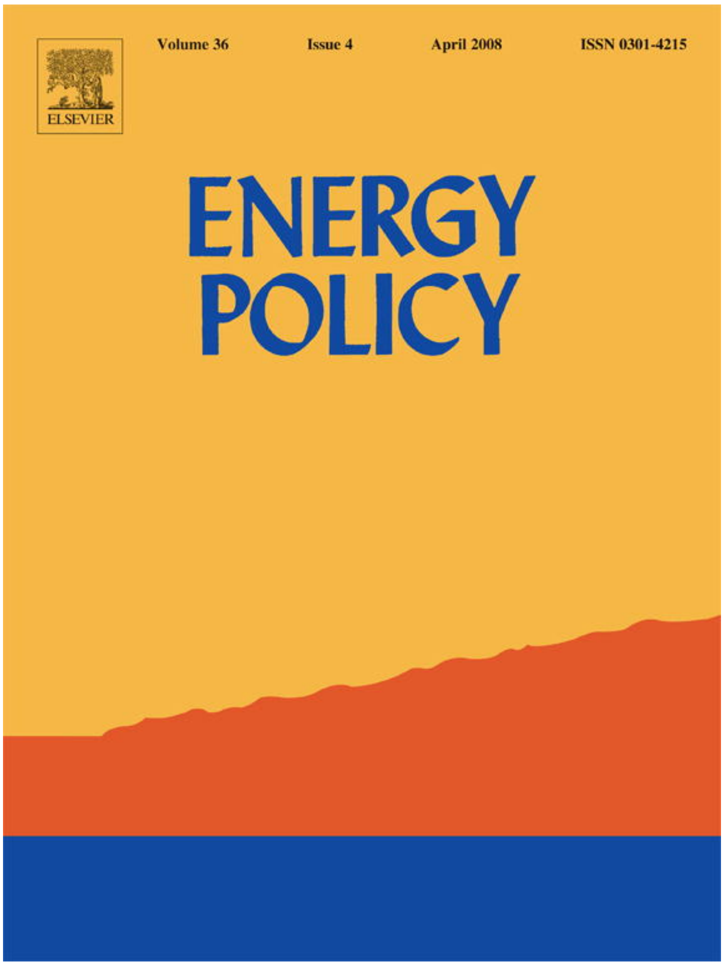
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Market power in the European electricity market—The impacts of dry weather and additional transmission capacity

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Abstract

This paper uses a static computational game theoretic model of a fully opened European electricity market and can take strategic interaction among electricity-producing firms into account. The model is run for a number of scenarios: first, in the baseline under perfect competition, the prices differ due to the presence of various generation technologies and a limited ability to exchange electricity among countries. In addition, when large firms exercise market power, the model runs indicate that prices are the highest in countries where the number of firms is low. Second, dry weather would increase the prices in the hydro-rich Nordic countries followed by the Alpine countries. The price response would be about 20% higher with market power. Third, more transmission capacity would lower the prices in countries with high prices and it also reduces the impact of market power. Hence, more transmission capacity can improve market competitiveness.

Keywords: Electricity market; Market power; Europe

1. Introduction

The European electricity market is currently in the midst of a drastic transformation from monopolistic, national and state-owned producers to a market with competing, private and often multinational firms. By the year 2007, all EU-15 member countries will have liberalised their electricity markets if they live up to their commitments according to EU Directive 96/92/EC, whereas the new member states are underway to liberalise their electricity markets as well, in accordance with the EU Directive 2003/54/EC. This paper also considers two non-EU countries, which are, due to their geographical location, an integral part of the electricity network. In Norway, the electricity market is already fully liberalised (Jamasb, 2001), whereas the Swiss electricity market is not (EE, 2004). The main policy goal of liberalising the electricity market is to achieve more cost-efficient production and lower electricity prices. Although the current state and progress of this process varies widely across Europe, this process will definitely affect the structure of the European electricity market. In the present European electricity market, we can see a whole range of different structures from a near-monopoly in France to highly competitive markets in the Nordic countries. Nevertheless, the policy focus is mainly national, while an EU-wide transmission system operator (TSO) and EU-wide power exchanges are still absent (Glachant and Lévêque, 2006).

Yet, little is known about the consequences of liberalisation. In order to study the liberalised electricity market, a variety of models have been developed by the scientific community. A typical model of a liberalised market can include market coupling, entering of companies and arbitrageurs into particular markets, and the exercise of market power. The models can represent some of the purported benefits: more efficient operation of individual plants (better maintenance, lower outage rates, lower heat

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rates), more efficient dispatch (i.e., choice of plants to operate), lower prices and more efficient investment.[1] Depending on the model design, some of these impacts are endogenously calculated by the models (such as price impacts or more efficient dispatch resulting from market coupling), while others are assumed (e.g., lower heat rates) and the models show the implications of those assumptions for market operations and prices.

