Economic Modelling 35 (2013) 99–111

Contents lists available at ScienceDirect

Economic Modelling

journal homepage: www.elsevier.com/locate/ecmod

Is electricity more important than natural gas? Partial liberalizations of the Western European energy markets

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ARTICLE INFO

Article history:
Accepted 18 June 2013

JEL classification:
C15
C68
Q40
Q48

Keywords:
Energy markets
Liberalization
Price discrimination
Resource rent

ABSTRACT

The European Union has introduced directives that aim to liberalize and integrate electricity and gas markets in Western Europe. While progress has been made, there have also been setbacks, partly because of concerns about national interests and security of supply. This may call for an EU medium-term strategy to implement and enforce liberalizations in only selected parts of the energy industry. We use a numerical model to assess what types of liberalization – electricity vs. natural gas; domestic markets vs. international trade – are most influential in decreasing prices and increasing welfare in Western Europe. As part of identifying effects of different types of liberalizations, we present a method for calibrating the magnitude of deviations from the hypothetical competitive outcome in different parts of the energy industry in Western Europe. We find that a liberalization of electricity markets has greater quantity and welfare effects than a liberalization of gas markets, and that liberalizations of domestic energy markets have (overall) greater effects than liberalizations of trade in energy between Western European countries. Finally, the short-run effects essentially parallel the long-run effects, though they are significantly smaller.

1. Introduction

The gas and electricity industries in Western Europe have long been characterized by inefficiencies and a lack of competition, which are mainly due to legal monopolies in production, natural monopolies in domestic transport and distribution networks, and limited international trade. Consequently, a liberalization – or more precisely a reregulation – of these industries has been on the political agenda for the last couple of decades.

Some of the first reforms were seen in England and Wales around 1990, using unbundling and privatization of supply and distribution of gas and electricity to enhance competition: see, for example, Newbury (2006). Related reforms followed in a number of countries (see Sioshansi and Pfaffenberger, 2006), and the European Union (EU) soon became the major driving force in liberalizing the energy markets of Western Europe: the first proposals and directives appeared in the late 1980s, and a major milestone was reached in the late 1990s with the issuance of updated directives on the establishment of competitive ("internal") markets for electricity and natural gas. Whereas progress has been made,[1] the transition to a single, competitive, Western European market has been partial and incremental.[2] In particular, there have been setbacks due to concerns about national interests and energy security: according to the European Commission's, 2010 benchmark report, in several EU countries the wholesale natural gas market is dominated by a few companies, and there are end-user price regulations in the majority of the EU member states.

It seems reasonable that also future liberalization progress will be partial and incremental, and will continue to face entrenched industrial interests, transnational conflicts of interest, and energy security concerns. If welfare is important to policy makers this calls for prioritized efforts, where sector-specific policies for the Western European energy markets that improve welfare significantly should be identified and implemented first.

In developing the political priorities, we believe that an empirically based model of the Western European energy markets can provide important insights. Such a model allows us to take account of market interactions that make models focusing on smaller areas, for example, a single country, or a single energy carrier, misleading. Similarly, it allows us to distinguish between short-run and long-run effects: initially, policy X may seem better than policy Y, but the effects of X may dampen after a few years by counteracting mechanisms while policy Y may deliver increasing benefits in the long run. Taking such effects into account, in the present paper we

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[1] See, in particular, updated versions of the internal energy market directives: European Parliament (2003a, 2003b).

[2] See, for example, Commission of the European Communities (2005a, 2005b), European Union (2005) and Lohmann (2006).

0264-9993/$ – see front matter
http://dx.doi.org/10.1016/j.econmod.2013.06.023

compare policies that differ in two dimensions: those focusing on liberalization of domestic energy markets versus those that focus on liberalization of energy trade between EU countries, and those focusing on liberalization of electricity versus those focusing on liberalization of natural gas markets.

In order to study numerically different types of liberalization, we have developed a detailed, empirically based, multi-market equilibrium model LIBEMOD MP, in which each Western European country produces, trades and consumes a number of energy goods. Through an extensive calibration procedure we identify "sectoral deviation parameters" that reflect the extent to which factors like regulations and monopolies distort the various energy markets away from the competitive equilibrium. The basic idea of the calibration is described in Section 2. By selectively removing various sets of deviation parameters, we can assess the effects of successfully liberalizing different energy sectors in Western Europe, and trace the consequences this would have for overall efficiency and welfare. While the calibrated values of the deviation parameters are important for the magnitude of the results in this article, identification of the exact sources of distortion is not of importance.

This paper examines different partial liberalizations of the Western European energy markets; domestic markets versus EU trade, and electricity versus gas. For our methodology to be valid the numerical model needs to reflect the basic underlying economic realities. LIBEMOD MP covers Western Europe, that is, all EU members in Western Europe plus the EFTA countries Norway and Switzerland. All Western European countries trade in electricity and gas through transmission lines/pipes, in markets that are non-competitive (prior to the liberalizations), while the markets for coking coal, steam coal and oil are international and competitive. In each model country, electricity can be produced by a number of technologies at heterogeneous plants using various fuels and with differing energy efficiencies. In addition, there is intra-fuel competition between, for example, gas as an input to electricity production and gas as a good demanded by end users. LIBEMOD MP contains a detailed description of electricity producers, who are modeled as profit-maximizers subject to a number of technical constraints. In order to capture the variation in demand for electricity over the year, there is trade in electricity in 12 periods. Sections 3 and 4 give a description of the model and data.

We find in Section 5 that a liberalization of electricity in general has greater quantity and welfare effects than a liberalization of gas, and a liberalization of domestic energy markets has for most variables greater effects than a liberalization of trade in energy between Western European countries. In particular, a liberalization of domestic electricity markets increases production of electricity significantly, leads to a significant redistribution from producers to consumers, and increases total welfare. The liberalization of international trade in energy in Western Europe has only a small impact on quantities and prices, yet the liberalization of international transmission of gas redistributes a huge amount of economic surplus from the transmission companies to the gas resource owners.

The different impacts on natural gas and electricity markets reflect the fact that natural gas is an exhaustible scarce resource and thus has limited scope for increased production in the long run. Therefore, natural gas liberalization has a greater effect on the distribution of surplus than on total welfare. Electricity, however, is a produced commodity and the quantity can be expanded considerably without large unit-cost increases.

We find that the short-run liberalization effects essentially parallel the long-run effects, though they are significantly smaller. Our simulations also suggest that the order of liberalization has only a minor impact on the effects of the partial liberalizations. Finally, Section 6 sums up our main results and provides a short discussion on total welfare effects of Western European energy market liberalization when the impact on emissions of CO_2 is also taken into account.

2. Modeling market imperfections

2.1. Cournot vs. conjectural variation

Traditionally, the natural gas and electricity industries in all Western European countries have been subject to various government regulations and controls. These regulations significantly affected all levels of the industries — extraction, production, import, transport, distribution and prices. The standard approach in economics in modeling market imperfections is to assume a market structure characterized by monopoly, oligopoly or a (cost-minimizing) cartel. Frequently, oligopoly is modeled as a non-cooperative Cournot game: that is, agents choose quantities simultaneously. This leads to an equilibrium in which quantities, and thus also the market price, lie between the competitive outcome and the monopoly solution.

It seems plausible that the present Western European energy market outcome is somewhere between the competitive equilibrium and the monopoly solution. Yet, because of substantial government regulations in the energy industry, there is no particular reason to believe that the outcome is identical to (or even close to) the Cournot solution, which is just one of an infinite number of outcomes between the competitive equilibrium and the monopoly solution. Thus, if the task is to study a policy change – for example, how an imposed energy or environmental tax will affect Western European energy markets – it is implausible that the Cournot model will mimic the real changes. As long as the market structure in Western European energy markets is characterized not only by strategic behavior that tends to lower production (this effect is captured by the Cournot model), but also by factors such as government regulations to protect consumer interests, measures to ensure security of supply, foreign policy considerations, horizontal and vertical integration, as well as international bargaining over the (producer) price of natural gas, application of the Cournot model may provide bad predictions with respect to changes in policy instruments and market structure (e.g., liberalization of energy markets). [3]

In addition, in the energy industry some agents that are buyers in the fuel markets (e.g., the power producers) will be sellers in another market (i.e., the electricity market), and these agents may be large enough to have market power in both markets. It is not obvious how the Cournot conditions should be applied in such a multi-market game, and how one could potentially take account of secondary market feedbacks.

It may also be hard, or not even feasible, to find the equilibrium in a Cournot game. Typically, papers examining Cournot games for energy industries assume that there is a simple demand function/system for a single good: see Golombek and Bråten (1994), Bråten and Golombek (1998), Egging and Gabriel (2006) and Holz et al. (2008). It is then easy to find the first-order conditions for the strategic agents, and these are used to find the equilibrium. In the present paper we have demand from various agents with different behavioral assumptions. For example, some agents demand energy as inputs in electricity production, and these agents are modeled with a set of first-order optimum conditions that are solutions to their own profit-maximization problems, and where corner solutions often appear. The resulting demand system cannot be differentiated, and thus we are not in a position to specify the first-order conditions for Cournot players.

