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The Elmar model:
output and capacity in imperfectly competitive electricity markets

Abstract

With the ongoing liberalization and integration of European energy markets and the increasing worries about security of supply, the need for thorough economic analysis of electricity markets is growing. We develop a model for the European electricity market, taking into account imperfect competition through conjectural variations, as well as imperfect international competition due to import capacity restrictions. The model distinguishes between competition on the output market and competition in capacity investments. We find that the least competitive of these determines wholesale prices.

1 Introduction

The integration and liberalization of European electricity markets brought about a great number of changes to the sector. Coming from a heavily regulated situation of government owned regional and national monopolies, electricity producers will now have to compete for market shares and profits. This new situation brings about a lot of uncertainty, both for producers and for regulators and policy makers.

At the same time, recent outages in the US and several European countries have fuelled fears about security of supply. Will liberalized electricity markets provide sufficient supply security for a good as vital as electricity? Will the damage caused by business cycles be limited to price spikes or will we experience frequent black-outs in the near future? What role should the government play in securing supply in a liberalized market? The challenge lies in reaping the benefits of competition without having to suffer from severe side-effects.

These recent changes in the structure of the electricity market have induced a sprawl of economic research, with a wide range of differing model applications. Green and Newberry (1992) develop a supply function equilibrium model of the British spot market, whereas Boom (2003) focuses on capacity investment in Germany. Von der Fehr and Harbord (1997) develop a game-theoretical model of capacity investment, focussing on decentralized markets. A recent overview of other electricity market models, focussing on the bidding process, may be found in David and Wen (2000).

The model discussed in this paper describes both competition in output and capacity investment decisions. As in real life, decisions regarding output and capacity are interrelated in the model. Using a conjectural variations approach, we allow for differences between long term and short term competitiveness of the market. Furthermore, cross border restrictions are explicitly modelled, to take into account their impact on competition between producers from neighbouring countries.

The purpose of the model is to predict investment levels and electricity prices in the liberalized electricity market. The model may be used to look into issues related to security of supply, as well as questions regarding institutional design. Policy measures in both fields may be added to the model to assess their effects on scarcity and prices.

This Memorandum is written for policy makers and researchers who are interested in electricity markets, as well as for those interested in building electricity market models. Technical details for the latter are included in appendices. The remainder of this paper is organized as follows. Chapter 2 briefly describes the electricity market and the issues currently under attention. In chapter 3, we discuss how our model deals with the market structure of the electricity market, followed by a formal description of the model itself. Data and calibration are discussion in chapter 5, followed by a numerical example to illustrate the model in chapter 6. The appendices contain the technical details of the model.

The authors thank Rob Aalbers (OCFEB) and Machiel Mulder (CPB), who advanced our understanding of modelling the electricity market. Rob drew our attention to Borenstein et al. (2000) (see appendix A) and to the possible substitution of electricity consumption over time (see note 9). We also like to thank Bert Smid (CPB) for valuable comments to an earlier version of this Memorandum. All remaining errors are ours.

2 The electricity market

2.1 Introduction

This chapter gives a broad overview of the electricity market, its institutional setting and some of the current issues of interest. Section 2.2 describes the product characteristics of electricity, followed by a brief description of market segments and players. We discuss the types of markets electricity is traded on in section 2.4. The following two sections of this chapter discuss the liberalization and integration of European electricity markets and the issue of supply security. We conclude by briefly summarizing the role of electricity market characteristics in our model.

2.2 Product characteristics

We start this chapter by describing several product characteristics of electricity. These product characteristics are essential for understanding the economics of electricity markets. First of all, electricity can not be stored. In discussions with electricity specialists, it is often heard that electricity is a unique product because of this characteristic. We would like to stress however that it shares this unique characteristic with virtually all services. It is impossible to stockpile taxi rides or to build up a collection of medical services. Likewise, one cannot purchase a ballet performance and store it for later use. All these products and many more are, like electricity, consumed at the same time they are produced.

Another important characteristic of electricity is that the demand for electricity is often derived demand. We do not need electricity for its own merits, rather we need it to facilitate consumption of other goods, leisure or productive activities. If for instance, one would like to consume a television programme, electricity is needed to do so. Therefore, the demand for electricity follows from demand for other goods and services, as well as from decisions on how time is divided between leisure and work. This implies that the consumption of electricity is related to our daily patterns, which is also mentioned regularly as one of the unique characteristics of electricity. Again, this characteristic is not as unique as it may seem. Transportation is another clear example of a good with a recognizable time-of-use pattern.

A third characteristic that is of interest is that energy is transported through networks. These networks have the special feature that only the net flow of electricity from A to B has to be transported physically. This is relevant for the maximum capacity of a connection between two between regions. Also, the electricity flows autonomously, ruled by the laws of physics. More or less like water pumped through a water supply system. The economic implication is that this feature complicates the possibility to exclude users from consumption, although this is still possible by making technical adjustments at the exit(s) of the network.

2.3 Market segments and players

The provision of electricity to end users takes place at several levels. These levels differ in the type of trader involved as well in the type of network used to deliver the energy to the customer. Typically, electricity is transported through the national high voltage network and through regional networks at a lower voltage. The former is called the transmission grid, the latter are known as distribution networks. Very large users receive their electricity straight from the transmission network, which is operated by the Transmission System Operator (TSO). The Dutch TSO, Tennet, is a state-owned company with no ties to any of the producers or traders.

Large and very large users buy their electricity from wholesalers or directly from producers, whereas small users buy their energy from retailers. Wholesale and transmission are organized on a national (sometimes international) level, whereas retail and distribution take place on a regional level. A region's location and borders follow from the historical development of utility regions. The regional character of competition does not imply that retail is limited to regional companies. Retailers may be active in more than one region and even engage in competition in regions in other EU countries. Obviously some regions may be more attractive for retailers to compete for than other regions (e.g. because of higher density), which may result in regional differences in the number of retailers.

Small and large users pay different prices for their electricity because these prices consist of different components. Large users receive their energy from wholesalers directly from the transmission grid, implying they pay for the commodity, wholesale costs and margins and transmission costs and margins. Small users buy their energy from retailers, adding distribution costs and margins as well as retail costs and margins to the price.

2.4 Types of markets

In order to understand the pricing mechanisms in the electricity market, let us devote some attention to how electricity is traded. The lion's share of electricity is traded through bilateral contracts between users and suppliers. This is sometimes also referred to as the over-the-counter (OTC) market. Some general information, like traded volumes and average price levels, are known, but the contents of bilateral contracts are not public information. Some of those contracts have fixed prices, others may be linked to the spot market price, either real-time or based on averages over time. As noted above, small end users are supplied by retailers, often on bilateral contracts with standardised terms and a fixed per unit price.

Some 15 percent of electricity is traded or resold on the spot market. On this market, organized in The Netherlands by the Amsterdam Power Exchange (APX), buyers and sellers of electricity bid their offers 24 hours ahead of delivery. Prices are set on an hourly basis. After the spot market has closed, trade volumes for the following day are known. Traders, formally load serving entities, report their total trade volumes, consisting of bilateral contracts and spot market trade, to the TSO. Each load serving entity is responsible for serving as much load into the network as it takes from the network. If the load serving entity does not succeed, this causes imbalance.

If imbalance occurs, the necessary condition that supply meets demand real time is not met and the TSO has to act to keep the system from breaking down. To this end, the TSO calls in more productive capacity from producers, which was bid into the single buyer market in advance. The TSO orders the bids from low to high priced ones and deploys the units in this order if necessary. If a unit of capacity is used to retain balance, the owner of the unit is paid the imbalance price, which is paid for by the load serving entity causing the imbalance. Unlike the spot market price, the unbalance price is a real-time price.

2.5 The integrated European electricity market

Europe has a long history of government-owned utilities, exercising their local or national monopolies against a background of country-specific regulatory regimes. With the further economic integration of Europe's economies in the European Union, this was a situation that could no longer be sustained.

Aiming for liberalization and integration of Europe's electricity market, the European Parliament and Council Directive for electricity (96/92/EC Electricity Directive) was adopted. A free and integrated European electricity market is thought to increase efficiency of allocation of resources, thus increasing welfare. The increase of competition in the electricity markets should lead to convergence of prices among EU member states, preferably below their current levels.

Following the integration of Europe's former national electricity markets, electricity firms started integrating as well. The largest European utilities (EDF, E.ON, RWE, Enel, Vattenfall, Endesa and Electrabel) started a wave of mergers and acquisitions both in the EU member states and in the (then) candidate countries. The increase in concentration, resulting from these mergers and acquisitions, probably leads the integrated European electricity market away from the goals of liberalization.

So far, the European Union and its member states have not induced policy measures to counteract the increase in concentration. Possible policy measures include blocking mergers or even splitting up large companies, as was done in the UK in the 1990s.

Concentration will not be a problem by itself if entry is entirely free. In that case, excess profits would induce entry, thus decreasing the level of concentration. In reality however, entry is not entirely free. Formally, all barriers to entry are lifted, as the electricity directive states that '... new entry must be permitted under the transparent, objective and non-discriminatory terms of an authorization procedure.'

Some barriers to entry have remained however. Favourable locations for generating plants are scarce and often already owned by the incumbents. Furthermore, some of the knowledge used in the process of generating electricity is very specific and therefore hard to come by for entrants. Both barriers are relatively unimportant however and are not likely to deter entry to a great extent.

A more important barrier to entry consists of imperfections in the capital market, in combination with the large asset base of incumbents. This combination yields credible grounds for predatory behaviour and limit pricing by incumbents. Furthermore, it may hinder entrants from starting their operations at the desired scale, leaving them more vulnerable to market volatility.

Besides the barriers to entry mentioned above, several market failures apply. An important source of market failure in energy markets is the existence of externalities; costs or benefits that are ignored by markets in the determination of prices. Imperfect information is also an important form of market failure, especially when it comes to observing real-time prices. Furthermore, some problems related to natural monopoly may be imported from the downstream market, since all producers are connected to a single network.