There is a large body of literature on electricity market modelling. Here we review the literature concerning (1) oligopolistic competition, (2) the effect of mergers and (3) issues of market design. There are many studies that simulated oligopolistic competition among European power producers in liberalised markets. In some studies there is a comparison of perfect and imperfect competition. Bigano and Proost (2002) conducted a study on four countries, notably France, Germany, Belgium and the Netherlands, linked through electricity trade. The environmental impacts are quantified and they compare strategic action with perfect competition to conclude that phasing out nuclear energy leads to a substantial decrease in social welfare. Newbery (2001, 2002) discusses the potential difficulties in liberalising the EU electricity market. He argues that, due to insufficient regulation, prices are well above marginal costs. Day and Bunn (2001) show with a model based on day-to-day simulations that 'divestiture' does not enforce full competition and prices are well above marginal costs in the England/Wales power pool. Day et al. (2002) and Ventosa et al. (2005) provide a survey of electricity market models. In general, differences in how models treat transmission allocation and pricing can significantly impact their conclusions, even if they all are Cournot in electricity sales (Neuhoff et al., 2005).

Some other studies focus on the effect of mergers. Bower et al. (2001) have simulated the liberalised German electricity market using an agent-based model. They conclude that mergers increase market power leading to higher electricity prices. Amundsen and Bergman (2002) show in a two-country model of Norway and Sweden that cross-border mergers of firms increase the market prices, while the price increase can be partially offset by enlarging the market where the Swedish and Norwegian market are considered as one.

Recently, issues of market design like the effect of market coupling is also studied. In addition to Amundsen and Bergman (2002), Hobbs et al. (2005) study the effects of coupling the Belgian and Dutch market (see also Neuhoff et al. (2005)). Their analysis shows that this clearly benefits the Belgian consumer, while the Dutch consumer's benefit depends upon the producer's behaviour. Bushnell et al. (2004) show how to calibrate a model and compare the outcomes with observed prices using regression models. They show that vertical integration is also important, in addition to market concentration, for explaining market outcomes.

In order to study the complexities of the interacting European electricity markets, we use a static computational game theoretic model. The model captures different market structures depending on a firm's abilities to exercise market power, as well as the extent of access of power suppliers and traders to various geographic markets. This strategic behaviour is based on the theory of Cournot and conjectured supply functions (CSF) on electric power networks. These theories and their relation to other theoretical approaches are discussed by Day et al. (2002). On the one hand, perfect competition, also referred to as Bertrand equilibrium, can be simulated. In a competitive market, firms do not exercise market power and allocate their assets on the basis of marginal cost. On the other hand, strategic competition can be represented, where firms exercise market power to the maximum of their economic interests. The latter is also referred to as the Cournot equilibrium. Several oligopolistic market structures in which firms exercise market power to a more limited extent can be considered as well.[2] Actual markets generally show intermediate levels of competition bounded by the Bertrand and Cournot equilibria, which is also the case for the baseline in this paper. Moreover, computationally more complicated equilibria like the Stackelberg equilibrium generally would also lead to a solution in between Betrand and Cournot (see for instance Lise et al., 2006). However, the calculation of Stackelberg equilibria is a very challenging task, involving the solution of a mathematical program with equilibrium constraints, which is a non-convex problem that potentially has many non-global local equilibria.

The COMPETES (COmprehensive Market Power in Electricity Transmission and Energy Simulator) model version 2.1.2 is used in this paper (Hobbs et al., 2004, 2005). The original model allowed for congestion among six nodes in the Netherlands, two nodes in Belgium, as well as interfaces between those countries, Germany and France. Congestion is generally not observed within the Belgian and Dutch networks and it is therefore justified to simplify the model by considering one node per country. A similar model has been developed by Lise et al. (2006) for eight North-western European countries. The expanded version of the original model covers 20 European countries, which we refer to as 'EU20'. Each of these entries is considered as a single node, except for Denmark, which is divided in east and west, because of the dual link to UCTE and Nordpool. The supply and demand structure of Luxembourg is absorbed into the German market. The

[1] The EU directive 2003/54/EC considers the issue of long-term security of supply, which can be achieved, among others, by stimulating investments in the power sector. A critical analysis of long-run and short-run cost signals in the European electricity market is undertaken by Smeers (2005). He concludes that there is a trade-off among non-discrimination, cost reflectiveness and economic efficiency.

[2] For instance, this is true for models based upon supply function equilibria, where the firms compete more intensely than under Cournot competition. Solving such models is computationally more demanding (Klemperer and Meyer, 1989).

specific theoretical approach and application within COMPETES is described in-depth elsewhere (Hobbs et al., 2004). The approach is contrasted with that of other models in Neuhoff et al. (2005) and a detailed analysis is made of coupling the Dutch and Belgian markets in Hobbs et al. (2005). The COMPETES model may be characterised as a demand-driven model. Given specific levels of demand and short-term marginal cost of supply, allocation of generation capacity, transmission capacity and associated prices are determined for either competitive or Cournot equilibria.

