, and we assume that there are no bottlenecks in the transport of Russian gas to Western Europe.

Consumption of natural gas in the household and industry sectors increases by 5 mtoe and 8 mtoe, respectively. Hence, most of the additional natural gas (69 mtoe) is used in power production. The supply of (old and new) gas power increases by 450 TWh, and the market share of (old and new) gas power increases from 18 per cent to 29 per cent, which is an increase of about 60 per cent (see Figure 2). Because total supply of electricity increases by 2 per cent, the price of electricity drops, and production of (primarily new) coal power is reduced by around 55 per cent.

Plant efficiency

As mentioned in Section 3, in general our assumptions of costs and fuel efficiency for new thermal power plants are taken from the IEA publication *Projected costs of generating electricity*, *update 1998.* This source builds on information received from the member countries on technologies and plant types that could be commissioned by 2005-2010, and therefore could be ready for electricity supply before 2010. Table 7 shows our key figures under the assumption that the real rate of interest is 7 per cent. Note that the IEA source does not contain any information on oil power; we had to go back to the 1987 edition (plants to be commissioned in 1995) in order to find costs and efficiency for ('new') oil power. The lack of recent information on oil power reflects limited R&D on this technology over the last 15 years.

Table 7 New power plants. Costs (1996 US dollars) and efficiency.

	Coal power	Gas power	Oil power	Nuclear power
Cost of investment (MUSD/GW)	115.4	71.0	120.4	157
O&M (MUSD/TWh)	6.8	4.3	8.4	6.8
Fuel (MUSD/TWh)				8.1
Efficiency (%)	48	57	52.2	

In order to test the robustness of the equilibrium we now increase the efficiencies of new thermal power plants. In separate runs of the model we first increase the efficiency of new gas power from 57 per cent (the base case) to 58 per cent, then from 58 to 59 per cent, and so on until the initial efficiency has increased by 10 percentage points. Next, we undertake the same exercise for new coal power, new oil power and finally for all the three types of technologies together.

Improved efficiency increases total supply of electricity. Hence, equilibrium electricity production increases and the price of electricity drops. The detailed picture is, however, more complex. First, improved efficiency of, for example, new gas power lowers unit costs of production for this type of technology. Because the competitive position of new gas power has improved, investments in gas power increase, whereas investments in other types of thermal power production decrease. Total new capacity increases, which tends to increase total output. Thus the price of electricity falls and part of the old thermal power production is crowded out.

Although total output increases, in some of the four electricity market periods equilibrium production may decrease. Under our assumptions new gas power has lower start-up costs than other thermal power technologies. Because price during the day is higher than at night (see above), new gas power producers tend – relative to phased-out coal power producers – to increase supply more during the day, and thus lower production more at night. The effect is, cet. par., a reduced difference between the price during the day and at night, and lower aggregate equilibrium production at night. The latter effect may dominate the general increase in total electricity production.

As seen from Figure 3, increased efficiency for new gas power leads to a higher market share for this type of plant. If the efficiency increases by 10 percentage points, the market share for new gas power increases from 11 to 20 per cent, whereas the market share for new coal power decreases from 15 to 11 per cent. There is no effect on new oil power as there is no investment in this type of technology in the base case equilibrium (see Section 4). If instead the efficiency of new coal power increases by 10 percentage points, the market share of new coal power increases from 15 to 23 per cent, whereas new gas power shows a decrease in market share from 11 to 5 per cent.

With an improved efficiency of new gas power by 10 percentage points, the aggregate producer price of electricity decreases by 4 per cent. Total electricity supply increases by 2 per cent, and production of electricity is higher in all four time periods (compared with the base case equilibrium). On the other hand, as we increase the efficiency from 58 per cent to 59 per cent, production during summer nights and winter nights decreases slightly (see discussion above).

When the efficiency of new coal power increases by 10 percentage points, the aggregate producer price of electricity decreases by 7 per cent. This is more than in the case of improved gas power efficiency (4 per cent), which reflects that in the base case equilibrium new coal power has a larger market share than new gas power (15 per cent versus 11 per cent). Finally, if the efficiencies of both new gas power and new coal power increase by 10 percentage points, the combined market share increases (from 26 per cent) to 33 per cent, aggregate producer price decreases by almost 8 per cent and total production of power increases by 4 per cent.

Figure 3

When the efficiency of new oil power is increased by 10 percentage points, there is still no investment in this technology. The efficiency has to increase by as much as 29 percentage points before new oil power is phased in. This result can also be illustrated as follows: according to our data source for oil power (IEA 1987), both investment costs and operation and maintenance costs (O&M) were about 30 per cent lower for 'new' oil power than for 'new' coal power in 1987. If we assume that this was also the case in 1996 (the data year), there will still be no investments in new oil power. Yet if investment costs and O&M costs are 50 per cent lower for new oil power than for new coal power (in 1996), new oil power has a market share of almost 20 per cent in equilibrium.