The existence of market failure may give rise to government intervention. One should keep in mind however that the counterpart of market failure, regulatory failure, may lower the benefits of government intervention or even turn them into a net cost. Regulatory failure may result from governments having insufficient information regarding the market, diverging objectives between government and private firms and non-welfare-maximising objectives of the government (Helm et al. (1988)).

2.6 Security of supply

Supply security is currently one of the main issues in electricity markets, mainly because of a number of crises and near crises in the first years of this century, the California crisis being the most notable one. Recent outages in the US, Canada, England, Denmark, Greece and Italy have further emphasized both the importance for modern day society and the vulnerability of power systems.

One of the goals for the move to a liberalized market was to increase efficiency in electricity production, which was partly to be reached through a decrease of (mostly-idle) generation capacity. If the newly liberalized electricity market succeeds in matching demand and supply efficiently, the decrease in spare generation capacity is the correct response to market signals. These signals may consist of high peak load prices, serving as an instrument for efficient rationing as well as a mechanism for financing investments in capacity. Price spikes are however relatively new to electricity markets, coming from a state of regulated public monopolies with heavy overcapacity, and they may scare politicians, tempting them to adopt protective policies. These policies will however run the risk of being counterproductive with respect to security of supply, as the California crisis has shown.

From an economist's point of view, security of supply problems come from congestion externalities. The key problem is that the demand for electricity is time-varying, whereas supply is limited in the short run by capacity constraints. The combination of time-varying demand and fixed short run supply is shared by many services, obvious examples being transport and medical services.

To take transport as an example, supply is limited by the existence of roads, whereas demand varies over the day, often leading to congestion during rush hours. Congestion is an externality, as adding one unit of demand above a certain threshold level has a negative impact on the quality of the good for all users. Marginal customer are not charged for all the costs they incur. A similar line of reason holds for electricity; an increase in demand beyond available capacity levels increases the probability of a black-out, thus imposing costs on all users.

Externalities may be counteracted either by pricing or by granting (tradable) ownership rights. If all externalities are internal to the market at stake (i.e. users impose costs on each other, as is often the case with congestion), optimal taxation will often take the form of peak load pricing. The spot market and the unbalance pricing mechanism provide a form of peak-load pricing in the electricity market. Many consumers however do not observe real-time prices and hence cannot react to them.

Two other issues are related to security of supply. First, uncertainty in the electricity market slows down investments. Uncertainty originates from unclear prospects regarding European and national competition and environmental policies. Although uncertainty hampers investments, this is not really a security of supply problem. An increase in uncertainty will increase the risk premium in capital costs and hence increases prices. Although the equilibrium outcomes change, security of supply will not be affected. The second issue to be discussed here concerns business or investment cycles. These cycles occur if investment reacts slowly to demand developments. Growing demand at fixed capacity causes prices to rise, inducing investments. The resulting increase in capacity causes prices to decrease, which in turn slows down investment. Investment cycles are a common feature in industries with high fixed costs and are no real threat to security of supply, provided that the price mechanism works well. If producers are well-informed on demand developments, they can anticipate and cycles are less likely to occur.

The increasing concern for security of supply has led governments throughout the world to investigate or implement policy measures. One of the simpler measures is to subsidize capacity. Systems like this, labelled capacity payments, are in place in Spain and several Latin American countries.[1] Subsidies apply to all available capacity, rather than spare capacity alone. Since capacity now needs a lower load factor to be profitable, construction of capacity for supra-normal peaks may become economically viable as well. According to Ford (1999), capacity payments prevent business cycles in capacity investments and long run prices will not rise. It should be noted however that his result is based on a theoretical model, assuming perfect competition. Oren (2000) shows that capacity payments are an inefficient way of promoting supply adequacy, and more efficient alternatives are almost always available.

One of these alternatives is known as capacity markets, with its well-known application in Pennsylvania-Jersey-Maryland (PJM). The system, named Interconnection Installed Capacity (ICAP) requirement, consists of a requirement to back peak demand plus a prescribed level of spare capacity with contracted capacity, allowing for bilateral trade of units of capacity at a secondary market. Trade on this market generates revenues for production capacity, even if it is not dispatched. The market mechanism makes sure that spare capacity is offered by those producers that can offer it in the most efficient way. The market mechanism also makes sure that spare capacity in excess of the requirement does not receive any payments.

Hobs et al. (2001) conclude that under the assumption of a competitive market, the PJM-ICAP system is likely to induce sufficient capacity investment, without increasing the long run cost of power. Stoft (2000, p.8) notes that the assumption of a competitive market does not hold and that the capacity market '… has provided yet another arena for the exercise of market power.' Furthermore, capacity markets could likely import price spikes from neighbouring regions without an ICAP-system in place.

A system similar to capacity markets is that of reserve contracts, the main difference being that auctions rather than the secondary market are used to guarantee efficient market outcomes.

[1] See Oren (2000). A similar system was recently abolished in England and Wales.

The Transmission System Operator (TSO) buys production units from producers, extracting these reserves from use for generating electricity for the regular market and dispatching them in case of an emergency. The costs of keeping spare capacity are charged to consumers using the system fee.

2.7 Modelling electricity market characteristics

It would obviously be impracticable to incorporate all of the issues and characteristics of the electricity market into our model. The model is limited to the production sector, thus ignoring retail and sales to end-users. Likewise, we also ignore so-called autoproducers, electricity users producing (a part of) their own electricity, mostly by combined heat and power generation.

The non-storability of electricity is modelled explicitly in the model by letting capacity limit output, whereas the time-of-use pattern is incorporated in the model through the data. In terms of market segments, the spot market plays a central role in our analysis, as this is the place where hour-to-hour trade is conducted. Nevertheless, price and elasticity data used refer to the entire market rather than the spot market alone. Competition on the EU-level is also modelled here, especially its limitations through cross border transport capacity restrictions.

3 Modeling market structure and conduct

3.1 Introduction

This section discusses how we modelled the market structure in electricity markets. We set out by explaining why the Cournot model is not appropriate for modelling competition in the electricity market. Section 3.3 discusses alternative ways to model market structure and conduct. We finish this chapter by presenting the values for the conduct parameters applied in our model.

3.2 Why the Cournot model does not fit the electricity market

A widely used model for a market with few suppliers (oligopoly) is the Cournot model[2]. In this model each firm thinks it can raise the price above marginal costs by decreasing its supply without the other firms taking advantage of this price raise by increasing their supply.

The other extreme is the Bertrand model of oligopoly, where each firm thinks there is no point in trying to raise the price above marginal costs because surely the other firms will take advantage of this price raise by increasing their supply (and thereby undoing the price raise). This model gives the same result as perfect competition.

In the Cournot model with identical firms the marginal revenue is

$$p\left(1-\frac{1}{-\varepsilon N}\right) \tag{3.1}$$

where ε is the price elasticity of demand (with $\varepsilon < 0$) and N is the number of firms. With $-\varepsilon N < 1$ the marginal revenue becomes negative and the Cournot model breaks down[3].

With marginal revenue from equation (3.1) equal to marginal costs λ we get a Lerner index p/λ as follows:

$$\frac{p}{\lambda} = \frac{1}{1-1/(-\varepsilon N)} \tag{3.2}$$

It follows that prices are higher with fewer firms and with less elastic demand.

Coincidentally in the Dutch electricity market the right-hand-side of (3.2) is approximately $1/(1-1/0.25\times 4)) = 1/(1-1) = \infty$, with four large firms and an elasticity ε of approximately -0.25 [4]. Hence the Cournot model is useless during the hours when the connection between The

[2] The previous version of Elmar used the Cournot model. See Lijesen and Mannaerts (2002).

[3] This is easily seen in the monopoly case with $N = 1$. Let the demand be inelastic: $(-\varepsilon) < 1$. Then one percent increase in price is obtained with less than one percent reduction of supply, giving a net increase in the monopolist's revenues. This cannot be an equilibrium: why not reduce supply, and have both less costs and more revenues?

[4] See Koopmans et al. (1999), table 3.3. See section 5.4 for the breakdown of the elasticity between large users and small users, as used in the actual computations.

Netherlands and its neighbours is congested and the Dutch firms have no foreign competition. More in general, observed moderate p/λ ratios cast doubt on the Cournot model in electricity supply; see the extensive discussion in Stoft (2002) starting at p.347.

3.3 Conjectural variations and supply functions

The theory of conjectural variations assumes that each firm anticipates (conjectures) a reaction (variation) by its rival(s) and was originally developed by Bowley (1924). Consider a simple duopoly model with firms maximizing profits. The profit of firm 1 is defined as:

$$\pi_1 = q_1 p(q_1 + q_2) - c(q_1) \tag{3.3}$$

with $p(q_1 + q_2)$ being the inverse demand function and $c(.)$ denoting the cost function. Defining marginal costs as λ and stating that $q = q_1 + q_2$, we may write the first order condition for firm 1 as:

$$\frac{\mathrm{d}\pi_1}{\mathrm{d}q_1} = p + q_1 \frac{\mathrm{d}p(q)}{\mathrm{d}q}\left(1 + \frac{\mathrm{d}q_2}{\mathrm{d}q_1}\right) - \lambda(q_1) = 0 \tag{3.4}$$

In equation (3.4), $\mathrm{d}q_2/\mathrm{d}q_1$ represents the conjecture of firm 1 about the reaction of firm 2. This conjecture is generally written as v, so that equation (3.4) becomes:

$$p + q_1 \frac{\mathrm{d}p(q)}{\mathrm{d}q}(1 + v) - \lambda(q_1) = 0 \tag{3.5}$$

Conduct parameter v covers the entire range between competitive and collusive behaviour, with $v = -1$ representing Bertrand competition, $v = 0$ representing Cournot behaviour and $v = 1$ depicting collusion (which is equivalent to monopoly).

The main criticism against models using conjectural variations is that they are based on inconsistent beliefs if used in a multiperiod setting. In a multiperiod conjectural variations model, the outcome in one period may differ from the outcome in the other period, even though the same conditions apply. This implies that the equilibria in both periods are not consistent.