The main research question of this paper is: what are the impacts of (1) dry weather and (2) more transmission capacity on prices in the European electricity market? The scenarios are studied under the assumption of competitive markets or Cournot equilibria. A model with a large geographical coverage best addresses these scenarios, where various important interactions can be included into the analyses. These questions are important, because these contingencies could induce demand side management or new investments in generation capacity and/or transmission capacity. As an illustration of the relevance of such considerations, one may think of the recent and future investments in transmission capacity between Norway and the North-western European mainland. As far as the Norwegian TSO is concerned, these investments are in part justified by the Norwegian need for access to fossil-fired capacity in times of low reservoir levels. Such incentives could be enhanced by changing precipitation patterns across Europe. A dry weather scenario may therefore be driven by global warming and it could give policy guidance as to the needed responses to ensure supply security under those conditions. The scenario also illustrates the vulnerability of the EU20 market to extended drought. In addition, the increased transmission capacity scenario is driven by the current practice that the physically available transmission capacity is often not fully used due to existing regulations, and this scenario would show the effect of making these regulations less stringent so that the existing transmission capacity can be fully used. In addition, there is a tendency of market integration in several regions in the EU, namely the Iberian market, the Italian market, the West European market, the UK–Irish market, the Nordic market, the Baltic market, the East European market and the South-east European market (EU, 2004) and additional transmission capacity will be required to realise this.

The outline of this paper is as follows. Section 2 provides a concise introduction to the model. Section 3 presents results to study the impact of drier weather and increased availability of existing transmission capacity. The final section concludes.

2. Model description

COMPETES covers the European electricity markets of 20 countries, namely Austria (AT), Belgium (BE), Czech Republic (CZ), Denmark-East (DK), Denmark-West (DW), Finland (FI), France (FR), Germany and Luxembourg (DE), Hungary (HN), Italy (IT), Netherlands (NL), Norway (NW), Poland (PL), Portugal (PT), Slovakia (SK), Slovenia (SI), Spain (ES), Sweden (SE), Switzerland (CH), and England and Wales (UK). Net exports to other countries outside this region are added to the loads in ES, FI, HN, IT, NW, PL, SI, SK and UK. Based on the year 2004 values, those exports are estimated to range from −1382 MW in Finland to 538 MW in Hungary.

The representation of the electricity network in the model is aggregated into one node per country, apart from the Danish case where the Eastern and Western networks are distinguished (see Fig. 1). All individual generation units in the 20 countries are assigned to one of these nodes. Virtually all generation companies in the 20 countries are covered by the input data. Also, CHP plants owned by energy suppliers and industrial CHP plants are included.

The user can specify which generation companies are assumed to behave strategically and which companies are assumed to behave competitively (i.e. the price takers). The latter subset of companies is assigned to a single entity per node indicated as the 'competitive fringe'. The model calculates the optimal behaviour of the generators by assuming that they simultaneously try to maximise their profits. Profits are determined as the income of sales (market prices multiplied by total sales) minus costs of transmission (if sale is not at the node of generation) minus the cost of generation. Cost of generation is calculated by using the short-run marginal cost (non-fuel and fuel-variable costs). Start-up costs and fixed operating costs are not taken into account since these costs have less effect on the bidding behaviour of suppliers on the wholesale market in the time horizon considered by the COMPETES model.

The model considers 12 different levels of demand, based on the typical demand during three seasons (winter, summer and autumn/spring) and four time periods (super peak, peak, shoulder and off-peak). The 'super peak' period consists of the 60 hours with the highest sum of the loads for the 20 considered countries in winter and summer and 120 hours in spring/fall; thus, peaks for individual countries are modelled as coincident. The other three periods have equal numbers of hours and represent the rest of the seasonal load duration curve. Altogether, the 12 periods represent all 8760 hours of a year. The consumers are assumed to be price sensitive by using decreasing linear demand curves depending on price. The model includes demand curves representing net wholesale loads on the high-voltage grid. Affine demand curves are calibrated as follows. In each period, an assumed fixed load based upon http://www.ucte.org/, http://www.nordpool.com/, Nordic Competition Authorities (2003) and http://www.bmreports.com, is met under perfect competition (least cost optimisation), which results in a set of market clearing prices. Then, choosing a price elasticity of −0.4 determines the slope of the consumer demand curve at each location. This elasticity is typically representative for decisions spanning a period of a few years, representing countervailing regulatory