An alternative approach to the Cournot model is to let data determine type and degree of market imperfections. This is possible when applying the theory of conjectural variation, whereby each agent conjectures how an increase in own production would be met by

[3] The energy market structure can be seen as the outcome of interest groups fighting for their own interest and politicians weighing the well-being of different groups. Grossman and Helpman (1994) examines how special-interest groups make political contributions in order to influence their net benefits.

changed production from the competitors. Let $p(\sum x_j)$ be the inverse demand function where $\sum x_j$ is total production, and let x_i be production from agent i. Hence, the income of producer i is $p(\sum x_j)x_i$, and a marginal increase in production from agent i will change his income by $p+\frac{dp}{d(\sum x_j)}\frac{d(\sum x_j)}{dx_i}x_i$. Here, $\frac{d(\sum x_j)}{dx_i}$ is the conjectural derivate: the expected change in total production as a response of a marginal increase in own production. It can be shown, see Varian (1992), that if all agents believe that an increase in own production ($dx_i>0$) will not lead to any response from the competitors ($dx_j=0$ for $j\neq i$), that is, $\frac{d(\sum x_j)}{dx_i}=1$, then the Cournot solution is the outcome. Further, the competitive equilibrium can be shown to be the outcome if all agents believe that an increase in own production ($dx_i>0$) will be exactly counteracted by the competitors $\left(\sum_{j\neq i}dx_j=-dx_i\right)$, that is, $\frac{d(\sum x_j)}{dx_i}=0$. In principle, data can be used to calibrate the sizes of the conjectural variations and hence determine market structure: see, for example, Dixit (1987).

In order to apply the theory of conjectural variation, one must be able to differentiate the inverse demand function $p(\sum x_j)$. However, above we explained that in our model the demand system for electricity producers cannot be differentiated. Below we show that there is a way around this problem, and our method of modeling market imperfections (in electricity production) is closely related to the theory of conjectural variation.

In our numerical model, the market structure initially deviates from perfect competition in the following sectors:

- electricity production;
- domestic electricity retail and gas retail;
- international transmission of electricity and gas.

Below we explain how deviation from perfect competition has been modeled in these sectors. We also explain how we identify the effects of a change in the market structure from a non-competitive outcome to a competitive equilibrium for a sector, that is, the effects of a partial liberalization.

2.2. Market structure — electricity production

Assume that there is perfect competition in production of electricity. Then the difference between (i) the price of electricity obtained by a producer and (ii) the sum of marginal costs of this producer, including shadow values of all capacity constraints, should be zero. Whereas fuel costs do not vary much over the 24-hour cycle, shadow prices do, reflecting shifts in demand. Thus, in peak hours the difference between the price of electricity obtained by the producer and his observable marginal costs (e.g., fuel costs, but not shadow values) will be large. Such an observed difference may therefore be consistent with a competitive outcome. Alternatively, it may reflect some type of deviation from the competitive outcome, for example, market power.[4]

We now explore the latter case. Assume that a competitive electricity market is changed to a cartel. Through tacit collusion the cartel sets the level of production for its members. Suppose we can observe the production level for each cartel member. Although we do not know the rule that distributes the total quantity of production agreed upon between the members of the cartel, we can mimic this behavior: It is well known from economic theory that restrictions facing an agent – for example, a quantity restriction – can, under conditions of no uncertainty and full information, be represented through a set of taxes/subsidies and transfers in a model of perfect competition. Hence, if we have an adequate model of the (hypothetical) competitive case, we can mimic the cartel by including taxes/subsidies and lump-sum transfers in the model. The taxes/subsidies and lump-sum transfers are calibrate by comparing (i) the observed outcome with (ii) the prediction of the model without taxes/subsidies and lump-sum transfers.

Here is a simple example. Suppose that marginal cost of production of electricity is increasing, has no jumps and that there are no capacity constraints in electricity production (some of these assumptions will be relaxed later). Fig. 1 then shows the marginal cost function for one cartel member. A cartel member could be a single producer or a group of producers where each producer (plant) has a thermal efficiency that differs from the other producers (plants) in the group because of, for example, a distinct vintage.

Under perfect competition we know that the producer(s) in Fig. 1 should supply x_0 when facing the electricity price p_0. Under a cartel agreement, production will typically differ from x_0. If we observe that production is lower, say, x_1, this can be mimicked by a unit tax t_1 on production, that is, *as if* this cartel member pays the cartel t_1 for each unit it produces (total tax payment is t_1x_1.). Moreover, if we know that there are no transfers of money within the cartel, this fact can be taken into account through a lump-sum transfer L_1 of t_1x_1 *from* the cartel to the cartel member, thereby making the net transfer from the cartel to the cartel member equal to zero.

Alternatively, if we observe that production is higher than x_0, say, x_2, this can be mimicked by a negative unit tax t_2, that is, *as if* this cartel member receives the subsidy t_2 from the cartel for each unit it produces (total received amount of money is t_2x_2). Again, if we know that there are no transfers of money within the cartel, this fact can be taken into account through a lump-sum transfer L_2 of t_2x_2 from the cartel member to the cartel, which will net out the subsidy transfer from the cartel.

In our numerical model we use this modeling strategy to mimic deviations from competitive behavior in production of electricity, that is, each group of producers is modeled *as if* they face a (positive or negative) unit tax on production and receives a (positive or negative) lump-sum transfer. Whereas the story in Fig. 1 was based on no capacity constraints, in the numerical model there are a number of capacity constraints, and thus in equilibrium marginal costs typically reflect several positive shadow values. Henceforth, the (unit) "taxes" are termed the electricity production deviation parameters; they reflect deviation from competitive behavior in electricity production and could have any number of sources. Technically, this deviation parameter is a linear term in the first-order condition for optimal electricity production, see Section 3. In Section 4 we explain how the electricity production deviation parameters are calibrated. In the numerical model, there is one deviation parameter for each group of electricity producers, where a group consists of all producers using the same type of technology in a model country. The calibrated

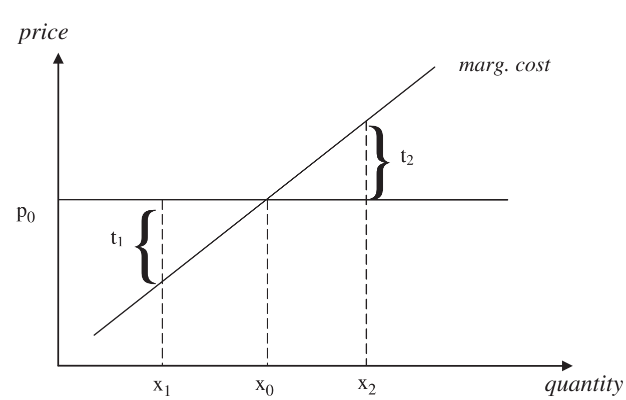

Fig. 1. The electricity production deviation parameters.

[4] For studies on measuring market power in the electricity industry, see Wolfram (1999) on the British spot market and Borenstein et al. (2002) on the California wholesale market.

value of the electricity production deviation parameter will differ across technologies and model countries.

Our modeling of electricity producers could be consistent with several types of deviation from competitive behavior, for example, monopolies, oligopolies or cartels. It could also be consistent with various forms of government intervention: for example, regulations restricting the use of market power, subsidizing coal industries, protecting domestic companies from foreign competition or policies encouraging the use of particular technologies such as green power. For our purposes, the causes of the deviation from the competitive case need not be identified, but the magnitudes of the deviation parameters must be estimated.

As explained above, we model deviations from the competitive outcome through a deviation parameter t. Note that a marginal increase in production from a producer receiving a subsidy t_2 leads to an increase in income by $p + t_2$, whereas under the theory of conjectural variation a marginal increase in production raises income by $p + \frac{dp}{d(\sum x_j)} \frac{d(\sum x_j)}{dx_i} x_i$, see above. Hence, these two approaches are closely related: If we know all equilibrium values t_2^* and x_j^*, the corresponding conjectural derivative can be calculated as

$$\frac{d\left(\sum x_j\right)}{dx_i} = \frac{t_2^*}{x_i^* \, dp / d\left(\sum x_j^*\right)} \tag{1}$$

if the inverse demand function $p(\sum x_i)$ were differentiable. In particular, in the competitive case $t_2 = 0$ and using Eq. (1) we obtain $\frac{d\left(\sum x_j\right)}{dx_i} = 0$, which is consistent with our discussion above about the conjectural derivative.

2.3. Market structure — domestic retail

Whereas in our numerical model the decisions of an electricity producer follow from the solution of a detailed optimization problem, there is no explicit optimization problem for retailers. This fact reflects that in the numerical model, a retailer buys energy and just transports/distributes it to the end-users at constant costs, but may be able to harvest a profit.

If there is perfect competition in electricity retail, then the difference between (i) the end-user price of electricity and (ii) the price obtained by the electricity producers (at the plants) equals the sum of taxes and the costs of domestic transport and distribution, including losses, that is, there is no profit margin. Correspondingly, under a competitive regime, the difference between (i) the end-user price of gas and (ii) the beach price of gas equals the sum of taxes and the costs of domestic transport and distribution, including losses.