A way around this is to define the model in such a way that only consistent conjectural variations are allowed (see Perry (1982)).

A more elegant alternative to model reactions of rivals is through the use of supply functions. In this approach, a firm's strategy does not exist of a single point. Rather, it is represented by a supply function[5] $q_i = S_i(p)$. These functions are then used to construct the non-cooperative Nash equilibrium, or the supply function equilibrium (SFE).

[5] Equation 3.5 may also be viewed as a supply function. The difference here is that in the supply functions approach v is not defined as a reaction function, but by the requirement of a Nash supply function equilibrium: no firm could have had more profit if it had chosen another value of v, given the v values of the other firms.

Klemperer and Meyer (1989) introduce uncertainty as a motivation for supply functions. They state that in a world of uncertainty firms may not want to commit to either price (Bertrand) or quantity (Cournot) competition. Instead, firms would rather set a supply function to adapt to changing conditions. A supply function implies a decision on a set of price and quantity pairs, based on the demand function and competitors' supply functions.

Green and Newberry (1992) note that supply function equilibria (SFE) are appropriate for describing electricity spot markets. Prices are determined on a day-ahead basis, with suppliers submitting bids existing of a schedule of prices for separate supply units. This is very much comparable to a supply function, where suppliers determine a set of price-quantity pairs. The main problem with SFE is the multiplicity of possible equilibria. An infinite number of supply functions may be constructed, rendering this approach impracticable for numerical simulations. [6]

To get around this problem, we return to the use of conjectural variations, despite their theoretical drawbacks. We try to retain consistency with results from studies based on SFE, as well as with results from empirical studies regarding market types. Similar approaches are used in empirical studies regarding the degree of oligopoly power (e.g. Appelbaum (1982); Iwata (1974); Bresnahan (1987)).

3.4 Values for conduct parameters

Klemperer and Meyer (1989) show that supply functions equilibria (SFE) lie between Cournot (steep supply function) and Bertrand (flat supply function) outcomes. They find that several factors influence the slope of the supply function. If the number of firms is small, the SFE will be close to the Cournot outcome, whereas a larger number of firms implies a flatter supply function. In a market with differentiated products, the supply function will be steeper, while Bertrand-like outcomes are to be expected if goods are homogeneous.

Several authors (Vives, 1999; Bresnahan, 1981) stress the effect of the slope of the cost function on reaction functions. Steep cost curves are associated with Cournot-type behaviour, whereas a flat cost curve is conducive to Bertrand-like behaviour. Klemperer and Meyer (1989) slightly adjust this by stating that a marginal cost curve that is steep relative to the inverse demand curve leads to a stronger tendency towards Cournot-type behaviour. From the observations above, we may formulate conditions under which Bertrand- or Cournot-type markets are more likely. We summarize these conditions in the table below.

Electricity markets typically form a mix of these conditions. The number of firms is

[6] Likewise, the use of a multi-stage game solution would not be useful for numerical simulations.

Table 3.1 Conditions for the likeliness of Bertrand or Cournot type of markets

	Cournot more likely	Bertrand more likely
number of firms	small	large
degree of product homogeneity	low	high
uncertainty of demand reactions	at high price levels	at low price levels
slope of marginal cost relative to inverse demand	steep	flat

generally low and the product is (almost) perfectly homogeneous. The demand function is relatively steep compared to marginal costs, but less so in peak periods, where the marginal cost curve starts climbing because more expensive units come into use. Further note that capacity decisions are based on long run incremental costs, which have a flatter slope than short run marginal costs. This implies that capacity is more likely to be determined in a Bertrand way, whereas the output market is probably more Cournot oriented. This combination may lead to prices well in excess of marginal costs, but only slightly above incremental costs, which may resemble limit pricing if viewed from a distance.

Based on the above, we introduced a parameter which allows us to make a numerical choice somewhere in between the Cournot model and the Bertrand model. The crucial quantity $1/(-\varepsilon N)$ is multiplied with a factor between zero and one, giving a continuous scale from Bertrand to Cournot, respectively. Note that this parameter coincides with $1+v$ in the conjectural variations theory. Values for this factor are $g = 0.2$ (for the output decision of firms in equation (4.7)) and $G = 0.1$ (for the investment decision of firms in equation (4.13)) respectively. These values imply a fairly, but not totally competitive market and are based on outcomes in tables 3.4 and 3.5 of Scheepers et al. (2003), with prices and marginal costs for Germany and The Netherlands, respectively.

4 The formal model

4.1 Introduction

This chapter describes the present version of Elmar, the CPB model of the electricity market[7].

Section 4.2 describes the demand side of the model. Section 4.3 describes the various techniques of producing electricity and the related marginal costs. Equating the latter to the marginal revenue gives the production level which is optimal for the firm, given the production capacity. Finally, sections 4.5 and 4.6 describe the firm's optimal production capacity. This also defines optimal investment.

Elmar is a comparative static model: any change in an exogenous variable has its effect in the same year or the next year, since no gradual adaptation to shocks is modelled and any change in an exogenous variable is foreseen by the firms which build production capacity. The model is driven by the growth of demand over time. Elmar is also a model in which the electricity market always clears, due to the response of demand and supply on the wholesale market.

In the rest of this section the notation is presented. Let q_{hikl} denote the quantity of output produced at hour h by firm i in region k which is supplied to region l. We ignore the possibility that a firm in one region may be owned by a firm in another region. All firms in any particular region are assumed to be identical. Hence the subscript i is not used to indicate a specific firm but to distinguish between the output of one firm and the output aggregated over firms. See the table below.

Table 4.1 The subscripts in the model

symbol	description	number of values in the present model version
h	hour of the day	24
i	firm	4
k	region of production	2
l	region of consumption	2

Note that there is no index for the day of the year. All days are taken together. Hence the 24 hours h together are one year. The number of firms is given for The Netherlands.

[7] The model was applied and briefly described in De Joode et al. (2004, Appendix 7) and in Lijesen (2004, chapter 4). Here we present more detail and more explanation. We also try to further improve the notation, and some mistakes in the description are corrected. The same work is also reported in Lijesen and ten Cate (2004). The model is also applied in Lijesen and Vollaard (2004).

Aggregation of output (or capacity) over subscripts is indicated by omitting subscripts[8]. For example:

$$q_{hl} \equiv \sum_i \sum_k q_{hikl} \tag{4.1}$$

is the output which is sold in region l at hour h by all firms i in all regions k. Prices have one or two subscripts: the region l and possibly the hour h.

Finally, as we shall see below, next to the lower case letter q denoting the size of the output there is the upper case letter Q denoting the size of the production capacity. This distinction between output and capacity reflected in the case of the letter also holds for other variables introduced below.

4.2 Demand

The demand at hour h in region l comes from large users (L) and from small users (S):

$$q_{hl} = q_{hl}^L + q_{hl}^S \tag{4.2}$$

The quantity q_{hl} is sold on the wholesale market at a single price p_{hl}. The large users have a linear inverse demand function, relating this price to the quantity demanded[9]:

$$p_{hl} = a_{hl}^L - b_{hl}^L q_{hl}^L \tag{4.3}$$

This price clears the wholesale market in that region at that hour. Hence we model the entire wholesale market as a single spot market.

The small users pay a retail price to retailers who buy the required quantity on the wholesale market. The retail price is equal to the average wholesale market price of last year, plus a retail margin and tax. Hence the small users' demand is independent of the current wholesale price[10]. The small users have an indirect demand function similar to (4.3):

$$p_l^S = a_l^S - b_l^S q_l^S \tag{4.4}$$

where p_l^S is the retail price in region l and q_l^S is the annual consumption of the small users in region l. The latter is distributed over the 24 hours h using an exogenous hourly consumption

[8] In this way a particular value such as q_{12} has no meaning, since it is unclear which subscripts are omitted. However, in this paper only symbolic subscripts are used.

[9] Note that in the present version no substitution between hours is assumed, as in professional cooling and freezing where electricity consumption can sometimes be put off a few hours, until the price has decreased.

[10] This creates a time lag of one year in the reaction of small users to price changes. This may create short hog cycles. However, we did not observe these; possibly because of the ever growing demand.

pattern. Note that the small users pay one price independent of the time of use; hence we assume that there is no time of use pricing schedule.

The coefficients b^L_{hl} and b^S_l vary inversely with the assumed demand growth over the years[11]. The latter is somewhat larger than the growth of the national income. Also these coefficients vary over the hours h inversely with the observed hourly time path of the volume of electricity use[12].

No forward contracting is modelled here. Also, the autoproducers (agricultural and industrial firms which produce their own electricity) are not modelled. This is left for further work.

4.3 The production techniques mix and the marginal costs

The model distinguishes between five techniques for the generation of electricity: gas-fired, coal-fired, nuclear, large scale hydro, and other renewables.

There is a theoretically optimal combination of these techniques. This combination gives each technique a percentage share in the MW production capacity, such that total cost are minimized.

However, before we explain this theory, it must be noted that in practice the techniques mix depends on much more than costs alone. Coal-fired generation is regulated because of its negative environmental impact. Nuclear power generation has been controversial for decades. Hence in the model the techniques mix is given at the start of any time path and for simplicity all new capacity is assumed to be gas-fired, by far the most important technique in The Netherlands. See also Ford (1999). See chapter 5 below for statistics.

The theory of the least-cost combination is nevertheless presented here because it is related to the discussion of marginal costs below. The theory may also be interesting from a historical point of view, as an important part of the traditional electricity economics, combining the typical characteristics of electricity production: (practically) non-storable, fluctuating over time, and capital intensive.

The theoretical least-cost combination of the generation techniques is based on the fact that the techniques differ in building costs per kW capacity, and also in variable costs per kWh[13]. For simplicity we assume for a moment that variable costs are fuel costs only and that only two

[11] We have modelled the demand growth over time simply as a growth of the customer base. Note that the demand of two identical consumers taken together has the same a coefficient as one consumer, but only one half of the b coefficient: if $q = (a-p)/b$ then $2q = 2(a-p)/b = (a-p)/(b/2)$. See also section 5.5 below.