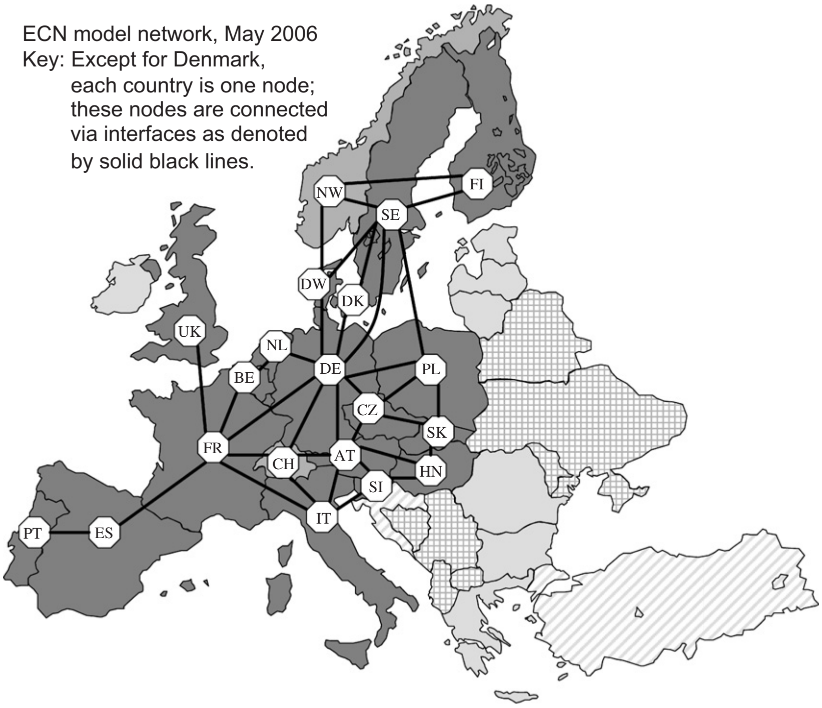


Fig. 1. Physical representation of the electricity network in COMPETES 2.1.2.

threats, vertical integration and long-term contracts (see also Lise et al., 2006). Moreover, a wholesale elasticity of −0.4 translates into a substantially lower retail price elasticity. While the price elasticity of electricity could be argued to be lower when demand is higher in the short run, a uniform elasticity is often assumed in other studies (Hobbs et al., 2005, 2006; Lise et al., 2006). Under a lower elasticity the price increase under Cournot competition would be higher (Hobbs et al., 2005, 2006).

Information on generation units, type of units and the corresponding capacities is primarily based on the WEPP database,[3] updated with publicly available information. Electric availability is based on actual realised levels of generation in 2004 in the EU20 (IEA, 2005). These availabilities will hold for the base load technologies, namely hydro, biomass, waste, other electricity from renewable energy (RES-E) and nuclear, while the availabilities of coal, gas and oil are determined by the model depending on the merit order of the supply curve and demand, with a maximum level of 75%. Electric efficiency per plant is derived from a yearly updated dataset on Dutch, French, German and Belgian generating plants with information on realised production and fuel input using 'annual environmental reports' of the generating companies. From these per plant efficiencies averages are derived per technology, which are assumed to hold for the other 16 countries in the EU20. Moreover, the shares of these technologies can differ from country to country.

The electricity network covering the 20 countries is represented by a direct current (DC) load flow approximation. This approximation is a linear system that accounts only for real power flows (not for reactive power) and is a simplification of the alternating current (AC) power flow model. However, the approximation ensures that Kirchhoff's laws are respected. Using these two laws, the flows within the electricity network can be uniquely identified using the net input of power at each node, i.e., where supply is subtracted from demand.[4] Besides the physical network, path-based constraints are defined using the net transmission capacities (NTC) between the 20 countries. In the current application, these NTCs are set equal to the capacities that are available for the trade on the interconnections between the countries. To determine the NTC value, ETSO (2005) is used, where an average safety margin of 33% is assumed in the baseline, representing an estimate of the emergency (transmission) capacity, which is removed during the scenario of more transmission capacity.[5]

[3]World Electric Power Plants database of 2004 (UDI, 2004).

[4]The DC load flow representation is done through power transmission distribution factors (PTDFs), which are based on a detailed study of the UCTE region by Zhou and Bialek (2005). We are grateful to their generous cooperation in deriving the relevant PTDFs for the 20 nodal network of COMPETES. The results with the PTDFs are nearly the same as the results with path-based constraints and for that reason only the latter results are presented in this paper.

[5]Official interface capacities are usually set very conservatively so that physical flows are feasible under a wide range of possible distributions of generation and loads within each of the countries involved. Our simulations have found, for instance, that the interface auction limits between Germany and the Netherlands involve approximately two-thirds of the flow that can be accommodated by the thermal capacity of the transmission lines between the countries, even accounting for the critical single-line contingencies (see Hobbs et al., 2004).