We observe, however, that the end-user price less the price obtained by the electricity producers/the beach price of gas differs from the sum of taxes plus costs of domestic transport and distribution, including losses. The difference, henceforth termed the retail deviation parameter, is positive, and hence reflects profits in retailing. Our data suggests that the retail deviation parameter differs between energy goods, user groups and countries: that is, between different user groups of electricity (or gas) in the same country, and between the same user group of electricity (or gas) in different countries. This observation suggests there was price discrimination in energy retailing in our data year.

2.4. Market structure — international transmission

We now turn to international traders of electricity or gas. We may mimic the market structure in international transmission in the same way as we did for electricity production, that is, through (positive or negative) unit taxes combined with lump-sum transfers. However, it turns out that our suggested way to model liberalization of electricity production or energy retail implies unreasonably large trade effects in our numerical model The simplest way to avoid such trade effects is to impose trade restrictions, requiring all pairs of net exports of gas and electricity between the model countries to be unchanged if there is a partial liberalization in another sector. Below we follow this strategy.

2.4.1. Identification of partial liberalizations

We identify the effects of a partial liberalization in electricity production, that is, of introducing cost efficiency in electricity production, by removing the electricity production deviation parameters while retaining the retail deviation parameters and at the same time requiring all pairs of net exports of gas and electricity between the model countries to be unchanged. Similarly, we identify the effects of liberalizing domestic electricity (gas) retail by removing the electricity (gas) retail deviation parameters and at the same time requiring all pairs of net exports of gas and electricity between the model countries to be unchanged. Finally, the effects of a liberalization of trade between the model countries in electricity (gas) are identified by replacing the quantitative trade restrictions for electricity (gas) with perfectly working third-party access to international electricity (gas) transmission in Western Europe. The latter means that international transport tariffs are equal to marginal costs when capacity is not fully utilized, whereas tariffs restrict the demand for international transmission services to the available capacity when the capacity would otherwise be insufficient. The identification of effects of different types of partial liberalization is the key issue of the present paper, and the results are reported in Section 5.

3. The model

Our empirical model, LIBEMOD MP, is a generalization of the model LIBEMOD: see Aune et al. (2008a) for a documentation of LIBEMOD. The main difference between the two models is the market structure. LIBEMOD assumes that all markets are competitive, whereas in LIBEMOD MP most markets can be non-competitive: through suitable choices of parameter values, the competitive outcome (LIBEMOD) is a special case of LIBEMOD MP.

LIBEMOD MP specifies seven energy goods: coking coal, steam coal, lignite, natural gas, oil, biomass and electricity. With some exceptions, these are produced, traded and consumed in all model countries, which are the following 16 Western European countries: Austria, Belgium & Luxembourg, Denmark, Finland, France, Germany, Greece, Ireland, Italy, the Netherlands, Norway, Spain, Sweden, Switzerland, Portugal and the United Kingdom.

All countries in the world that are not model countries produce, trade and consume coking coal, steam coal and oil. These goods are traded in competitive world markets. For all other energy goods, markets are not competitive. Natural gas and electricity are traded between the model countries. In addition, some of the non-model countries also export (exogenously given quantities of) gas, LNG and electricity to the model countries (and vice versa). The remaining goods – lignite and biomass – are not traded internationally (domestic markets only), but the model determines how lignite is allocated between different domestic users and also determines the supply of biomass (which is used in domestic bio-power production).

In each model country, there is a node at a central point in the country. International trade in gas requires pipes running between the node in the export country and the node in the import country. Similarly, trade in electricity requires transmission lines running between the node in the export country and the node in the import country. For both gas and electricity, there are capacity constraints in international transmission. These capacities are given in the short run, but are determined in the long-run version of the model. In each model country, energy is transported and distributed from the country node to the end users at constant costs (with prices including a potential profit margin; see the discussion in Section 2) and without capacity constraints. These costs differ by user group and energy good.

There are four groups of users of energy in each model country. First, there is intermediate demand from electricity producers: for example, gas power producers demand natural gas. Furthermore, there is demand from end users: the household, industry and transport sectors, though the latter demands only oil products. For end users, demand is derived from a nested CES utility function with five levels. At the top-nest level, there are substitution possibilities between energy-related goods and other forms of consumption. At the second level, consumers face a trade-off between consumption based on the different energy sources. Each of these is a nest describing complementarity between the actual energy source and consumption goods that use this energy source (for example, 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 six time periods over the 24-hour cycle. Thus, except for electricity, energy goods are traded in annual markets. Note that the calibrated parameters of the utility functions differ between end users and countries in order to induce different demand elasticities.

In each model country, there is production of electricity by various technologies: steam coal power, lignite power, gas power, oil power, reservoir hydro power, pumped storage power, nuclear, waste power and wind power. Some of these are not available in all countries. In general, for each technology and each country, efficiency varies across power plants. There are costs related to electricity production: fuel costs, non-fuel operating costs, maintenance costs (related to maintained power capacity), start-up costs (related to additional capacity started in a time period) and investment costs. The power producer obtains revenues either from using the maintained power capacity to produce and sell electricity or by selling the remaining part of the maintained power capacity to a national system operator, who buys reserve power capacity in order to ensure (if necessary) that the national electricity system does not break down.

Power producers face some technical constraints. For example, maintained capacity should not exceed installed capacity. In addition, there are technology-specific constraints. For example, for reservoir hydro, the reservoir filling at the end of a season cannot exceed the reservoir capacity. Moreover, total use of water cannot exceed total availability of water (the sum of seasonal inflow of water and reservoir filling at the end of the previous season). Each power producer maximizes profits subject to the technical constraints. This optimization problem implies a number of first-order conditions, which determine the operating and investment decisions of the producer.

We now give a technical description of supply of electricity. We first consider the short-run case in which the capacity is given. (The investment decision of a power producer is discussed later.) In order to simplify matters, we consider only one technology (gas power) and we also consider production in only one country. Further, we disregard non-fuel operating costs.

The fact that efficiency varies across gas power plants is modeled in LIBEMOD *as if* there were one single gas power producer with a number of heterogeneous plants, each with a distinct efficiency. Let $x(y_t)$ be the input requirement function that specifies the amount of gas required to produce the amount y_t of electricity in period t.[5] $x'(y_t) > 0$ is then the marginal fuel use, and by assumption this is increasing in electricity production ($x''(y_t) > 0$), which reflects decreasing efficiency — less efficient plants are phased in as production increases. Then fuel costs in period t are given by $x(y_t)P^g$, where P^g is the (annual) user price of gas.

In addition to fuel input, the producer chooses the level of power capacity that is maintained (K^M), thus incurring a unit maintenance cost c^M per power unit. Further, if the producer chooses to produce more electricity in one period than in the previous period in the same season, he will incur start-up or ramping-up costs. These are c^S per unit of started power capacity (K_t^S) in each period. Thus, in the short run total costs are given by:

$$C = \sum_t x(y_t)P^g + c^M K^M + \sum_{t \in T} c^S K_t^S. \tag{2}$$

The income from gas power production consists 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. Income from sales of electricity 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 in period t. Thus, the income from gas power production is:

$$I = \sum_t \left(P_t y_t + P_t^R K_t^R\right). \tag{3}$$

The producer faces some constraints. Below, the restrictions on the optimization 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 the (predetermined) installed power capacity (K^0):

$$K^M \le K^0 \perp \lambda \ge 0, \tag{4}$$

where λ is the shadow price of installed power capacity.[6]

Second, in each period, production of electricity (y_t) is constrained by the maintained energy capacity, net of the capacity sold as reserve capacity to the system operator. This net energy capacity equals the net power capacity ($K^M - K_t^R$) multiplied by the number of hours in the period (ψ_t):

$$y_t \le \psi_t \left(K^M - K_t^R\right) \perp \mu_t \ge 0. \tag{5}$$

Third, all power plants need some downtime for technical maintenance. Therefore, total annual production cannot exceed a share (ξ) of the gross maintained energy capacity:

$$\sum_t y_t \le \xi \sum_t \psi_t K^M \perp \eta \ge 0. \tag{6}$$

Note that this is an annual constraint, so the producer may choose in which period(s) technical maintenance will take place.

Fourth, start-up and ramping-up costs are incurred if electricity production varies between periods in the same season. These costs depend on the additional capacity started at the beginning of each period; that is, on the difference between the capacity use in one period and the capacity use in the previous period during the same season. The start-up capacity (K_t^S) must therefore satisfy the following requirement:

$$y_t \Big/ \psi_t - y_{t-1} \Big/ \psi_{t-1} \le K_t^S \perp \phi_t \ge 0, \tag{7}$$

where y_t/ψ_t is the actual capacity used in period t and y_{t-1}/ψ_{t-1} is the actual capacity used in the previous period in the same season. Each

[5] Below we disregard – primarily because of lack of data – the possibility of improving energy efficiency in existing plants. Such investments may sometimes be more cost efficient than building additional electricity generation capacity.

[6] In general, the notation $a \le 0 \perp b \ge 0$ is shorthand for $a \le 0$ and $b \ge 0$ and $ab = 0$, where a is the derivative of the Lagrangian w.r.t. b.

produced quantity y_t is thus involved in two inequalities, once for period t and once for period $t + 1$.