[12] Of course these ex post observed volumes underestimate the unknown ex ante variation in the demand functions by hour: the ex post variations are dampened by the price variations which they create.

[13] In the previous version of Elmar, described in Lijesen and Mannaerts (2002), the techniques mix was modelled differently, with two quadratic total cost functions for each technique.

techniques exist: gas-fired and coal-fired.

Using coal is cheaper per kWh than using natural gas. Hence in the least-cost situation all available coal-fired capacity is used all the time[14]. Only at peak hours, when more capacity is required than the coal plants can deliver, gas-fired plants are used. Building a gas-fired plant is cheaper per kW than a coal-fired plant. The optimum share of coal-fired production capacity in the total production capacity depends on the length and height of the peaks, and on the various costs[15].

Marginal costs

In the model, short run marginal costs (SRMC) are determined by the technique mix, as follows. Firms will always use the production technique with the lowest variable costs, given the production capacity of the various techniques. If the capacity of this technique is insufficient at some particular hour, then they also use the production technique with the next-to-lowest variable costs, etcetera. The last technique used in this way is the marginal technique: its variable costs is the short run marginal costs of production. This creates a staircase shape of the marginal costs[16]. The techniques are said to be used in their merit order.

In order to increase the robustness (and realism) of the staircase model, we smooth this shape as follows: a piece-wise linear curve is drawn through the midpoints of the vertical sections of the staircase. At the top of the staircase we need one more vertical section; we give it the same height as the previous one. See graph 4.1 below, for The Netherlands[17]. In the next sections

[14] Note that in the least-cost combination, the technique with the lowest variable costs produces the entire so called base load. In The Netherlands the four techniques with the lowest operation costs together are not enough to produce the base load. This suffices to show that this optimizing theory is not applicable.

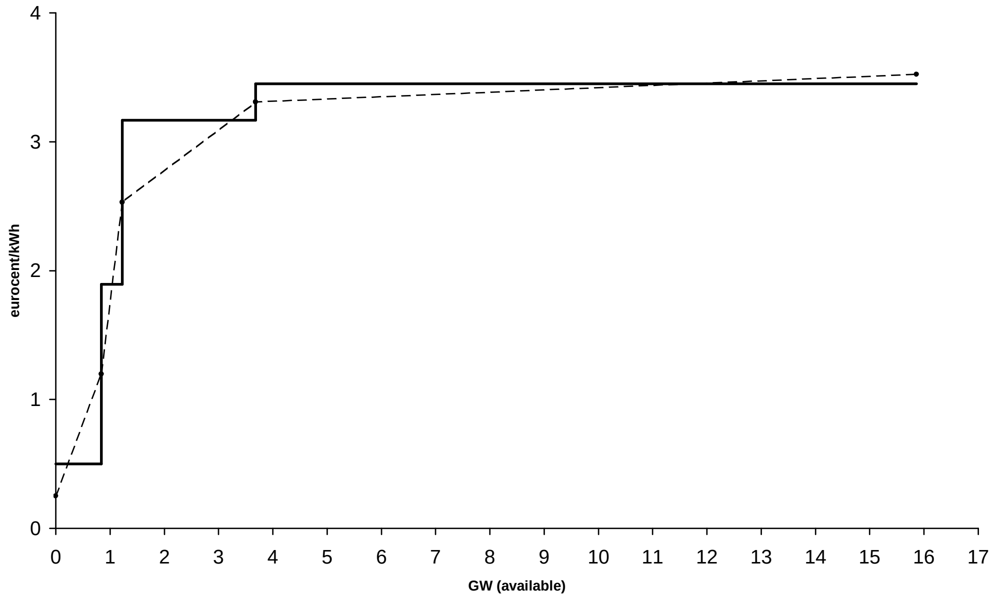
[15] This is usually demonstrated graphically; see Schweppe et al. (1988, pp.307–309), Stoft (2002, pp.35 and 45), and Hunt (2002, pp.403–415). In a formula: the coal-fired capacity is such that only during a fraction t of the time more capacity is required than the coal plants can deliver, where t is defined by the break-even equation $C_{\text{coal}} + t\lambda_{\text{coal}} = C_{\text{gas}} + t\lambda_{\text{gas}}$, or $t = (C_{\text{coal}} - C_{\text{gas}})/(\lambda_{\text{gas}} - \lambda_{\text{coal}})$. The C are the annuitized building cost per kW per year and the λ are the variable costs per kWyear instead of per kWh. If not $0 < t < 1$ then one technique is the overall cheapest and the other technique is never used.

[16] This staircase model has already been used in the electricity industry for a long time. See the diagram at OEEC (1958, p.40). An alternative model assumes flexible capacity instead of rigid capacity: all techniques are used all the time, up to the point where their marginal costs are the same. See for instance Grainger and Stevenson (1994, p.540). This has approximately the same result as a “smoothed” staircase model.

[17] This graph is without hydro production, being so insignificant in The Netherlands that it would be hardly visible. The graph differs somewhat from the similar graph at page 28 in Scheepers et al. (2003). The latter depicts individual generators, with a level below 3 eurocent/kWh at the start of the “gas segment” which increases more or less gradually to over 4 eurocent/kWh.

these marginal costs are indicated as λ_{hik}: the marginal costs at hour h for firm i in region k[18].

Figure 4.1 Marginal costs staircase and smoothed line for renewables, nuclear, coal and gas (NL, 2000)



4.4 Short run optimal output

The short run profit of firm i in region k at hour h is as follows, omitting everything which is given in the short run:

$$\pi_{hik} = \sum_{l} p_{hl} q_{hikl} - c_P(q_{hik}, Q_{ik}) - \sum_{l \neq k} c_T(q_{hikl}) \tag{4.5}$$

Here the function $c_P(q_{hik}, Q_{ik})$ indicates the short run costs[19] of producing q_{hik} while the production capacity equals Q_{ik}. The function $c_T(q_{hikl})$ indicates the costs of transporting q_{hikl} from region k to region l. Note that lower case letters π, c, q and g denote short run output related variables, while upper case letters Π, C (both introduced below), Q and G denote capacity related variables.

[18] Of course λ_{hik} is a function of production volume q_{hik}. This function depends on the region k, since fuel costs differ between regions. Hence the proper way to denote this would be $\lambda_k(q_{hik})$, which we mercifully abbreviate to λ_{hik}. In the nutshell model in section 4.5 below the symbol λ_h is used, as there are no regions k and no firms i there.

[19] Note that the letter c does *not* indicate per unit costs here, unlike in De Joode et al. (2004, Appendix 7) and in Lijesen (2004, chapter 4). This simplifies the first-order conditions considerably.

For the moment we ignore the possibility that production capacity is a binding restriction on the output; this will be discussed at the end of this section. The first-order conditions for a maximum[20] of (4.5) are found by differentiating with respect to q_{hikl} and equating the result to zero:

$$\begin{aligned} p_{hl} + \frac{\partial p_{hl}}{\partial q_{hikl}} q_{hikl} &= \frac{\partial c_P(q_{hik}, Q_{ik})}{\partial q_{hik}} \frac{\partial q_{hik}}{\partial q_{hikl}} + \sum_{l \neq k} \frac{\mathrm{d}c_T(q_{hikl})}{\mathrm{d}q_{hikl}} \\ &= \frac{\partial c_P(q_{hik}, Q_{ik})}{\partial q_{hik}} + \sum_{l \neq k} \frac{\mathrm{d}c_T(q_{hikl})}{\mathrm{d}q_{hikl}} \\ &\equiv \lambda_{hik} + \sum_{l \neq k} \tau_{hkl} \end{aligned} \tag{4.6}$$

Here λ_{hik} indicates the short run marginal production costs at hour h of firm i in region k, as described in section 4.3 above. The variable τ_{hkl} is the tariff of transporting power at hour h from region k to region l. This tariff is computed in an equation, such that it equals the fixed tariff (the so called “postage stamp” tariff) or the tariff which brings demand for transmission at hour h down to the available transmission capacity, whichever is highest. The latter may be the result of an auction. (We ignore here the difference between the marginal tariff and the actual tariff.)

The expression $\partial p_{hl}/\partial q_{hikl}$ in the left-hand-side of equation (4.6) indicates how much the wholesale market price is influenced by one firm. Following section 3.3 above, we introduce a parameterization of the difference between the Cournot model and the Bertrand model:

$$\frac{\partial p_{hl}}{\partial q_{hikl}} = (1+v)\frac{\mathrm{d}p_{hl}}{\mathrm{d}q^L_{hl}} \equiv g\frac{\mathrm{d}p_{hl}}{\mathrm{d}q^L_{hl}} = -gb^L_{hl} \tag{4.7}$$

Equation (4.7) is substituted into equation (4.6), giving:

$$p_{hl} - gb^L_{hl} q_{hikl} = \lambda_{hik} + \sum_{l \neq k} \tau_{hkl} \tag{4.8}$$

Equations (4.1), (4.2), (4.3), (4.4), and (4.8) together determine the $4HL + HKL$ variables q_{hl}, q^L_{hl}, q^S_{hl}, p_{hl}, and q_{hikl}. The upper case letters indicate the number of values of the respective lower case subscripts, with $K = L$ of course.

With $g = 0$ substituted into equation (4.8) we get the competitive result:

$$p_{hl} = \lambda_{hik} + \sum_{l \neq k} \tau_{hkl} \tag{4.9}$$

with price equal to marginal costs (including transport costs). Now assume for a moment that equation (4.9) holds: output is optimal with perfect competition. Next we introduce oligopoly,

[20] See appendix A for a discussion of how the use of first-order conditions saves us from the problem of Borenstein et al. (2000).

with the g term in equation (4.8). Then marginal revenues are lower than marginal costs, and the firm will reduce output until a new optimum for the firm is reached. Thus the result of imperfect competition is a lower level of production – which is of course the natural result of oligopoly.