The strategic behaviour of the generation companies is reflected in the conjectures each company holds regarding the supply response of rival companies. These response functions simulate expectations concerning how rivals will change their electricity sales when prices change; these expectations determine the perceived profitability of capacity withholding and other strategies. COMPETES can also represent different systems of transmission pricing, fixed transmission tariffs, congestion-based pricing of physical transmission and auction pricing of interface capacity between countries. The perfect and strategic competition results presented in this paper reflect two extreme situations, whereas conjectures and Stackelberg equilibria would have led to outcomes in between these two extremes.

In the model, generators or traders will buy network capacity when they want to transport power from one region to another. The total amount of transportation between two nodes can be limited due to the physical transmission constraints (such as thermal or security limits) or due to the limited availability of interconnection capacity between countries due to regulation (see Fig. 1). For the interconnections, we assume no netting for any of the interconnections. In other words, a power flow from, for example, Belgium to the Netherlands will not increase the available interconnection capacity from the Netherlands to Belgium.

Between countries and nodes it can be assumed that arbitrageurs are active. An arbitrageur (or trader) is assumed to maximise its profits by buying electricity at a low-price node and selling it to a high-price node as long as the price difference between these nodes is higher than the cost for transporting the power between these nodes. This is equivalent to a TSO running a 'market splitting' type of auction in which the TSO automatically moves power from low-price locations to high-price locations. Our scenarios do not allow for arbitrage that has not yet been realised, and full arbitrage indeed may not be realised because of many institutional barriers.

The most relevant input data used for the model that will influence the output data are the:

- Fuel prices assumed for each country.
- Availability and efficiency per generation technology. Availability during peak seasons is limited by forced outage rates, while availability during off-peak seasons also accounts for maintenance outages.
- Demand load per season and period within each country.

The fuel prices and the generating unit characteristics are based upon a comparison among various data sources, namely IEA, Eurostat, etc. The generating units are taken from the WEPP database (UDI, 2004) and ownership relations are retrieved from the annual reports of the energy companies. The remaining capacities are assigned to price taking competitive fringes.

In order to explain the results with the model in the next section, it is useful to provide some additional characteristics of the EU20 markets. Thereupon, Fig. 2 presents the generation technology mixes in the 20 countries. Inspection of this figures shows that there is a large variety in generation technologies, where Norway is fully specialised in hydro, Poland in coal, France in nuclear and the Netherlands in gas, among others.

In addition to the technology mix, it is also important to consider the level of market concentration, because this is an important determining factor in market power. Table 1 shows the market shares of the firms that can exercise market power. In each market, the competitive fringe is represented by a single entity, aggregating the price-taking companies, and indicated with the prefix "Comp". Note

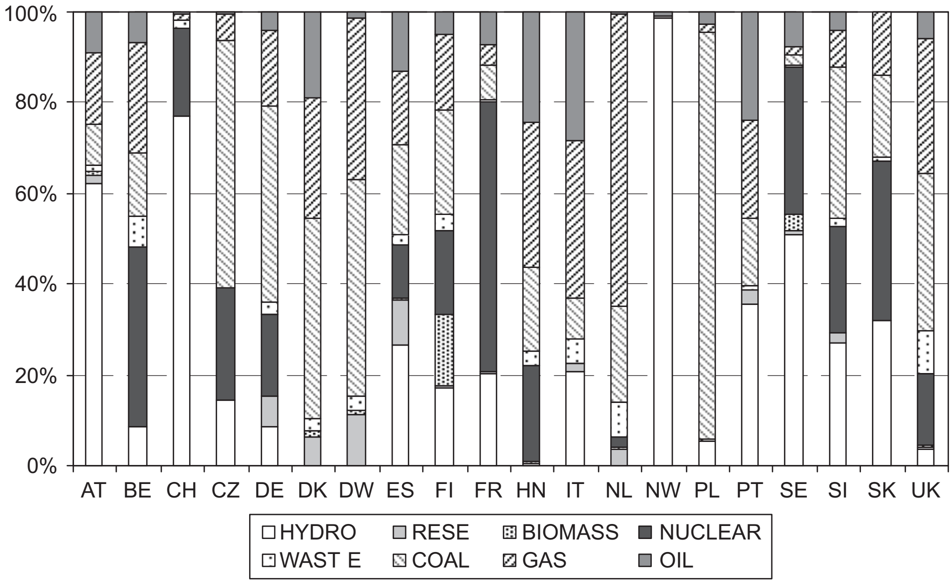


Fig. 2. Technology mix per country in the EU20 by installed capacity.