Finally, we introduce the deviation parameter s, which is our way to model deviations from competitive behavior for electricity producers: as explained in Section 2, the producer acts *as if* he faces a tax s on production $\sum_t y_t$.

The producer maximizes profits: that is, income (Eq. (3)) less costs (Eq. (2)) and less the *as if* tax payment $s\sum_t y_t$, given the constraints (4)–(7) and chooses period production of electricity (or equivalently, period input of natural gas), sale of reserve capacity, maintained capacity and start-up capacity. The Lagrangian of the gas power producer is:

$$\begin{aligned} L = &\sum_t \left(P_t y_t + P_t^R K_t^R\right) - \sum_t x(y_t) P^g - c^M K^M - \sum_{t \in T} c^S K_t^S \\ &- \lambda\left\{K^M - K^0\right\} - \sum_t \mu_t \left\{y_t - c_t\left(K^M - K_t^R\right)\right\} - \eta\left\{\sum_t y_t - \xi \sum_t \psi_t K^M\right\} \\ &- \sum_t \phi_t \left\{ {y_t}/{\psi_t} - {y_{t-1}}/{\psi_{t-1}} - K_t^S\right\} - s\sum_t y_t. \end{aligned} \tag{8}$$

The first-order condition with respect to produced electricity is:

$$P_t \le x'(y_t) P^g + \mu_t + \eta + \frac{\phi_t - \phi_{t+1}}{\psi_t} + s \perp y_t \ge 0. \tag{9}$$

Hence, in each period an internal solution requires that the price of electricity (P_t) should equal the sum of i) marginal input costs of production ($x'(y_t)P^g$), ii) three suitably weighted shadow prices ($\mu_t + \eta + \frac{\phi_t - \phi_{t+1}}{\psi_t}$), and iii) the electricity production deviation parameter (s). The shadow price term contains the shadow price of periodic energy capacity (μ_t), the shadow price of annual energy capacity (η) and the difference (measured per hour) between the shadow price of capacity used in this and the following period $\left(\frac{\phi_t - \phi_{t+1}}{\psi_t}\right)$. Note that $\mu_t > 0$ reflects that increased production in period t is not possible for a *given* maintained capacity K^M net of reserve power capacity K_t^R, whereas $\phi_t > 0$ reflects that production in period t cannot be increased for a *given* start-up capacity K_t^S. Because the shadow values will in general differ over time, the difference between the price of electricity (P_t) and the observed marginal costs ($x'(y_t)P^g$) will also differ over time. This difference will typically be large during peak hours.

The first-order condition with respect to sale of reserve capacity is:

$$P_t^R \le \mu_t \psi_t \perp K_t^R \ge 0, \tag{10}$$

that is, the income from selling one more unit of power capacity to the system operator (P_t^R) should (in an internal solution) equal its opportunity cost, which is the value (μ_t) of increased production due to a higher net energy capacity being available for electricity production during all hours in the period (ψ_t).

Further, the first-order condition with respect to maintained capacity is:

$$\sum_t \psi_t (\mu_t + \eta\xi) \le c^M + \lambda \perp K^M \ge 0. \tag{11}$$

Hence, in an internal solution the cost of increasing maintained capacity marginally – the sum of the maintenance cost (c^M) and the shadow price of installed capacity (λ) – should be equal to the value of increased annual production following from this policy. The latter is the shadow value (μ_t) of the net energy capacity times the number of hours in the period (ψ_t), summed over all periods, i.e., the value of increased production where the marginal value is positive. In addition comes the value of increased potential for annual production if the downtime restriction is binding, reflected by the maximum annual operating time evaluated by the shadow value of the gross maintained energy capacity $\left(\eta\xi\sum_t \psi_t\right)$.[7]

Finally, the first-order condition with respect to the start-up capacity is:

$$\phi_t \le c^S \perp K_t^S \ge 0, \tag{12}$$

that is, in each period, the shadow price of start-up capacity ϕ_t, which reflects the benefit of increased start-up capacity through higher production, should (in an internal solution) be equal to the start-up cost c^s; alternatively, start-up capacity should be zero.

LIBEMOD MP is available in two versions. In the short-run version, all capacities in power production (and also all capacities for international transmission of gas/electricity, see discussion below) are given. In the long-run version, these capacities are endogenously determined through profit maximization at the micro level. In the model, investment can take place only in new power plants. In contrast, the installed capacity for plants being available for production in the data year of the model ("old plants"), cannot be expanded. We now turn to the investment decision of power producers.

A (potentially) new plant has the same type of short-run revenues and costs as an old plant, although it has a higher thermal efficiency. The new plant also faces the same technical restrictions (4)–(7) as an old plant. Hence, the first-order conditions (9)–(12) are also valid for a new plant. On the other hand, the new plant has investment costs $c^{inv}K^{inv}$ where c^{inv} is annualized capital costs per unit of investment and K^{inv} is investment. Using the fact that for new technologies, total capacity will be equal to investment $K^0 = K^{inv}$, and maximizing profit with respect to K^{inv}, the investment criteria can be written as:

$$\lambda \le c^{inv} \perp K^{inv} \ge 0. \tag{13}$$

This implies that if investment is positive, the annualized investment cost (c^{inv}) must equal the shadow price of installed capacity (λ), i.e., the increase in operating surplus resulting from one extra unit of capacity.

Once electricity is produced, it can be sold either to domestic users or exported. In the first case, electricity is transported and distributed domestically. Let q be the set of users of electricity, that is, household, industry and intermediate users in the electricity sector (pump storage power producers). In line with the explanation in Section 2, the relationship between the end-user price of electricity of user group q in time period t (P_{tq}^x), the price of electricity obtained by the producer (at the plant) in time period t (P_t) and the electricity retail deviation parameter of user group q in time period t ($æ_{tq}$) is:

$$P_{tq}^x = \left[\frac{1}{\theta_q}\left(P_t + æ_{tq}\right) + d_q\right]\left(1 + \tau_q\right), \tag{14}$$

where θ_q is the share of electricity that is not lost during domestic transport and distribution, d_q is the sum of costs of domestic transportation, distribution and energy/environmental taxes, and τ_q is the VAT tax rate. In the model, there is such a relationship for electricity retail in each model country. Further, there is a similar relationship for gas retail, but because the model has annual markets for gas, that relationship is expressed in annual prices.

We now turn to export of electricity. As explained in Section 2, before international transmission is liberalized all export quantities are fixed in the model. On the other hand, exports change after a liberalization of international transmission. We now explain how international transmission is modeled after a liberalization.

[7] If $\lambda > 0$, then increasing the maintained capacity marginally requires that also the installed capacity is raised.

In the short run, the capacity of international transmission from a country m to a country n is given (K^0_{mn}). Suppose first that the transmission line between m and n is owned by an agent. (Below we give an alternative interpretation of the model.) In each time period t the owner can (after a liberalization of international transmission) either buy electricity in country m and export it to country n (z_{mnt}), or buy electricity in country n and export it to country m (z_{nmt}). Taking into account the share of the transported electricity that is not lost (θ_{mn}) and also the operating costs of international transmission (c_{mn}), the annual profit of the owner of the line between m and n is:

$$\Pi_{mn} = \sum_t \left\{ \left[P_{nt} - \frac{P_{mt}}{\theta_{mn}} - c_{mn}\right] z_{mnt} + \left[P_{mt} - \frac{P_{nt}}{\theta_{nm}} - c_{nm}\right] z_{nmt} \right\}. \qquad (15)$$

Here $\frac{P_{mt}}{\theta_{mn}}$ is the loss-adjusted unit price in the exporting country that the owner can sell for P_{nt} in the importing country. Typically, $\theta_{mn} = \theta_{nm}$ and $c_{mn} = c_{nm}$.

The owner has to take into account that in each time period, the flow of electricity is constrained by the predetermined transmission line capacity:

$$z_{mnt} - z_{nmt} \le \psi_t K^0_{mn} \perp \mu_{mnt} \ge 0, \qquad (16)$$

where, as above, ψ_t is the number of hours in time period t. Note that trade can take place only in one direction in each time period, that is, in each time period either z_{mnt} or z_{nmt} (or both) is zero.

Under the assumption of a perfectly competitive equilibrium, the (natural monopolist) transmission line owner must be regulated to act as a price taker in both countries (m and n) and will then maximize (15) subject to (16) with respect to the quantity traded in each direction in each time period. The first-order condition for export from country m can be expressed as:

$$P_{nt} - \frac{P_{mt}}{\theta_{mn}} - c_{mn} - \mu_{mnt} + \mu_{nmt} \le 0 \perp z^E_{mnt} \ge 0, \qquad (17)$$

where there is a similar relationship for export from country n. If it is optimal to export from country m in period t, then $\mu_{nmt} = 0$ and the loss-adjusted price difference between the importing and exporting country $\left(P_{nt} - \frac{P_{mt}}{\theta_{mn}}\right)$ should equal total marginal costs, that is, the sum of the monetary cost of transporting electricity (c_{mn}) and the shadow value of increased capacity (μ_{mnt}).