Note that production capacity Q_{ik} puts a restriction on output q_{hik}. Technically this can be viewed as the marginal costs λ_{hik} going up vertically[21] at $q_{hik} = Q_{ik}$. Then the supply curve also goes up vertically at that point. During the hours when this capacity restriction is binding, the price rises to the level where the demand curve intersects this vertical segment of the supply curve. As we shall see in the next section, this plays an important role in the determination of investments in production capacity.

Contrary to fact, the model produces most cross-border trade between the Netherlands and its neighbours at night. This can be explained as follows. In The Netherlands gas-fired production is the marginal technique all the time in the model. During a few hours at night, nuclear power generation is the marginal technique outside The Netherlands and its marginal cost is much lower than the marginal cost of gas in The Netherlands. During the rest of the time, coal-fired generation is the marginal technique outside the Netherlands, and its marginal cost is not much lower than the marginal cost of gas in The Netherlands. Hence in the model gas-fired is never used outside the Netherlands. Though it is an interesting prediction that such a day/night inversion will take place in a fully integrated European electricity market, at present it diminishes the realism of our model.

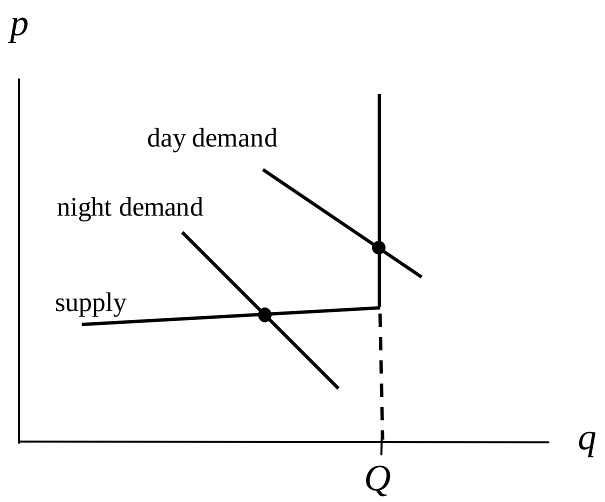
Furthermore, we found that an increase in the demand for electricity in Western Europe (WE) can lower the price of electricity in the Netherlands (NL), while one might expect that a demand increase anywhere in the model will only produce upward price changes. This paradox can be solved as follows: the local demand increase in the exporting region WE lowers the unbalance in the cross-border transport. Hence the auction price for cross-border transport gets lower, and hence also the marginal costs of the export of electricity from WE to NL. This lowers the price of the electricity supplied from WE to NL, and hence lowers the price of electricity in NL.

4.5 Optimal investment in a nutshell

In the previous sections output and prices in the short run were discussed, given the production capacity. Optimal investment in production capacity is discussed in this and following sections. Investment in the model is defined as net investment: zero investment implies constant

[21] See Stoft (2002, pp.68/69) for a discussion of the logic of a marginal cost function with a segment which has an infinite slope. Imagine that the vertical curve in figure 4.2 below is in fact not vertical, but extremely steep – the difference not being visible. Then the derivative exists everywhere (except exactly at the kink in the curve).

Figure 4.2 Demand, supply and capacity[a]



[a] From Boiteux (1960, p.171) and Boiteux (1964, p.77)

production capacity.

For the moment we consider optimal investments for a social welfare maximum, which coincides with perfect competition. Assuming perfect foresight, this optimum requires the following first-order condition, in the form of long run marginal revenues (LRMR) being equal to long run marginal costs (LRMC):

> the price per kWh which is required to keep demand down to capacity, minus marginal running costs per kWh, cumulated over the hours during which capacity is a binding restriction (LRMR), equals the incremental annuitized cost of building an extra kW (LRMC).

In the notation of the previous sections:

$$\sum_{h \in \{q_h = Q\}} p_h - \lambda_h = \frac{\mathrm{d}C(Q)}{\mathrm{d}Q} \tag{4.10}$$

The symbol $C(Q)$ denotes the annuitized cost[22] of building the production capacity Q. This includes costs paid over several decades, up to the present. The derivative $\mathrm{d}C(Q)/\mathrm{d}Q$ is equal to the annuitized current building costs per kW.

The expression $\{q_h = Q\}$ in (4.10) above denotes the set of hours when production capacity is a binding restriction. All marginal costs λ_h are equal during these hours, since all q_h are equal

[22] As in footnote 19: note that C does *not* indicate per unit costs, unlike in De Joode et al. (2004, Appendix 7) and in Lijesen (2004, chapter 4).

during these hours. Also we have $p_h > \lambda_h$ during these hours: this p_h is the price which is required to bring demand at hour h down to capacity. With perfect competition we have $p_h = \lambda_h$ outside these hours. It will be shown below that this result is the special case of the theory applied in our model, when perfect competition is assumed; see equation (4.16) below.

This result shows the dilemma of reserve capacity: investment in production capacity is only profitable if there is not too much of it, since its marginal profit comes from the hours when there is scarcity of production capacity.

A historical note

Optimal investment in electricity production (or in the capital-intensive production of anything non-storable with fluctuating demand) has been already studied in the first half of the previous century. See the French paper Boiteux (1949) and its translations Boiteux (1960) and Boiteux (1964). On page 171 of Boiteux (1960) and page 77 of Boiteux (1964) it is assumed that there are two demand levels: day (high) and night (low), each of them during one half of the time. This is illustrated in figure 4.2. Our equation (4.10) then becomes: $(p - \lambda)/2 = \mathrm{d}C/\mathrm{d}Q$, where p is the price during the day. (The division by 2 is required to express both sides of the equation in the same unit.) The optimal capacity is the value of the daytime demand function given this price $p = \lambda + 2\mathrm{d}C/\mathrm{d}Q$.

The verbal formulation of the first-order condition immediately above our equation (4.10) was adapted from Turvey (1968, pp.91-93). The equation (4.10) itself is the same as equation (10.2.9) in Schweppe et al. (1988, p.242), with the coefficient of the “Quality of Supply” γ_{QS} set to zero.

For the treatment of this subject in the recent literature, see Stoft (2002, pp.126–129) and Hunt (2002, p.410) and the papers described in chapter 1 above.

A numerical example

Equation (4.10) can be illustrated as follows, using the computer model with parameters adapted according to the assumption of perfect competition. We show that with only a few key figures one can compute whether there is (in theory) to much or to little capacity. In section 4.6 below this will be repeated with imperfect competition.

Building costs for gas-fired plants are approximately 900 euro/kW. Let the relevant interest rate be 10% per year. Then marginal investments costs $\mathrm{d}C/\mathrm{d}Q$ are 90 euro/kW per year.

Let the SRMC during peak hours (when capacity is a binding restriction) be $\lambda_h = 3.3$ eurocent/kWh. (This is at the kink in the solid line in figure 4.2 above.) Let these peak hours be 10 hours per day. Let during this time $p_h - \lambda_h$ be equal on average to 75% of λ_h. Then the marginal revenues of investment are 0.75 × 0.033 euro/kWh × 10 hours/day × 365 days/year = 90 euro/kW per year, which is the same as the marginal costs. Hence the production capacity is optimal.

Note that it becomes profitable to invest further if prices increase, variable costs decrease, building costs decrease or the interest rate decreases. In section 4.6 this example is refined with imperfect competition.

4.6 Investment with imperfect competition

In this section equilibrium investment is derived for a system of connected regional markets, with imperfect competition. Recall from section 4.3 above that no optimal combination of production techniques is modelled: any investment is in gas-fired production capacity[23].

The annual profit of firm i in region k equals its operating profit minus capital costs:

$$\begin{aligned}\Pi_{ik} &= \sum_h \pi_{hik} - C(Q_{ik}) \\ &= \sum_h \left(\sum_l p_{hl} q_{hikl} - c_P(q_{hik}, Q_{ik}) - \sum_{l \neq k} c_T(q_{hikl}) \right) - C(Q_{ik})\end{aligned} \tag{4.11}$$

The first-order conditions for a maximum profit are found by differentiating (4.11) with respect to Q_{ik} and equating the result to zero. Note that during the hours h when the production capacity is binding in production region k, we have $q_{hik} = Q_{ik}$ and the profit depends on Q_{ik} not only through the occurrence of Q_{ik} itself in (4.11) but also through the occurrence of q_{hikl} and q_{hik} in (4.11)[24]:

$$\begin{aligned}\frac{\mathrm{d}\Pi_{ik}}{\mathrm{d}Q_{ik}} &= \frac{\partial \Pi_{ik}}{\partial Q_{ik}} + \sum_{h \in \{q_{hik} = Q_{ik}\}} \frac{\partial \Pi_{ik}}{\partial q_{hik}} \\ &= -\sum_h \left(\frac{\partial c_P(q_{hik}, Q_{ik})}{\partial Q_{ik}} \right) - \frac{\mathrm{d}C(Q_{ik})}{\mathrm{d}Q_{ik}} + \sum_{h \in \{q_{hik} = Q_{ik}\}} \frac{\partial \Pi_{ik}}{\partial q_{hik}}\end{aligned} \tag{4.12}$$

[23] Note that this assumption is a formidable reduction of the complication of the model. Without this assumption, even a demand increase in the middle of the night, at an hour at which the capacity is definitely not a binding restriction, has an effect on investment: it changes the optimal technology mix, requiring an investment in a base load technique and an equal desinvestment in a peaker technique. The increase in capital costs is exactly offset by the decrease in variable costs. See Turvey (1968, pp.46-47).