Table 1
Generation capacity (MW) and market shares of the major companies in the EU20

		Total	Market share (%)
AT	Comp_AT	9872	58
AT	VERBUND-Austrian hydro power	7027	42
BE	Electrabel SA	13,100	85
BE	Comp_BE	2285	15
CH	Comp_CH	17,205	100
CZ	CEZ AS	12,580	84
CZ	Comp_CZ	2472	16
DE	Comp_DE	36,362	30
DE	RWE Power	27,160	23
DE	E.ON Energie AG	27,132	23
DE	Vattenfall AB	16,891	14
DE	Energie Baden-Wurttemberg EnBW	10,480	9
DE	Electricite de France	1005	1
DE	Essent Energie Productie BV	697	1
DE	Electrabel SA	422	0
DK	ENERGI E2 A/S	3844	95
DK	Comp_DK	220	5
DW	ELSAM A/S	4137	93
DW	Comp_DW	334	7
ES	Comp_ES	21,002	36
ES	ENDESA generacion	16,688	29
ES	Iberdrola SA	14,550	25
ES	Union Electrica Fenosa SA	3891	7
ES	Energie Baden-Wurttemberg EnBW	835	1
ES	RWE Power	423	1
ES	ENEL SPA	141	0
ES	CIA PORTUGESA PRODUCAO ELEC	106	0
FI	Comp_FI	11,206	72
FI	Fortum Power & Heat	4098	26
FI	E.ON Energie AG	165	1
FR	Electricite de France	92,453	83
FR	Comp_FR	13,899	13
FR	Electrabel SA	4820	4
HN	Comp_HN	5344	61
HN	RWE Power	655	7
HN	Electricite de France	401	5
HN	ENERGIE Baden-Wurttemberg EnBW	208	2
IT	ENEL SPA	43,519	51
IT	Comp_IT	25,705	30
IT	Edison SPA	8534	10
IT	ENDESA generacion	5979	7
IT	Electrabel SA	1210	1
NL	Electrabel SA	4911	26
NL	Essent Energie Productie BV	4614	25
NL	Nuon NV	4020	22
NL	Comp_NL	3236	17
NL	E.ON Energie AG	1883	10
NW	Comp_NW	19,154	67
NW	Statkraft SF	9453	33
PL	Comp_PL	29,233	86
PL	Electricite de France	2501	7
PL	Electrabel SA	1800	5
PL	Vattenfall AB	611	2
PT	CIA PORTUGESA PRODUCAO ELEC	7454	59
PT	Comp_PT	4254	33
PT	RWE Power	1005	8
SE	Vattenfall AB	13,003	42
SE	Comp_SE	12,568	41
SE	Fortum Power & Heat	3168	10
SE	E.ON ENERGIE AG	2200	7
SI	Comp_SI	2833	100
SK	Slovenske elektrarne AS (SE)	3462	47
SK	Electricite de France	3347	45
SK	Comp_SK	557	8
UK	Comp_UK	35,014	50
UK	British Energy PLC	13,286	19
UK	E.ON Energie AG	8405	12
UK	RWE Power	8093	12

that power markets in Poland, Slovenia and Switzerland are relatively competitive, as a result of the presence of large fringes in those countries, representing 86% of generation capacity in Poland and 100% of generation capacity in Slovenia and Switzerland (see Table 1).

To solve the model, we have assumed that the competitive fringes can only sell in the market where they are located. Large firms can sell in the market where they are located and all countries to which they are directly connected. For instance, EdF can sell in almost all countries, except Norway, Finland and Portugal. Table 2 shows the assumptions concerning market access. Alternative assumptions could be made, such as all firms having access to all countries. In theory, the EU Directive allows for such freedom of trade, but due to not yet fully liberalised markets and regulatory rules, access may be limited. For instance, Spain would have to give access to its grid in order for French producers to have access to the Portuguese market.

Further active cross-border ownership is assumed so that a single firm owning generation plants in various countries optimises over its full portfolio. This assumption may somewhat overestimate the ability of firms to use market power, because due to a number of organisational and technical reasons, firms may, in practice, optimise their behaviour only within single markets.

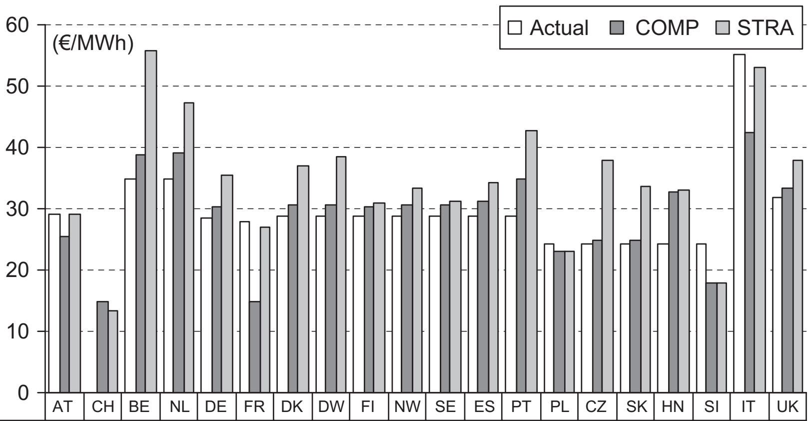
3. Results

3.1. Baseline

We consider two cases based on the ability of firms to exercise market power, namely perfect competition (COMP) and strategic competition (STRA). In the COMP case, demand is fixed in order to find the corresponding equilibrium prices, while a price demand elasticity of -0.4 is assumed in the STRA case. The results are presented in terms of yearly average prices in Fig. 3, whereas Table 3 presents hourly prices.