Nuclear power

We now turn to the case in which investments in new nuclear power are feasible. Again cost estimates are taken from IEA (1998), and the different cost elements are reported in Table 7. In the new equilibrium total production of electricity (3630 TWh) virtually does not differ at all from base case equilibrium. The producer price of electricity is therefore almost unchanged (relative to the base case) and hence old thermal power production changes only marginally (see Figure 4). On the other hand, investments in nuclear power amount to almost 40 GW. The market share of new nuclear power is almost 10 per cent, that is, the total market share of nuclear power is about one-third.

There is – relative to the base case equilibrium – a sharp reduction in investments in, and production of, new coal power (37 GW/294 TWh), whereas new gas power production decreases only slightly. Because investments in nuclear power primarily take place in Austria and Italy, whereas the drop in production of new coal power mostly takes place in France, investments in new transmission lines change. In the base case equilibrium there was an extension of the line between France and Italy (35 GW, see above). This project is now almost abandoned (reduced to 3 GW). Total investments in new pipelines decrease from 67 GW (base case) to 36 GW, and trade in electricity is reduced by roughly one-third.

Figure 4

Finally we study how the equilibrium is affected by cost of investment in nuclear power. When we increase cost of investment by 1 MUSD/GW (from 157 MUSD/GW, see Table 7) new nuclear power production decreases by 4 TWh, and new coal power increases by 3 TWh. However, an increase in investment cost by one more MUSD/GW leads to a radical reduction in nuclear power as production in Italy decreases from 270 to 115 TWh, and further to 0 if the investment cost is increased by anther MUSD/GW. Again, most of the decrease is counteracted by increased new coal power (in France). If we increase investment costs further, no investments in new nuclear power are profitable when costs reach 177 MUSD/GW.

6 Concluding remarks

The purpose of the present paper is to study numerically long-run effects following from a radical liberalisation of the European natural gas and electricity markets. To this end we have constructed a full long-run equilibrium model for the energy markets in Western Europe. In the model all markets are competitive, including national markets for reserve power capacity and markets for transport of energy. The model comprises 13 Western European countries, and in each country there is production and consumption of coal, natural gas, oil and electricity. Moreover, there is trade in all energy goods. Electricity, which can be produced by a number of different technologies in each country, is traded in four period markets (summer vs. winter, day vs. night). There are investments in power capacity as well as investments in (pipe)lines that connect the national (gas) electricity markets in Western Europe.

We find that relative to the data year of the model (1996), a radical liberalisation lowers the aggregate long-run user price of electricity by around 50 per cent, whereas the aggregate long-run user price of natural gas drops by 20 per cent. For natural gas the price decrease primarily reflects the elimination of price discrimination, whereas for the electricity price, increased production is also of significant importance.

Total production of electricity increases by around 50 per cent relative to the data year. Almost 80 per cent of the increase is due to production in new plants, mainly new coal power. Because production in old coal power plants increases as well, the market share of coal increases from 27 per cent to 44 per cent. On the other hand, there is a modest decrease in old gas power production, old oil power is almost phased out and pumped storage hydro is completely phased out. Investments in new power capacities amount to 120 GW, and trade in electricity increases significantly. Note that these results are based on no investments in nuclear power. If nuclear power investments are feasible, new nuclear power crowds out roughly 50 per cent of the new coal power production, whereas total production of electricity is almost unchanged.

The radical liberalisation increases total welfare in the 13 model countries by 44 billion USD, which corresponds to 6 per cent of total energy expenditures for the end-users in the model countries. The consumer surplus of the end-users increases by 197 billion USD, primarily due to increased surplus for the households (151 billion USD). On the other hand, operating surplus decreases by 129 billion USD, primarily due to lower surpluses in the electricity sector (126 billion USD). Further, for the model countries the drop in trade surpluses amounts to 6 billion USD. Finally, the effect on total welfare also reflects decreased tax revenues by 17 billion USD, which is primarily due to lower VAT income (14 billion USD).

As mentioned in the introduction, a radical liberalisation may take many years to implement – if it ever becomes a reality at all. Assuming that the EU does indeed succeed in their liberalisation programme, we conclude this paper by using the model to find the equilibrium outcome for a future year. Because costs of generating electricity for future years are very uncertain, we have restricted the time span to 2010, and hence our base case cost estimates for new power generation should be adequate. As we move from the data year of the model (1996) to 2010, demand from end-users shifts outward due to economic growth, whereas old electricity generating capacities depreciate.

Assuming that investments in nuclear power are not feasible, we find that in 2010 total production of electricity is 100 per cent above the actual 1996 outcome and 30 per cent above the base case equilibrium, which was a hypothetical long-run liberalised equilibrium for 1996. The increase in production mainly reflects increased new coal power production; the total market share of coal power is 70 per cent (46 per cent in the base case equilibrium). Moreover, the average user price of electricity and natural gas is 50 per cent and 10 per cent, respectively, below the 1996 level. Finally, if we increase the rates of depreciation by so much that there is no old thermal power capacity left in 2010, the aggregate user price of electricity is again roughly 50 per cent lower than in 1996, independent of whether nuclear power investments are feasible or not. Hence, a 50 per cent decrease in the user price of electricity seems to be a robust estimate of the long-run effect of a radical market liberalisation in Western Europe.

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