While trade has been formulated as if the transmission line owner buys electricity in one market and sells it in another, the following alternative interpretation is also possible: a regulated or publicly owned transmission company is instructed to set tariffs to cover marginal costs (c_{mn}) alongside a capacity charge equal to μ_{mnt}. The capacity charge is only allowed to be positive when capacity is fully utilized and is then set sufficiently high to ensure that the demand for transportation is no larger than the capacity. Under this interpretation, there is perfect third-party access (TPA) and so any agent may engage in trade, attempting to exploit the price differential $P_{nt} - \frac{P_{mt}}{\theta_{mn}}$ but facing a tariff equivalent to $c_{mn} + \mu_{mnt}$. In equilibrium, all such trading agents earn zero (pure) profits.

In the long run, the owner of the transmission line between m and n can expand the capacity. Let c^{inv}_{mn} be the annualized (unit) capital cost for the expansion of the international electricity transmission line, and let K^{inv}_{mn} be the expansion. Profits is then given by (15) less $c^{inv}_{mn}K^{inv}_{mn}$, whereas K^0_{mn} in (16) is replaced with $K^0_{mn} + K^{inv}_{mn}$. The first-order condition for investment in electricity transmission is given by:

$$\sum_t \psi_t \left(\mu^E_{mnt} + \mu^E_{nmt}\right) \le c^{inv}_{mn} \perp K^{inv}_{mn} \ge 0. \qquad (18)$$

Eq. (18) takes into account the fact that investment increases capacity in both directions, and that the increased capacity can be utilized in all periods.

Above we have explained the operating and investment decision of an owner of an international electricity transmission line. An owner of an international gas pipe line has the same type of first-order conditions, the difference being that gas is traded in one period only.

Note that once international transmission of natural gas and/or electricity is liberalized, domestic mismatches will be transferred to the international market: a country facing severe supply problems will increase its imports of electricity from other model countries.

LIBEMOD MP determines all energy quantities – production, trade, consumption and (in the long-run version of the model) also investment – and all energy prices, both producer prices and end-user prices, as well as emission of CO_2 by sector and country. If some or all of the deviation parameters are changed, a new equilibrium is computed, and the difference in outcome is due to the shift in the deviation parameters. Because deviation parameters are zero in a competitive equilibrium, the effect of liberalizing electricity production is identified by comparing (i) the model solution with all deviation parameters in place with (ii) a new equilibrium where all electricity production deviation parameters s in the first-order condition for electricity production, see Eq. (9), are eliminated, while retaining the retail deviation parameters and at the same time requiring all pairs of net exports of gas and electricity between the model countries to be unchanged. The effect of liberalizing domestic electricity (or gas) retailing is similarly identified by setting the retail deviation parameters $æ_{tq}$ in the end-user price Eq. (14) at zero, and at the same time requiring all pairs of net exports of gas and electricity between the model countries to be unchanged. Finally, the effect of liberalizing international transmission of electricity (gas) is identified by replacing exogenous traded electricity (gas) quantities with competitive behavior in international electricity (gas) transmission.

4. Data and calibration

Data for quantities and prices build on statistics published by international organizations such as OECD/IEA, UNIPEDE, UCPTE and NORDEL, supplemented with national sources when necessary, see Appendix B in Aune et al. (2008a) for a detailed documentation. The data year of the model is 2000. Parameter values are typically taken from published papers, or from industry sources/conversation with sector experts. In addition, some parameters are estimated, and several are calibrated, see the discussion below on calibration.

In LIBEMOD MP, demand elasticities follow from the parameters of the calibrated multi-level CES utility functions, and will in general vary between equilibria. The short-run demand elasticities for the model countries lie in the interval (−0.15; −0.43) in the calibration equilibrium, which is based on observed 2000 prices and quantities, whereas the weighted short-run elasticity (aggregated over fuels, sectors and countries) is −0.23. The long-term demand elasticities for the model countries (used in the long-run version of the model with a time perspective of about 10 years) lie in the interval (−0.27; −1.03), see Table 1 for more detailed information on demand elasticities.

Supply of fossil fuels also differs between energy goods and between short and long run. For oil, the short-run (long-run) elasticity is 0.25 (1.00) for all countries. Coal supply is modeled separately for

Table 1
Own-price demand elasticities in the calibration (observed) equilibrium. Weighted average over model countries.

	Short run			Long run		
	Households	Industry	Transport	Households	Industry	Transport
Electricity	−0.26	−0.18	N.A.	−0.45	−0.63	N.A.
Gas	−0.31	−0.28	N.A.	−0.54	−0.76	N.A.
Coal	−0.22	−0.30	N.A.	−0.61	−0.69	N.A.
Oil	−0.26	−0.22	−0.24	−0.55	−0.61	−0.45

each of the three coal types (steam coal, coking coal and lignite). Below we focus on steam coal and coking coal. The short-run coal supply functions of the major coal exporting countries (Australia, Canada, China, Colombia and Venezuela, Indonesia, Poland and South Africa) are fitted to detailed export supply information from industry sources. The remaining countries have a linear supply function with a calibrated short-run short-run elasticity of 1.0 for exogenous countries and 0.75 for model countries (in the observation points). In the long-run model, all countries have a linear supply function with an elasticity of 4.0 in the observation point.

In the short-run model, the supply of natural gas from each of the model countries is exogenous (equal to the 2000 extraction levels), reflecting the present structure in the Western European natural gas markets with, for example, take-or-pay contracts. In the long-run model, large suppliers of natural gas – the Netherlands, Norway and the United Kingdom – have convex supply functions, while all other model countries have linear marginal cost functions with long-run elasticities equal to 1. The long-run supply functions for the Netherlands, Norway and the United Kingdom are constructed based on detailed field information, assuming, in line with the official views of these countries, cost efficient extraction, that is, cet. par., cheap fields are extracted before more expensive fields. Note that our field information suggests cost efficiency also in the short run.

For natural gas, we assume that total cost of constructing a new international transmission pipe is 1.25 USD per toe per 100 km in model countries (0.5 in exogenous countries), and twice as high for off-shore pipes. For domestic transport and distribution of gas, our starting point is IEA (1998) where the costs of transport in Germany are 55 USD per toe, whereas the costs of distribution in Germany are 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 because of the amount of natural gas transported/distributed and the length of the domestic transport/distribution network.[8] This methodology implies, however, a few extreme results, which we treat by imposing cost ceilings. For households, the sum of domestic costs of transport and distribution lies between 116 and 268 USD per toe, whereas the corresponding interval for the industry sector is 19 to 74 USD per toe.

For high-voltage electricity transmission lines, we have assumed that total construction cost is 200 USD per MW*kilometer, whereas the corresponding cost for sea cables is 1300 USD per MW*kilometer. For industry, cost of domestic electricity transport is set to 2.7 USD per MWh in all model countries, whereas the household cost of transport and distribution varies across countries in proportion to estimated distribution losses with an average value of 17 USD per MWh.

We now turn to the remaining calibrated model parameters. These are the electricity production deviation parameters, the electricity retail and gas retail deviation parameters (see Section 2), and also the thermal efficiency parameters for plants that were available for operation in 2000 ("old plants"). In addition, we have calibrated a country-specific 'system price' of electricity, which is needed in order to identify the different partial liberalizations. The system price is the price an electricity producer obtains at the plant (country node) when selling electricity to either domestic retailers or international traders. In a perfect competitive equilibrium, this would equal the marginal costs of the most expensive technology (including any capacity shadow values). Because we do not have data on the system price for the observed 2000 non-competitive outcome, it has to be calibrated. The way the system price is calibrated has consequences for the calculated deviation parameters, and therefore for the separate effects of each partial liberalization. It does not, however, have consequences for the fully liberalized outcome.

[8] According to our methodology, unit cost of transport/distribution is lower, cet. par., the greater amount of energy that is transported, and the shorter is the transport distance.

The electricity production deviation parameters, the thermal efficiency parameters and the country-specific electricity system price are calibrated using the electricity production submodel of the Libemod MP model. These parameters are determined from minimizing short-run cost of production for each model country, see Eq. (2), aggregated over all technologies, taking into account all technical constraints facing all technologies in a model country, see Eqs. (4)–(7) for the case of gas power, and minimizing with respect to the short-run decision variables of the electricity producers.

In the cost-minimization problem, we also take the following factors into account. First, we do not have data on production of electricity for each technology in each time period, but rather country-specific observations of total production (aggregated over all technologies) in each time period and also total annual production of each technology (in each model country). These restrictions enter as constraints in the cost-minimization problem. For example, for gas power the latter restriction is specified as $y^0 = \sum_t y_t^0$ where y^0 is observed annual production of gas power in the data year and y_t^0 is the non-observed production of gas power in period t in the data year (to be calibrated). Note that y_t^0 is determined as part of the solution of the cost-minimization problem. Second, for each model country and for each type of technology, we specify a uniform distribution function of the inverse thermal efficiencies of power plants and also use technology-specific information about the most efficient plant in the data year. Finally, in many countries there are technologies with very small market shares: for example, nuclear power in Norway, where capacity is installed purely for research purposes. Similarly, in the data year 2000 there were small-scale experiments with environmental technologies in many countries. These technologies are treated as exogenous in the calibration of the model. This is done to avoid the system price being determined by, for example, small-scale experiments.