Table 2
Countries where the large firms can sell electricity

	AT	BE	CH	CZ	DE	DK	DW	ES	FI	FR	HN	IT	NL	NW	PL	PT	SE	SI	SK	UK
British Energy PLC										✓										✓
CEZ as	✓			✓	✓										✓				✓	
CIA PORTUGESA PRODUCAO ELEC								✓		✓						✓				
E.ON Energie AG	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓
Edison SpA	✓		✓							✓		✓						✓		
Electrabel SA	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓		✓		✓	✓	✓	✓
Electricite de France	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓		✓		✓	✓	✓	✓
Elsam A/S					✓	✓	✓		✓					✓			✓			
ENDESA Generacion	✓		✓					✓		✓		✓				✓		✓		
ENEL SPA	✓		✓					✓		✓		✓				✓		✓		
ENERGI E2 A/S					✓	✓	✓										✓			
Energie Baden-Wurttemberg EnBW	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓		✓	✓	✓	✓	✓	✓
Essent Energie Productie BV	✓	✓	✓	✓	✓	✓	✓			✓	✓	✓	✓		✓		✓	✓		
Fortum Power & Heat					✓	✓	✓		✓					✓	✓		✓			
Iberdrola SA								✓		✓						✓				
Nuon NV	✓	✓	✓	✓	✓	✓	✓			✓			✓		✓		✓			
RWE Power	✓		✓	✓	✓	✓	✓	✓		✓	✓	✓	✓		✓	✓	✓	✓	✓	✓
Slovenske elektrarne AS (SE)				✓							✓				✓				✓	
Statkraft SF							✓		✓					✓			✓			
Union Electrica Fenosa SA		✓						✓		✓			✓			✓				
Vattenfall AB	✓		✓	✓	✓	✓	✓		✓	✓			✓	✓	✓		✓		✓	
VERBUND-Austrian hydro power	✓		✓	✓	✓						✓	✓						✓		



	AT	CH	BE	NL	DE	FR	DK	DW	FI	NW	SE	ES	PT	PL	CZ	SK	HN	SI	IT	UK
Actual	29.0		34.7	34.7	28.5	28.0	28.8	28.8	28.8	28.8	28.8	28.7	28.7	24.1	24.1	24.1	24.1	24.1	55.2	31.9
COMP	25.4	14.7	38.7	39.1	30.4	15.0	30.7	30.6	30.4	30.5	30.5	31.1	34.8	23.1	24.9	24.9	32.7	18.0	42.5	33.5
STRA	29.0	13.2	55.8	47.4	35.3	26.9	36.8	38.4	31.0	33.3	31.1	34.2	42.9	23.1	38.0	33.7	33.2	17.9	53.0	37.7

Fig. 3. Actual and simulated average prices under perfect and strategic competition (€/MWh).

Inspection of Fig. 3 yields the fact that in the COMP case the prices differ considerably, indicating the presence of congestion, because two prices can only be different in two bordering countries if the transmission line between countries is congested. The lowest prices are found in Switzerland and France, countries where nuclear installations turn out to be the marginal unit in a number of representative hours, setting the prices in these markets (see Table 3, the marginal cost of nuclear is about €10/MWh). Further, the highest price levels are encountered in the Italian market. In addition, one may observe that prices are (nearly) the same within five country pairs, namely Czech Republic–Slovakia, Denmark-East–Denmark-West (which is surprising, given that this an important interface between UCTE and Nordpool and that there is no physical connection), Norway–Sweden (and Finland), the Netherlands–Belgium and Spain–Portugal. This shows that the transmission capacity between these country pairs is often not binding.

Table 3 can also be used to discuss the calibration result of the model. In general, the prices are the highest under super peak hours, followed by peak hours, shoulder hours and the lowest under off-peak hours, because the demand decreases by going from super peak to off-peak hours.