[24] Compare with the total differential: $\mathrm{d}f(x,y) = (\partial f/\partial x)\mathrm{d}x + (\partial f/\partial y)\mathrm{d}y$. Hence $\mathrm{d}f/\mathrm{d}x = \partial f/\partial x + (\partial f/\partial y)(\mathrm{d}y/\mathrm{d}x)$. When $y = x$ then of course $\mathrm{d}y/\mathrm{d}x = 1$.

with

$$\begin{aligned}
\frac{\partial \Pi_{ik}}{\partial q_{hik}} &= \frac{\partial}{\partial q_{hik}}\left(\sum_l p_{hl} q_{hikl} - c_P(q_{hik}, Q_{ik}) - \sum_{l\neq k} c_T(q_{hikl})\right) \\
&= \frac{\partial}{\partial q_{hik}}\left(\sum_l p_{hl} q_{hikl} - \sum_{l\neq k} c_T(q_{hikl})\right) - \lambda_{hik} \\
&\approx \frac{\partial}{\partial q_{hik}} p_{hk} \sum_l q_{hikl} - \lambda_{hik} \\
&= \frac{\partial}{\partial q_{hik}} p_{hk} q_{hik} - \lambda_{hik} \\
&= p_{hk} + G \frac{\mathrm{d}p_{hk}}{\mathrm{d}q_{hk}} q_{hik} - \lambda_{hik} \\
&= p_{hk} - G b^L_{hl} q_{hik} - \lambda_{hik}
\end{aligned} \tag{4.13}$$

The G is the conjectural variations parameter for capacity, similar to g in equation (4.7) above. The approximation ($\approx$) is motivated by the fact that the marginal profit from local supply and from exports cannot be much different, due to the arbitrage possibilities in the model. (There might be a difference at times when the connection between the regions is congested.)

We substitute equation (4.13) into equation (4.12) and proceed on the assumption that the approximation in (4.13) is exact:

$$\begin{aligned}
\frac{\mathrm{d}\Pi_{ik}}{\mathrm{d}Q_{ik}} &= -\sum_h \left(\frac{\partial c_P(q_{hik}, Q_{ik})}{\partial Q_{ik}}\right) - \frac{\mathrm{d}C(Q_{ik})}{\mathrm{d}Q_{ik}} + \sum_{h\in\{q_{hik}=Q_{ik}\}} \left(p_{hk} - G b^L_{hl} q_{hik} - \lambda_{hik}\right) \\
&\approx \sum_{h\in\{q_{hik}=Q_{ik}\}} \left(p_{hk} - G b^L_{hl} q_{hik} - \lambda_{hik}\right) - \frac{\mathrm{d}C(Q_{ik})}{\mathrm{d}Q_{ik}}
\end{aligned} \tag{4.14}$$

The approximation in the second line of equation (4.14) implies ignoring the term with $\partial c_P / \partial Q_{ik}$. This term reflects the older generators being pushed down the merit order, due to the inclusion of the efficient new generator. The SRMC decreases at hours when an old generator is no longer needed[25].

The first-order conditions for a maximum of (4.14) are found by equating the result to zero. Proceeding on the assumption that the approximation in (4.14) is exact, we get:

$$\sum_{h\in\{q_{hik}=Q_{ik}\}} p_{hk} - G b^L_{hl} q_{hik} - \lambda_{hik} = \frac{\mathrm{d}C(Q_{ik})}{\mathrm{d}Q_{ik}} \tag{4.15}$$

[25] In De Joode et al. (2004, Appendix 7) and in Lijesen (2004, chapter 4) this effect is called “variable cost savings”. In the present computer model we have ignored this effect. Of course the marginal costs λ_{hik} themselves are always computed using the correct Q_{ik}, as described in section 4.3.

With perfect competition we have $G = 0$:

$$\sum_{h \in \{q_{hik} = Q_{ik}\}} p_{hk} - \lambda_{hik} = \frac{\mathrm{d}C(Q_{ik})}{\mathrm{d}Q_{ik}} \tag{4.16}$$

and we are back at the nutshell case of section 4.5 above [26] [27].

Assume for a moment that equation (4.16) holds: capacity is optimal with perfect competition. Now introduce oligopoly, with the term with G in equation (4.15). Then the optimal capacity is smaller than the actual capacity: marginal revenues are less then marginal costs. Hence the result of imperfect competition is less production capacity – as with production itself, discussed below equation (4.9).

Finally it might be interesting to note here that as a spin-off from the work on the computer model, the sensitivity of the long run marginal profit $\mathrm{d}\Pi_{ik}/\mathrm{d}Q_{ik}$ for deviations from the equilibrium capacity is defined and computed; see section B.4. In The Netherlands this sensitivity is small because the large markets around us absorb the effect of non-optimal capacity.

Numerical example of investment with imperfect competition

Equation (4.15) can be illustrated as follows, using the computer model.

Coincidentally in the computer model the contribution of the oligopoly term (the term with the G) to equation (4.15) is approximately equal to the capital costs in the right-hand-side for The Netherlands. Hence in this case the price peak $\sum_h p_{hk} - \lambda_{hik}$ is twice as large as in the numerical example in section 4.5. The peak lasts 14 hours per day with $p_h \approx 2\lambda_h$ on average. Hence it lasts $14/10$ times as long and it is $1/0.75$ times as high as the peak in section 4.5, which is indeed together about twice as large.

To illuminate this result further, note that in our model oligopolist firms with zero investment costs would invest only just as much as with perfect competition (the social optimum) and normal capital costs.

The price peak described above is very large. Hence in the model the equilibrium capacity is much smaller than the actual production capacity in the first years of this century in The

[26] Unfortunately in De Joode et al. (2004, Appendix 7) and in Lijesen (2004, chapter 4) the λ term was omitted from the first-order condition for optimal investment, while at the same time the “variable cost savings” term was included, although the latter was not included in the computer model.

[27] Compare with Scheepers et al. (2003, p.31), who define the long run marginal costs as $\mathrm{d}C/\mathrm{d}Q + \sum \lambda_h$ and compare this with $\sum p_h$ (our notation). Hours are operation hours here; not hours when capacity is binding. There is no oligopoly term here.

Netherlands. It takes time to reach the equilibrium capacity, as the growth of demand gradually pushes prices upwards. If ex ante demand is about 28% larger than in 2000, prices are high enough to make equation (4.15) hold true, with the large price peak described above.

Before that point in time is reached, the production capacity is not decreased in the model: we assume that investment cannot be negative.

5 Data and calibration

5.1 Introduction

In this chapter the data used in the model are described: sources, important numerical values, and the method of calibration for some coefficients.

Presently the model contains two regions: The Netherlands on the one hand, and “Other Western Europe” on the other: Germany, Belgium, France, Luxembourg, and Switserland. The model can also switch to only our neighbours Germany and Belgium in the “Other Western Europe” region.

Note that all data values can be found on our website www.cpb.nl.

5.2 Cost data

While using this model, we have used slight variations of the variable cost data, depending among other things on the available data at the time. Typical cost figures for The Netherlands for operation plus maintenance and for fuel (gas-fired, coal-fired, and nuclear) are given in OECD (1998). For the region “Other Western Europe” the costs of gas-fired production are slightly higher than in The Netherlands. Variable costs of renewable and hydro power are not relevant for the computation of the marginal costs, since these techniques are never the marginal technique in the model[28].

Capital costs are required only for gas-fired production; see section 4.3 above. They are expressed in euro/kW per year, or eurocent/kWh[29]. We have used various values, from the 1.2 eurocent/kWh at p.173 in De Joode et al. (2004)[30] to 1 eurocent/kWh. See also the numerical examples in sections 4.5 and 4.6 above.

All costs —except those for hydro— are assumed to decrease with one half percent per year, due to technical progress.

5.3 Production capacity data

We used the production capacity data shown in the table below. The rows of this table are ordered in decreasing merit order: the top rows are used first and the bottom row is used last.

[28] More precisely: these techniques *and* the next technique in the merit order. See the description of our construction of short run marginal costs in section 4.3 above, with a sloping line segment for each technique.

[29] As an aid in the comparison, note that for instance 1 eurocent/kWh equals $1 \times 365 \times 24/100 = 88$ euro/kW per year. This coincides with building costs of 880 euro/kW times an interest rate of 10% per year.

[30] This value is somewhat high for the present purpose, since it gives costs per kWh *produced*.

Obviously in The Netherlands the gas-fired technique is always used, as we noted already in section 4.3 above. These data are computed from the first line in the tables 19 (“Projections of electricity generating capacity by fuel”) in OECD (2003). We defined “Renewables” as the sum of “Combined Renew. & Waste” and “Geothermal Solar Wind”.

We did not use the tables 18 (“Net maximum electricity generating capacity”) in OECD (2003) because with those tables it is difficult (and error prone) to assign production capacity to fuel type, due to multi-fired generation.

Table 5.1 Production capacity, 2000 (GW)

	Netherlands	Other Western Europe	Germany and Belgium	fraction available
Hydro	0	50	10	0.30
Renewables	1	10	8	0.80
Nuclear	0	94	28	0.85
Coal-fired	3	63	51	0.75
Gas-fired	16	51	36	0.75

The GW figures in the table include unavailable generators due to maintenance, repair, etcetera, as indicated by the “fraction available” in the table. This fraction is merely an educated guess. Note that this fraction is not the average utilization rate, which is endogenous in the model.

5.4 Calibrating the demand coefficients

We did not estimate any equation in the model with regression analysis, mainly because there are no timeseries available of commercial electricity markets in the countries included in the model.

However, we did calibrate the demand coefficients of the output model of sections 4.2 through 4.4, using the data of the year 2000. We swapped these coefficients with an equal number of observed (or computed) endogenous variables: the coefficients are temporarily made endogenous and the endogenous variables are temporarily made exogenous. Solving the model in this way gives values for the coefficients. If we then return back to normal simulation (i.e. we undo these temporary changes) and use these values of the coefficients, the endogenous variables automatically get their correct value.

The calibrated coefficients were for each of the two regions l: the $2H$ demand coefficients for the large users (a^L_{hl} and b^L_{hl} in equation (4.3) above), and the 2 demand coefficients for the small users (a^S_l and b^S_l in equation (4.4) above). The number of hours $H = 24$.