From the solution of the cost-minimization problem we obtain, for each model country, the electricity production deviation parameters, the thermal efficiency parameters and the system price, see Aune et al. (2008b). The system price is defined as the marginal cost – including shadow values but not including the electricity production deviation parameter – of the most expensive technology entering the cost-minimization problem. The calibrated system price for the year 2000 varies from 17 USD/MWh in Norway to 76 USD/MWh in Greece (due to a large oil power share). Most major Western European countries have a calibrated system price between 30 and 50 USD/MWh. The calibrated electricity production deviation parameters are ranging from zero to a 20 USD/MWh, with a weighted average of 8.8 USD/MWh.

Once we have found the calibrated system price of electricity, it is easy to identify the electricity retail deviation parameters — one for each user group in each time period in each model country. These follow directly from Eq. (14) as all factors in this relation, except the electricity retail deviation parameter, are now known. The electricity retail deviation parameters average 37 and 3 USD/MWh for households and industry respectively, which compares with average end-user prices at 109 and 39 USD/MWh. The deviation parameters for gas retail are found in a similar way, and are on average 62, 21 and 26 USD/toe for households, industry and gas power respectively, whereas average end-user prices were 421, 181 and 160 USD/toe in the year 2000.

5. Results

In this section we report the results of partial liberalizations in the energy industry in Western Europe. For both gas and electricity we consider the effects of liberalization of *domestic markets* and *international trade* between countries in Western Europe separately. For domestic electricity markets, we also consider the effects of liberalizing production and retail separately. In contrast, for gas extraction we have – in line with our detailed gas field data – assumed cost

Table 2
Partial liberalization of energy markets: electricity is liberalized first; effects on welfare of each step (1000 million USD).

		Consumer surplus in model countries	Producer surplus in model countries	International trader surplus	Sum model countries[a]	Sum all countries[b]
Short run	Partial liberalization in:					
	Electricity production	11.1	−6.4	−0.9	3.9	0.8
	Domestic electricity retail	42.6	−35.3	1.8	4.7	9.9
	International electricity trade	4.4	−2.3	−1.3	0.6	0.7
	Domestic gas retail	3.5	−1.8	−1.3	−1.0	0.4
	International gas trade	−2.4	−0.7	−3.3	−2.7	0.3
	Total effect	59.2	−46.5	−5.1	5.5	12.0
Long run	Partial liberalization in:					
	Electricity production[c]					
	Domestic electricity retail	73.0	−51.7	−1.4	17.0	17.9
	International electricity trade	−3.5	3.6	0.3	0.1	0.1
	Domestic gas retail	10.7	−9.7	1.2	1.2	1.9
	International gas trade	0.2	1.4	−9.6	−2.2	0.2
	Total effect	80.4	−56.4	−9.5	16.2	20.2

[a] Sum of consumer surplus, producer surplus and tax revenues to the government in the model countries, plus half the international trader surplus on each international transmission connection.
[b] Sum of consumer surplus, producer surplus, tax revenues to the government and international trader surplus in all countries.
[c] In the long-run version of the model, it is only possible to identify the combined effect of the liberalization of electricity production and the liberalization of domestic electricity retail.

efficiency, whereas for gas retail data suggest there are potential efficiency gains from liberalization. Hence, liberalization of domestic gas markets means that (only) gas retail is liberalized. The order of liberalization is as given in Table 2, where electricity is liberalized first, but we will return to check the soundness of this assumption.

In all cases we consider the effects of liberalization both in the *short run* (pre-existing capacities) and in the *long run* (endogenous determination of capacities for power production, international transport of gas and international transport of electricity between model countries). The long-run scenarios assume the same income levels as in the calibration year 2000 and are therefore not predictions of the future, but they may be regarded as a comparative static analysis of how the different agents would have adapted had the liberalization been announced quite a few years before 2000.

In order to avoid results that are too detailed, we focus on the group of all model countries (not each model country) and the group of non-model countries. For each group of countries, there are four types of agents: consumers of energy, producers of energy, the government (receives taxes) and international traders in energy. For international traders, we do not know their country of origin, which within our model means that we do not fully know how the ownership of each international electricity transmission line and each international gas pipeline is distributed between countries. In what follows we have assumed that 50% of each international electricity line and 50% of each international transmission pipe is owned by the importing (or exporting) country. The main welfare results of the present paper are robust relative to this assumption.

5.1. The main welfare effects: domestic electricity markets

As can be seen from Table 2, in the short run a full liberalization increases annual consumer surplus in the model countries by \$59 billion (\$59,200 million), reduces annual producer surplus in the model countries by \$47 billion, increases annual welfare in the model countries by \$6 billion and increases annual global welfare by \$12 billion.[9] In the long run, these effects are enhanced, with an increase of annual consumer surplus in the model countries of \$80 billion, a reduction of annual producer surplus in the model countries of \$56 billion, an increase in annual welfare in the model countries of \$16 billion and an increase of annual global welfare of \$20 billion. Roughly 90% of these effects are due to the liberalization of domestic electricity markets in the model countries: that is, the combined effect of liberalizing electricity production and domestic electricity retail. We will therefore focus mainly on the effects of the liberalization of domestic electricity markets.

In order to see what is driving the large changes of the liberalization of domestic electricity markets, consider the price and quantity responses reported in Table 3. There is a significant increase in production of electricity, particularly in the long run (18%), and a corresponding reduction in the long-run average end-user electricity price of 31%. In both the short and long run, the increase in production of electricity is mainly due to increased production in steam coal-fired plants. The effects on electricity supply of other types of liberalization are small.

In each model country, total supply of electricity was not efficient and also the composition of electricity technologies was not efficient in the data year 2000, see the discussion in the latter part of Section 4. As explained above, deviations from ideal (competitive) conditions in domestic electricity markets are taken into account through a set of deviation parameters in electricity production and a set of deviation parameters in electricity retailing. When examining the liberalization of domestic electricity markets, technically we eliminate these deviation parameters. Electricity technologies with initially high positive deviation parameters will then gain, and thus output from these technologies will increase. Steam coal power had high deviation parameters, and thus production from this technology will increase. The rise in production depends on the price of steam coal, other cost elements for steam coal plants, the distribution of fuel efficiency for steam coal plants and the price of electricity. Relative to other fuels, steam coal is cheap, but this effect is to some extent modified by rather low efficiency in steam coal power plants. Overall, marginal costs of production are quite low for steam coal power after the partial liberalization of domestic electricity markets, and hence the model predicts a large increase in steam coal power production.

Note that due to increased steam coal power production, the user-price of steam coal (average over all model countries and all user groups) increases by 25% in the short run. The significant short-run price effect reflects low supply elasticities of steam coal, whereas in the long run the price increase is moderate (3%) due to high supply elasticities. This is one reason why the short-run increase in steam coal power (39%) is lower than the long-run response (84%). In addition, in the long run there is profitable investment in steam coal power plants.

[9] The total liberalization results reported here are slightly different from those in Aune et al. (2008a) due to a different basis of comparison. The model solutions in the 2008 study are compared with a calibrated data set that retains some statistical errors. In this paper, we compare instead the model solution with a calibrated data set after the statistical errors are removed.

Table 3
Partial liberalization of energy markets: electricity is liberalized first; changes in electricity supply, gas consumption and average end-user prices for electricity and gas (percentage).

	Electricity supply		Electricity price		Gas consumption		Gas price	
	Short run	Long run	Short run	Long run	Short run	Long run	Short run	Long run
Partial liberalization in:								
Electricity production[a]	2.6		−4.3		0.0		0.4	
Domestic electricity retail	6.9	17.9	−21.6	−31.2	0.0	3.2	8.0	1.6
International electricity trade	0.2	−1.2	−1.2	1.6	0.0	0.2	−2.3	0.3
Domestic gas retail	−0.1	0.6	0.1	−1.2	0.0	5.0	−3.6	−9.1
International gas trade	−0.1	0.4	0.2	−0.4	−0.7	1.9	2.1	0.9
Total effect	9.4	17.7	−26.8	−31.2	−0.7	10.3	4.6	−6.3

[a] In the long-run version of the model, it is only possible to identify the combined effect of the liberalization of electricity production and the liberalization of domestic electricity retail.

Production from gas-fired power plants also increases due to the liberalization of domestic electricity markets, but measured in quantity (TWh) it is only about a quarter of the increase in steam coal power. On the other hand, there is a reduction in oil-based thermal power production, which after liberalization suffers from high costs.

Increased electricity production explains a substantial part of the welfare gain. There is, however, also an effect of equalizing net electricity prices (end-user prices less transport losses, costs of domestic transport, costs of distribution and taxes) across end users in a model country, which is part of the effect of liberalizing domestic electricity markets. Table 4 shows that in the short run, almost the entire reduction in electricity prices due to the liberalization of electricity retail is enjoyed by households (29.4%), whereas the reduction in prices to industry is marginal. In the long run, it is not possible to separate the effects of production efficiency and distribution efficiency of electricity (due to the way the long-run model is calibrated), but the combined effect is a reduction in prices for both user groups, though the reduction is much larger for households than for industry (36.9% vs. 16.3%). The model simulations thus indicate significant price discrimination between end users of electricity in 2000, with corresponding welfare gains when the price discrimination is removed.