These coefficients were calibrated simultaneously against: for each of the two regions $H+1$

assumed demand elasticities (see below), and H large users' demand volumes, and 1 small users' yearly demand volume. Hence $2H+2$ calibrated coefficients against the same number of observations. Note that the ex ante demand pattern obtained in this way fluctuates more than the ex post demand pattern, because prices increase with increasing demand.

Price elasticities are taken from the CPB energy demand model NEMO, described in Koopmans et al. (1999). A value of -0.14 for large users is taken from table 3.3. A value of -0.35 for small users is taken from the row "Households" in table D.2, by adding the bold-face values of Replacement and Good-housekeeping.

For each region, the observed yearly consumption in the calibration year was distributed over the $H = 24$ periods of the day using the observed daily load pattern. It was assumed that the large users together use a fixed GW amount equal to a large fraction of the lowest load (which occurs near 5 o'clock in the morning) plus a variable GW amount equal to a small fraction of the load above the lowest load.

The rest of the load observed in the calibration year is consumed by the small users, whose consumption pattern over the day is computed using the exogenous pattern.

5.5 Interpretation and value of calibrated demand coefficients

Before presenting some results of the calibration, recall that the inverse demand functions in the model are of the following form (see section 4.2 above):

$$p = a - bq \tag{5.1}$$

The coefficient a can be interpreted as the price which reduces demand to zero, although of course the model is not built for such extreme situations. Alternatively this coefficient can be written as the price times a markup which depends on the elasticity:

$$a = p\left(1 + \frac{1}{-\varepsilon}\right) \tag{5.2}$$

Hence coefficient a must be larger than the price p. For the model version with two regions, all calibrated a coefficients were roughly in the range of 35 to 55 eurocent/kWh in 2000, which is indeed much larger than observed prices. The value of a for large users is highest at peak times, since it is proportional with p.

The demand coefficients b vary inversely with the size of the market; see note 11 at page 16. However, the product bq is size independent:

$$bq = a - p = \frac{p}{-\varepsilon} \tag{5.3}$$

Its calibrated values are in the range of approximately 30 to 50 eurocent/kWh, with the same pattern over the day as the value of a, of course.

6 A numerical example

6.1 Introduction

This chapter shows some numerical outcomes of the model, focusing on the value of the conduct parameters. As these parameters play a central role in the model, numerical examples are suitable for illustrative examples as well as sensitivity analysis. The next section assesses the sensitivity of the model to the short term conjectural variations term. The other sections in this chapter illustrate how changes in conjectural variations affect model outcomes.

6.2 Model sensitivity to short term conjectural variation parameters

In chapter 5 we showed how demand parameters are calibrated. The calibration of these parameters involves an assumed value for the short term conjectural variations term g. This raises the question how sensitive model outcomes are to this assumed value. This section assesses the impact of variations in g at a constant demand elasticity. This implies that we vary the value of g throughout the process of calibration and simulation.

We judge the sensitivity of the model by the average price. We average the price over several years to make the result insensitive to fluctuations in any particular year. Although the model contains no business cycles, short cycles may occur due to the small users reacting to previous year's price. Also short cycles may occur due to the solution method, discussed in Appendix B. These cycles are short relative to the chosen time period, i.e. 2005-2020. Table 6.1 presents the results of the sensitivity analysis.

Table 6.1 Sensitivity of average prices, 2005-2020 for calibration with different values of g and G (index, 0.1/0.1=100)

	g				
G	0	0.1	0.2	0.3	0.4
0	77	89	134	469	na
0.1	88	100	139	469	na
0.2	98	111	150	470	na
0.3	108	129	163	474	na
0.4	117	141	182	513	na

It is clear from these results that the influence of parameter g on the outcomes is huge. For larger values of g, prices even become infinite, as was to be expected from our discussion in chapter 3 [31]. The sensitivity to parameter *g* may be worrisome, it also suggests that the chosen parameter is not too far from its actual value. If it would have been, we would not be able to get plausible results for the price-cost margin, as we do now.

6.3 Competition in short run output

Besides the sensitivity analysis performed above, we can also vary the short term conjectural variations term *g* without recalibrating the model. This implies that we assume the value used for calibration to be correct, while investigating the effect of a change in the parameter after calibration. In other words, rather than assessing the impact of variations in *g* at a constant demand elasticity as we did in the previous section, we now assess the impact of variations in *g* with a constant demand curve.

The numerical outcomes in this section are based on demand parameters calibrated at *g*=0.1, with all simulations run at a constant long term conjectural variations term of *G*=0.1. We present three different types of outcomes; the price at noon, the price at 4 AM and the number of hours at which capacity is binding. The first indicator represents peak prices, whereas the second stands for off-peak prices. The number of hours at which capacity is binding is an indication of how tight capacity restrictions are.

Table 6.2 Average prices and hours of binding capacity, 2005-2020 for different values of *g* (index, *g*=0.1=100)

	0.1	0.3	0.5	0.7	0.9
Price at noon	100	113	135	159	181
Price at 4 AM	100	131	159	185	208
Hours of binding capacity	100	56	25	14	10

An increase in *g* impacts both peak and off peak prices in approximately the same magnitude. Note that off-peak prices rise faster than peak-prices, so that the pattern by time of day becomes flatter. Both prices increase fairly strongly, pushing up price-cost margins. Because of the increased price-cost margins, it becomes more interesting to invest in capacity, so producers do not have to suppress profitable demand. Therefore, the number of hours at which capacity is binding decreases.

[31] The model collapses as prices reach infinity, urging us to report 'na' rather than infinity in the table.

6.4 Competition in capacity

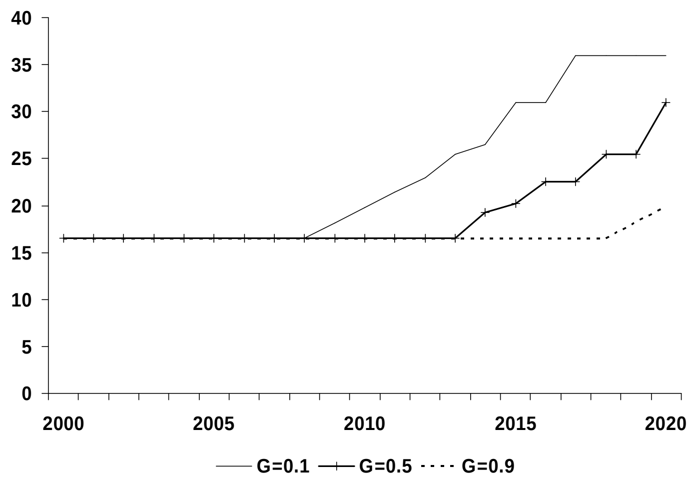
As in the previous section, this section establishes numerical outcomes of variations in the conjectural variations term. This time, the long run term G is varied, while the short term conjectural variations term g is kept at the value of 0.1.

Table 6.3 Average prices and hours of binding capacity, 2005-2020 for different values of G (index, G=0.1=100)

	0.1	0.3	0.5	0.7	0.9
Price at noon	100	129	151	168	177
Price at 4 AM	100	100	101	101	102
Hours of binding capacity	100	141	157	165	174

Table 6.3 illustrates that the impact decreased competition in capacity runs through scarcity. Peak prices and the number of hours at which capacity is binding increase, whereas off-peak prices are hardly affected. This mechanism is even clearer if we look at the timing of investments in new capacity. Assuming demand to grow by 4

Figure 6.1 Domestic capacity over time (GW) for different levels of G



The figure clearly shows that at lower levels of competition, investments will be postponed so that scarcity increases gradually under the influence of growing demand. There seems to be no apparent difference in slopes once the curves start climbing.

6.5 Outcomes for combinations of conjectural variations

In this section, we combine the approach from the two previous sections. We vary both the long run and the short run the conjectural variations terms and look at the effect on prices. Table 6.4 lists the outcomes for the average price.

Table 6.4 Average prices, 2005-2020 for different values of g and G (index, 0.1/0.1=100)

	g				
G	0.1	0.3	0.5	0.7	0.9
0.1	100	124	155	184	210
0.3	129	138	158	184	210
0.5	152	159	170	188	211
0.7	172	176	185	197	214
0.9	182	188	197	207	220

The most interesting finding in table 6.4 is that the influence of G is small for large values of g and vice versa. This implies that the highest of both dominates the outcome, which is quite consistent with theoretical findings (Kreps and Scheinkman, 1983; Davidson and Deneckere, 1986). In general, the influence of g is larger than that of G, which makes sense, as the influence of G is only felt on output for which capacity is binding. Since we have established that g is likely to be larger than G (see chapter 3), the influence of G is even smaller.

Appendix A Local and global profit maximization

Profit is maximized in our model by equating marginal revenues to marginal costs. Hence we might escape a problem discussed in Borenstein et al. (2000), as follows.

They discuss at length the case of two identical markets; each with one producer and one consumer. Producers optimize their output, being Cournot players. Below a certain threshold value of the capacity of the line between the two markets, there is no pure-strategy equilibrium. Above this threshold value the Cournot outcome of a single two-producers market is a unique pure-strategy equilibrium.

However, for each non-zero line capacity the single-market Cournot outcome is a *local* profit maximum for each firm, given the other firm's output. The firms in our model are satisfied with any local profit maximum, since they merely solve the first-order conditions, as noted above. Hence the single-market Cournot outcome is a solution of our model, although more profit may be gained by withholding supply until the connection between the two markets is congested (*into* the market), and then withholding supply further while reaping monopoly profits.

We discovered this with a small computer model of the numerical example in Borenstein et al. (2000, pp. 305/306) with a line capacity for which there is no pure-strategy equilibrium for firms which maximize their profits globally. With firms equating their marginal revenues to marginal costs, this test model produced the single-market Cournot outcome. Indeed a graph of profit as function of supply (with the other firm at the Cournot outcome) shows a double-peaked curve, with the global profit maximum at the left of the Cournot maximum. Computer programs can be obtained from the authors or are available on www.cpb.nl.