5.2. Natural gas

We have already identified that one effect of liberalizing domestic electricity markets is increased gas power production. Demand for gas from gas-fired power plants therefore increases. Because total extraction of gas is given in the short run (per assumption), the end-user price of gas – average over all model countries and all user groups – increases in the short run (by 8%: see Table 3) due to the liberalization of domestic electricity markets. As seen from Table 4, the short-run percentage increase for households (5%) is lower than that for the other user groups of gas (12 and 18%), reflecting primarily that households, which have high costs of distribution, face by far the highest end-user price prior to liberalization.

In the long-run version of the model, we assume that the level of natural gas extraction is determined by competitive supply functions, see discussion in Section 4. As is well known, a change in market structure from non-competitive behavior (observed in 2000) to competitive supply tends to increase supply. Therefore, in the long run increased demand for gas due to the liberalization of domestic electricity markets is counteracted by increased supply of gas. The net effect of the liberalization of domestic electricity markets is a modest increase in the long-run average user prices for gas for all groups (1–3%: see Table 4).

We now turn to liberalization of gas markets. In both the short and long run, the liberalization of international gas transmission has marginal impact on the average gas price. On the other hand, the liberalization of domestic gas retail has impact on the price of gas. In 2000 there was price discrimination in the domestic gas market because net prices (end-user prices less cost of domestic transport, cost of distribution, domestic losses and taxes) differed across user groups. When eliminating the deviation parameters in domestic gas retail, households benefit significantly – in all model countries gas is moved from the industry sector and also from gas power production to the household sector, thereby equalizing net prices. The short-run end-user price of gas decreases by 9% for households because of liberalization of gas retail (see Table 4), whereas the prices for industry and gas power increase by 5%. These numbers can be compared to the deviation parameters for gas retail in Section 4; 15%, 12% and 16% for households, industry and gas power, respectively. Further, the short-run average price of gas decreases by 4% (see Table 3), whereas the long-run price of gas decreases by 9% due to liberalization in gas retail. The difference between the short-run and the long-run effect mainly reflects increased extraction of gas in the long run (see discussion above).

5.3. Price variations

Liberalizing domestic retail removes price discrimination and should equalize producer prices, that is, end-user prices less domestic

Table 4
Partial liberalization of energy markets: change in average end-user prices for electricity and gas by groups (percentage).

	Electricity				Nature gas					
	Households		Industry		Households		Industry		Gas power	
	Short run	Long run	Short run	Long run	Short run	Long run	Short run	Long run	Short run	Long run
Partial liberalization in:										
Electricity production[a]	−3.2		−7.4		−1.0		2.3		3.7	
Domestic electricity retail	−29.4	−36.9	−0.6	−16.3	6.0	1.1	9.7	2.5	13.9	2.4
International electricity trade	−1.0	1.5	−1.9	1.9	−1.3	0.1	−3.7	0.8	−4.0	0.3
Domestic gas retail	0.2	−0.9	0.2	−1.8	−8.5	−12.3	4.8	−2.4	5.0	−4.1
International gas trade	0.1	−0.4	0.3	−0.6	2.3	1.3	3.7	0.2	−1.1	0.2
Total effect	−33.3	−36.7	−9.4	−16.8	−2.5	−9.8	16.8	1.1	17.5	−1.2

[a] In the long-run version of the model, it is only possible to identify the combined effect of the liberalization of electricity production and the liberalization of domestic electricity retail.

losses, cost of domestic transport, cost of distribution and taxes, across different users in the same country. The dispersal of producer prices can be measured by the coefficient of variation: that is, the standard deviation relative to the average.

As seen from Table 5, the short-run effect of liberalizing domestic gas retail (after there has been a full liberalization of electricity) is a drop in the coefficient of variation for the national gas producer prices from 0.37 to 0.27. Because the coefficient of variation is zero within each country after domestic retail has been liberalized, the estimate of 0.27 reflects remaining differences in gas producer prices between countries.

When liberalizing international trade in Western Europe, energy is moved from high-price countries to low-price countries in order to obtain arbitrage profits. However, due to costs of international transmission, as well as capacity constraints in international transmission, producer prices are not completely equalized across countries. As seen from Table 5, the liberalization of international gas transmission lowers the short-run coefficient of variation for national producer prices of gas from 0.27 to 0.09. Thus, in the short run most of the price differences between national producer prices of gas are eliminated after a full liberalization. Moreover, in the long run, when transmission capacity can be expanded, almost all price differences between countries are eliminated as a full liberalization lowers the coefficient of variation for national producer prices of gas to 0.03.

For electricity, the short-run coefficient of variation for the national producer prices drops from 0.45 to 0.35 due to the liberalization of domestic electricity retail, and further to 0.24 after a complete liberalization. The relatively high short-run coefficient of variation after a complete liberalization (0.24) mainly reflects binding capacity constraints in international electricity transmission. In the long run, the strictly positive coefficient of variation (0.11) reflects the fact that it is not profitable to expand electricity transmission lines to the extent that all differences in net prices between countries are eliminated.

Because liberalization of international transmission lowers the coefficient of variation for national producer prices, one might guess that the coefficient of variation for national end-user prices would also drop. This is the case for electricity, but not for natural gas. Our calculations reveal that the partial effect of liberalizing international transmission of gas is an increase in the short-run coefficient of variation for national end-user prices of gas (from 0.25 to 0.31). In fact, the total effect of a full liberalization is an increase in the short-run coefficient of variation for national end-user prices of gas from 0.26 (in 2000) to 0.33. The increase reflects the fact that in 2000 there was a tendency for negative correlation on the country level between end-user prices of gas and producer prices of gas. Hence countries with high end-user prices for gas had low producer prices and vice versa. When the difference in producer prices between countries is reduced (because of liberalization), roughly countries with high initial producer prices experience lower producer prices, and also end-user prices in these countries, which initially are low, are reduced. Further, countries with low initial producer prices experience higher producer prices, and also end-user prices in these countries, which initially are high, are increased. Hence, the low initial end-user prices are reduced, whereas the high initial end-user prices are increased, thereby increasing the coefficient of variation for end-user prices of gas.

Table 5
Partial liberalization of energy markets: coefficient of variation across countries for national producer prices for electricity and gas.

	Electricity		Natural gas	
	Short run	Long run	Short run	Long run
Partial liberalization in:				
Calibration (estimated producer prices)	0.45	0.44	0.28	0.17
Electricity production[a]	0.46		0.58	
Domestic electricity retail	0.35	0.22	0.40	0.25
International electricity trade	0.27	0.12	0.37	0.24
Domestic gas retail	0.27	0.13	0.27	0.17
International gas trade	0.24	0.11	0.09	0.03

[a] In the long-run version of the model, it is only possible to identify the combined effect of the liberalization of electricity production and the liberalization of domestic electricity retail.

5.4. Redistribution: gas vs. electricity

Liberalization causes important redistributions of economic surplus and has also impact on global economic welfare. As can be seen from Table 2, the welfare effects of liberalizations differ between electricity and gas. First, there are significant global economic welfare gains, and also redistribution effects (transfer from producer surplus to consumer surplus), from liberalizing *domestic electricity* markets. The economic welfare and redistribution effects of liberalizing *domestic gas* markets are much smaller, though qualitatively similar. These differences mainly reflect that the total amount of electricity increases much more than the total amount of gas, which mirrors the fact that gas is a scarce natural resource in limited supply, whereas electricity is a produced commodity with suboptimal supply in 2000 due to market imperfections. The differences in quantity response imply that the average price of electricity drops much more than the average price of gas.

Second, there is a considerable redistribution from *international gas* traders to gas producers when international gas transmission is liberalized, as this type of liberalization allows the gas producers to sell directly to the end users in the model countries. Under this partial liberalization, the difference between national producer prices of gas is almost eliminated because all arbitrage profits in international gas transmission are exhausted: see the discussion above. Hence international traders in gas suffer significant losses. For example, Norway as a gas producer benefits from liberalization of international gas transmission, whereas Norway as an owner of international transmission pipes loses. Note that presently much of the gas is sold on long-term contracts, yet such contracts are not incorporated into our model. LIBEMOD MP may thus overestimate this redistribution, especially in the short run, when contracts are still valid and end-user prices of gas increase because of increased demand. In addition, the gas importing countries may counteract the transfer of rent to the gas producers by taxing the use or imports of gas (if there are no legal constraints to such measures in international agreements). This policy alternative is not analyzed within the model.

Whereas there are significant redistribution effects when liberalizing international gas transmission, there are only small redistribution effects when liberalizing *international electricity transmission*. What explains this difference between gas and electricity?

Trade flows between model countries, measured, for example, as a share of total consumption, were, prior to liberalization, significantly lower for electricity than for gas, reflecting the fact that electricity is a good being produced in all countries, whereas a large fraction of total extraction of gas takes place in a limited number of countries. Hence, prior to the liberalization the gross value of international gas trade is much higher than the gross value of international electricity trade.