Appendix B The computer model

B.1 Introduction

In this section some details about the computer model are discussed. Knowledge of these details is not needed to understand the economics of the model. (However, in section B.4 below an economic concept is introduced: the sensitivity of the marginal profit for deviations from the optimal production capacity.) The actual computer model files will be available on our website www.cpb.nl.

The present version of the model contains two regions and 24 time periods within a year. As discussed following our equation (4.8) above, this amounts to $4HL + HKL = 4 \times 24 \times 2 + 24 \times 2 \times 2 = 288$ equations. In the computer model the short run market also contains equations for marginal costs λ_{hik}, transmission tariffs τ_{hkl}, small users' price p_l^S, etc. Together with the equations for the optimal investment the model has more than 2000 equations.

On the website we have also put some information about the names of the variables, about the software, etc. Those texts need no further discussion here. However, in order to prevent confusion we note one point here: for historical reasons the hour index is denoted as i in the computer files, while in this paper the index i is used for the individual firms and the hour index is h. Since all firms in any particular region are assumed to be equal, no firm index is required in the computer files.

B.2 Restrictions on variables

The short run model contains two restrictions which may or may not be binding, depending on the rest of the model: output is restricted by production capacity, and trade between regions is restricted by transmission capacity. This makes it hard to solve the model, as our software is based on Newton's method, with repeated linearization using numerical derivatives. Numerical derivatives are computed as the ratio of two small perturbations. A change in regime —a restriction becomes binding, or not binding— makes the computed derivatives useless.

Hence the restriction of the production capacity, discussed at the end of section 4.4, was implemented as follows. The prices p_{hl} in equation (4.8) are in fact only provisional. If at hour h the capacity is binding in production region k then the actual price in that region is computed from equation (4.3) for region $l = k$ with the quantity q_{hk}^L replaced by $\sum_i Q_{ik} - q_{hk}^S$.

The maximum transmission capacity is exogenous in the model. This maximum restriction was implemented using the Fisher-Burmeister function; see Fischer (1992).

B.3 Separation of production and investment

Solving the model simultaneously for optimal investment and optimal production is a problem. A positive perturbation in a Q_{ik} (to compute a derivative during the Newton iteration process) creates a change in regime for all q_{hik} which are equal to Q_{ik}. Moreover a negative perturbation of Q_{ik} invalidates the value of these q_{hik}.

Instead, we use last year's marginal profit of investment $\mathrm{d}\Pi_{ik}/\mathrm{d}Q_{ik}$ from equation (4.14) as an indication whether or not investment will increase profit, as follows. Only when this expression was positive in the previous year, will there be investment in the current year. This breaks the simultaneity between production and investment. The amount of investment —if any— is somewhat more than the production capacity in the previous year times the percentage growth rate of demand. Over a period of several years this gives roughly the correct investment on average, with overshooting and undershooting in the individual years. For final results, we run the model with a monthly frequency rather than an annual frequency, in order to mimic the within-year simultaneity between investment and production.

We found that it is not always enough to invest the above mentioned quantity – namely, somewhat more than production capacity in the previous period times the percentage growth rate of demand. "Not enough" meaning here that the marginal profit may be positive and increasing for several adjacent time periods, instead of alternatively positive and negative. This can be explained by the interaction of the two regions: with growing demand in both regions and with differing SRMC curves, there might be a region which must invest not only to satisfy growing local demand but also growing exports.

B.4 The profit sensitivity coefficient σ

The above method of using the marginal profit of investment as an indication whether or not investment is needed, can be improved. Rather than using only the sign of the marginal profit, as in the previous section, one might also use its size, as follows. As we shall see, this did indeed solve the problem described in the last paragraph of the previous section[32].

Let the whole model be compressed into equation (4.15), which we write as

$$\frac{\mathrm{d}\Pi(Q)}{\mathrm{d}Q} = 0 \tag{B.1}$$

It is assumed that all short run equations are solved given any particular value of production capacity Q. In order to simplify the discussion, all subscripts have been omitted here.

[32] This method was not yet used in De Joode et al. (2004) and Lijesen (2004), or in Lijesen and Vollaard (2004).

Let Q^* be the solution of equation (B.1), which is the value of Q for which profit Π is at its maximum. If equation (B.1) does not hold and hence Q is not equal to its optimum Q^* then in the next time period Q is increased through investment. Define the optimal investment ΔQ as:

$$\Delta Q \equiv Q^* - Q \tag{B.2}$$

Following Newton's method, we assume that the derivative $\mathrm{d}\Pi/\mathrm{d}Q$ is linear in a sufficiently large region around $Q = Q^*$. Then ΔQ is proportional with $\mathrm{d}\Pi/\mathrm{d}Q$ in this region:

$$\Delta Q = \frac{\mathrm{d}\Pi}{\mathrm{d}Q}\frac{Q^*}{\sigma} \approx \frac{\mathrm{d}\Pi}{\mathrm{d}Q}\frac{Q}{\sigma} \tag{B.3}$$

where σ is a positive constant, discussed below. The approximation is motivated by the fact that Q will not differ from Q^* by more than the effect of the demand growth in one year (or month). Only when the approximated ΔQ from (B.3) is positive in the previous period, will there be investment in the current period. The quantity of investment —if any— is the approximated ΔQ of the previous period, plus the demand growth rate times the Q of the previous period. This breaks the simultaneity between production and investment, as in the previous section. Equation (B.3) and equation (B.5) below can easily be verified with elementary mathematics[33].

The σ coefficient is size independent in the following sense. When two identical markets are taken together as one market then both profit Π and capacity Q double in size, while σ has the dimension of Π/Q and does not change.

The σ coefficient can be obtained by rewriting the exact part of equation (B.3):

$$\begin{aligned}\frac{\mathrm{d}\Pi}{\mathrm{d}Q} &= \sigma\frac{\Delta Q}{Q^*} \\ &= \sigma - \left(\frac{\sigma}{Q^*}\right)Q\end{aligned} \tag{B.4}$$

The model is solved in a special way, as follows. Demand is kept at the initial level (instead of gradually increasing) and there is no cost-saving technical progress. The capacity Q is gradually decreased exogenously, such that the marginal profit $\mathrm{d}\Pi/\mathrm{d}Q$ —computed from equation (4.14)— becomes positive after some "time periods". In fact in this way the model is solved repeatedly for the initial time period with different values of the production capacity. The scatter

[33] Let the profit near its maximum be a hill-shaped parabola: $\Pi = aQ^2 + bQ + c$, with $a < 0$ and $b > 0$. (These coefficients a, b, and c are used here only for this footnote. They are unrelated to the same symbols elsewhere in the paper.) The derivative of Π is $\mathrm{d}\Pi/\mathrm{d}Q = 2aQ + b$ and hence $\mathrm{d}\Pi/\mathrm{d}Q = 0$ at the value of Q equal to $Q^* = -b/2a$. Equation (B.3) can be written as $\sigma \equiv Q^*(\mathrm{d}\Pi/\mathrm{d}Q)/\Delta Q = Q^*(\mathrm{d}\Pi/\mathrm{d}Q)/(Q^* - Q) = (-b/2a)(2aQ+b)/((-b/2a) - Q)$ $= -b(2aQ+b)/((-b-2aQ) = b$, which is constant. This verifies equation (B.3). At $Q = 0$ we have $\mathrm{d}\Pi/\mathrm{d}Q = 2aQ + b = b = \sigma$, which verifies equation (B.5).

diagram of $\mathrm{d}\Pi/\mathrm{d}Q$ versus Q shows a linear relationship near the point at which $\mathrm{d}\Pi/\mathrm{d}Q$ is zero. The constant term of this linear relationship equals the value σ for the initial time period of the model.

Note that the σ coefficient, which was invented here for the purpose of numerically solving the model, is also an interesting characteristic of the market: using the first line of equation (B.4) it can be described as the sensitivity of the marginal profit for deviations from the optimum production capacity. The dimension of σ is the same as the dimension of the marginal profit, and hence the same as the dimension of the marginal costs of investment. Its unit therefore is either euro/kW per year or eurocent/kWh; see note 29 on page 27.

It can also be shown that if the function $\Pi(Q)$ is quadratic for Q all the way down[34] to $Q = 0$ then

$$\sigma = \left.\frac{\mathrm{d}\Pi}{\mathrm{d}Q}\right|_{Q=0} \tag{B.5}$$

Hence the σ coefficient can also be interpreted as the profit of investment in production capacity if there were no production capacity at all[35].

Values for σ were computed as described above, based on the second line of equation (B.4). This was done for both regions in the model, and also both with and without trading. The resulting values of σ are ranging from 22 to 26 eurocent/kWh, with the exception of The Netherlands when trade is allowed: in this case $\sigma = 8$ eurocent/kWh. This is caused by the fact that a relatively large neighbouring market absorbs the effect of non-optimal local capacity: the price drop (or rise) caused by too much (too little) production capacity increases the export to (import from) the large neighbour. This effect is small if the neighbour is relatively small. Hence it works only for the smallest of two neighbouring markets if they differ very much in size.

With the values of 8 and 24 eurocent/kWh for the two regions respectively, the model can be solved easily, without the problem mentioned in the last paragraph of the previous section.

[34] Note that Π cannot be quadratic for *large* Q. In the scatter diagram of $\mathrm{d}\Pi/\mathrm{d}Q$ versus Q the value of $\mathrm{d}\Pi/\mathrm{d}Q$ becomes a negative constant for Q much larger than Q^*. This constant is equal to minus the investment costs per unit of Q: $\mathrm{d}C/\mathrm{d}Q$. The reason is that with much excess capacity the long run marginal revenue term in equation (4.14) becomes zero since in that case the capacity is never a binding restriction: there are no hours h for which $q_{hik} = Q_{ik}$.

[35] Compare with the interpretation of the a coefficient in the demand function in section 5.5: the price which reduces demand to zero. The model is not built for zero demand or for zero production capacity. However, such interpretations serve to make clear what the dimension of the coefficients is and may help to appreciate their magnitude.

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