Further, while the liberalization of international gas transmission eliminates almost all differences in the national producer prices of gas and thus removes the source of making profits in international gas transmission, there are significant differences in national producer prices for electricity even after a complete liberalization: see the discussion above. The combination of these two factors explains why there are much larger redistribution effects for natural gas than for electricity when trade in Western Europe is liberalized.

5.5. Robustness

Above we have examined the case when electricity is liberalized before gas. The effects of a partial liberalization may, however, depend on the order in which different markets are liberalized. To analyze the impact of the order of liberalization, we compare the case in which *gas* is liberalized before electricity to the (initial) case in which *electricity* is liberalized before gas. In both instances, domestic markets are liberalized before international transmission. The welfare effects of the different stages of liberalization are shown in Table 6, where the effects are reported in the same order as in Table 2 (electricity is liberalized first) to make the comparison easier.

As can be seen from Table 6, the order of liberalization has in general little impact. For short-run effects, the largest difference is found in the distribution between consumer and producer surpluses in the model countries when electricity production is liberalized. For this type of partial liberalization, the effects on consumer surplus and producer surplus are largest when electricity markets are liberalized first. Note also that liberalizing domestic gas markets has a greater short-run redistributive effect from producer surplus to consumer surplus when gas is liberalized first. More generally, in the short run there is a slight 'diminishing returns' effect with respect to domestic market liberalizations: that is, the partial effect of liberalizing gas is highest if gas is liberalized before electricity, and the partial effect of liberalizing electricity is highest if electricity is liberalized before gas. This is roughly the case for price and quantity responses, as well as for redistribution between consumers and producers.

For the long-run effects of liberalizing domestic markets on consumer and producer surpluses, as well as the impact on global economic welfare, there is no clear 'diminishing returns' effect. In fact, for consumer surplus the effect of liberalizing domestic gas markets is actually slightly larger when gas is liberalized *after* electricity.

6. Concluding remarks

Earlier studies have considered the effects of a complete liberalization in Western Europe of either gas markets (Golombek et al., 1995), or electricity markets (Amundsen and Tjøtta, 1997), or both the gas and the electricity markets (Aune et al., 2004, 2008a). By contrast, in the present paper we focus on the effects of *partial* liberalizations, posing the questions: in which markets does liberalization yield large benefits, and where are the benefits smaller?

We find that a liberalization of electricity has stronger quantity and welfare effects than a liberalization of gas. Does this mainly reflect the fact that the electricity market is approximately three times as large as the gas market? The answer is no: the welfare effects of electricity liberalization are roughly ten times as large as those of gas liberalization. But maybe our result reflects that extraction of natural gas has been assumed to be cost efficient, which is not the case for supply of electricity? Again the answer is no: Table 2 shows that roughly 80% of the total welfare gain can be attributed to liberalization of electricity retail. Moreover, the gains from liberalization of electricity retail are about 25 times larger than the gains from gas retail liberalization. Thus, the greater quantity and welfare effects of liberalizing electricity markets reflect differences in market structure and resource rent between electricity and natural gas.

We also find that the liberalization of domestic energy markets has (overall) stronger effects than a liberalization of trade in energy between Western European countries. In particular, the liberalization of domestic electricity markets increases production of electricity significantly, leads to significant redistribution from producers to consumers, and increases global welfare. The liberalization of trade in energy in Western Europe has a small impact on prices and quantities, yet the liberalization of international gas transmission redistributes huge amounts of money from the transmission companies to the gas resource owners. A full liberalization increases (long-run) economic welfare in Western Europe by around \$16 billion per year, which corresponds to about 7% of gross value added in the energy industry in Western Europe.

All the different types of partial liberalization increase global welfare, both in the short run and the long run. There is one exception, namely, the liberalization of international gas transmission in the short run. Due to pre-existing taxes, a liberalization of international gas transmission tends to increase the differences in marginal willingness to pay for gas across countries in the short run. This type of result is known from the second-best literature: if a change (liberalization of all markets) that raises total welfare is split into several steps (several partial liberalizations), then each step (each partial liberalization) may not be welfare-improving— see, for example, Dixit (1975).

The present simulation study uses data from 2000, and hence compares the outcome after different types of liberalizations with the observed 2000 outcome. While it would have been desirable to use a more recent base year, using data from 2000 reflects partly that there is considerable lag in data production and publication. Typically, data for a year may be available after two-three years. Second,

Table 6
Partial liberalization of energy markets: gas is liberalized first (G) and electricity liberalized first (E); effects on welfare of each step (1000 billion USD).

		Consumer surplus in model countries		Producer surplus in model countries		International trader surplus		Sum model countries[a]		Sum all countries[b]	
		G	E	G	E	G	E	G	E	G	E
Short run	Partial liberalization in:										
	Electricity production	7.5	11.1	−2.4	−6.4	0.1	−0.9	4.1	3.9	0.6	0.8
	Domestic electricity retail	43.7	42.6	−36.6	−35.3	−3.5	1.8	2.9	4.7	10.5	9.9
	International electricity trade	3.6	4.4	−3.0	−2.3	0.6	−1.3	0.7	0.6	0.7	0.7
	Domestic gas retail	5.5	3.5	−2.9	−1.8	−1.9	−1.3	−0.8	−1.0	0.4	0.4
	International gas trade	−1.0	−2.4	−1.6	−0.7	−0.2	−3.3	−1.4	−2.7	0.0	0.3
	Total effect	59.2	59.2	−46.5	−46.5	−5.1	−5.1	5.5	5.5	12.0	12.0
Long run	Partial liberalization in:										
	Electricity production[c]										
	Domestic electricity retail	69.9	73.0	−48.4	−51.7	−2.8	−1.4	16.9	17.0	19.0	17.9
	International electricity trade	1.6	−3.5	−0.2	3.6	0.5	0.3	1.0	0.1	0.5	0.1
	Domestic gas retail	8.9	10.7	−9.8	−9.7	2.4	1.2	0.2	1.2	1.1	1.9
	International gas trade	0.1	0.2	2.0	1.4	−9.6	−9.6	−1.9	−2.2	−0.4	0.2
	Total effect	80.4	80.4	−56.4	−56.4	−9.5	−9.5	16.2	16.2	20.2	20.2

[a] Sum of consumer surplus, producer surplus and tax revenues to the government in the model countries, plus half the international trader surplus on each international transmission connection.
[b] Sum of consumer surplus, producer surplus, tax revenues to the government and international trader surplus in all countries.
[c] In the long-run version of the model, it is only possible to identify the combined effect of the liberalization of electricity production and the liberalization of domestic electricity retail.

updating and recalibration of a comprehensive model like LIBEMOD MP requires a lot of effort. Third, based on earlier experience of updating and recalibrating the model, the main results of a major policy change – like a liberalization – should not change very much. Still, it is possible that more recent data, for example, a data year with fossil fuel prices more in line with those of 2009, could have led to significantly different results. For an examination of the robustness of a full liberalization with respect to, for example, the crude oil price, see Aune et al. (2008a).

LIBEMOD MP mainly applies a bottom up modeling strategy, particularly for supply of electricity, which opens for larger effects than by imposing top down smooth supply curves, particularly in the long run. However, the experience in the energy markets underlines the fact that large shifts are also a feature of reality: for example, in 1995/6 the annual UK gas price dropped by roughly one-third, mainly because of major changes in the market structure.

LIBEMOD MP is a deterministic model, neglecting all types of uncertainties. One topic for future research is the impact of liberalization on the division of risk, which may differ across market segments. Such an analysis would be very challenging, requiring specification of the sources of uncertainties, for example, fossil fuel prices, weather conditions and supply interruptions, as well as the set of diversification opportunities of different agents. Such a framework would, for example, facilitate a theoretically satisfying examination of security of supply — before and after a liberalization.

Throughout the paper we have neglected the fact that liberalization causes higher emissions of CO_2 through increased use of fossil fuels, particularly in coal-fired power plants. Is there a net welfare gain of liberalization when this externality is taken into account? A complete liberalization increases global emissions by 315 Mt CO_2 in the long-run version of the model, which – according to our model – amounts to roughly 8% of CO_2 emissions in Western Europe. Because energy market liberalization in Western Europe increases annual global economic welfare by 20.2 billion USD, see Table 2, the model predicts that a full liberalization will raise global welfare (after taking into account increased CO_2 emissions) if the social cost of CO_2 emission is less than $\frac{315}{20.2} = 64$ USD per ton CO_2.

Typically, the international carbon permit price is estimated to be significantly below \$20 per ton CO_2 in the Kyoto period: see, for example, Springer and Varilek (2004). This suggests that a radical liberalization of the electricity and natural gas markets in Western Europe will raise global welfare even without a CO_2 policy. However, in order to maximize global welfare one should fully liberalize the Western European energy markets and also impose an optimal carbon tax. This exercise is beyond the scope of the present paper. However, if a uniform tax of \$12 per ton CO_2 is imposed in our model along with a complete liberalization, emissions are unchanged whereas economic welfare increases. Hence, a radical liberalization combined with a suitable taxation of CO_2 emissions will for sure raise global welfare.

Acknowledgment

Research support from the Research Council of Norway under the programs RENERGI and PETROSAM are gratefully acknowledged.

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