Table 3
Hourly prices under six scenarios

	AT	BE	CH	CZ	DE	DK	DW	ES	FI	FR	HN	IT	NL	NW	PL	PT	SE	SI	SK	UK
COMP baseline																				
(w, super peak)	35.4	41.9	32.5	28.5	32.5	42.8	42.8	41.0	34.2	32.7	35.4	41.0	41.9	62.5	23.1	41.0	62.5	23.1	28.5	39.3
(w, peak)	32.5	41.9	32.5	28.5	32.5	42.8	42.8	41.0	34.2	32.5	35.4	41.0	41.9	42.8	23.1	41.0	42.8	23.1	28.5	39.3
(w, shoulder)	32.5	41.9	29.3	28.5	32.5	32.5	32.5	29.0	32.5	29.3	35.4	41.0	41.9	32.5	23.1	36.3	32.5	10.3	28.5	31.3
(w, off peak)	23.1	34.8	9.4	23.1	25.9	25.9	26.4	23.5	30.5	9.9	28.5	41.0	34.8	25.9	23.1	28.9	25.9	10.3	23.1	31.3
(m, super peak)	35.4	41.9	29.3	23.1	32.5	42.8	32.5	41.0	34.2	29.3	35.4	41.0	41.9	56.2	23.1	41.0	56.2	23.1	23.1	39.3
(m, peak)	32.5	41.9	17.8	28.5	32.5	32.5	32.5	36.3	32.5	17.8	35.4	41.0	41.9	32.5	23.1	36.3	32.5	23.1	28.5	39.3
(m, shoulder)	28.5	41.9	9.4	23.1	32.5	30.5	30.5	29.0	30.5	9.9	35.4	41.0	41.9	30.5	23.1	36.3	30.5	23.1	23.1	31.3
(m, off peak)	10.3	34.7	9.4	23.1	25.9	25.9	25.9	23.5	30.5	9.9	28.5	41.0	34.7	25.9	23.1	28.9	25.9	10.3	23.1	31.3
(s, super peak)	32.5	28.0	9.4	23.1	32.5	30.5	30.5	41.0	30.5	9.9	35.4	58.4	41.9	30.5	23.1	41.0	30.5	28.5	23.1	39.3
(s, peak)	32.5	38.4	9.9	23.1	32.5	30.5	30.5	41.0	30.5	9.9	35.4	58.4	41.9	30.5	23.1	41.0	30.5	23.1	23.1	31.3
(s, shoulder)	28.5	41.9	9.4	23.1	32.5	30.5	30.5	29.0	30.5	9.9	35.4	41.0	41.9	30.5	23.1	36.3	30.5	23.1	23.1	31.3
(s, off peak)	9.9	28.0	9.4	23.1	25.9	25.9	25.9	29.0	18.8	9.9	23.1	41.0	28.0	18.8	23.1	29.0	18.8	10.3	23.1	31.3
STRA baseline																				
(w, super peak)	48.9	67.6	26.1	45.2	37.4	60.0	50.4	43.4	36.0	51.6	37.5	57.9	54.6	68.8	23.1	53.9	66.9	23.1	37.3	39.3
(w, peak)	43.4	65.8	26.4	43.7	37.4	51.6	45.5	41.0	34.2	50.5	35.4	55.9	52.3	49.6	23.1	50.1	48.3	23.1	38.8	39.3
(w, shoulder)	35.3	64.3	21.9	41.7	37.4	39.4	42.0	33.4	34.2	45.3	35.4	52.3	50.1	35.7	23.1	44.4	34.4	10.3	38.2	39.2
(w, off peak)	23.1	47.6	9.4	35.8	32.5	31.0	33.4	27.5	30.5	20.4	30.7	42.2	41.9	25.3	23.1	36.3	25.6	10.3	32.7	34.8
(m, super peak)	47.5	66.4	24.0	39.2	37.4	51.8	42.8	42.5	34.2	46.3	36.4	57.8	53.7	65.3	23.1	52.6	56.8	23.1	33.4	39.3
(m, peak)	38.9	64.6	15.3	41.6	37.4	40.7	42.8	41.0	34.2	31.0	35.4	57.2	51.4	40.1	23.1	45.7	35.7	23.1	37.5	39.3
(m, shoulder)	29.3	58.4	9.4	38.0	36.8	36.0	39.0	32.6	30.5	20.4	35.4	52.4	48.6	31.4	23.1	43.4	30.1	23.0	33.0	39.0
(m, off peak)	13.5	46.2	9.4	34.7	32.1	30.2	33.3	27.7	30.5	19.9	28.6	45.9	41.9	26.2	23.1	36.3	23.8	10.3	31.3	35.4
(s, super peak)	40.2	43.2	9.4	37.5	37.4	39.6	41.4	41.9	30.5	20.2	35.4	71.6	52.6	31.8	23.1	53.3	30.3	26.9	30.8	39.3
(s, peak)	36.2	52.0	10.6	37.9	37.4	37.3	40.3	41.5	30.5	20.2	35.4	71.3	51.9	33.3	23.1	50.4	30.5	23.1	32.9	39.2
(s, shoulder)	28.5	57.5	9.4	36.5	35.8	36.1	39.0	32.7	30.5	20.1	35.4	52.2	47.5	32.9	23.1	42.6	29.9	23.1	30.2	38.3
(s, off peak)	12.1	42.4	9.4	30.9	30.0	28.2	28.4	29.0	20.6	19.0	26.2	47.9	39.2	19.1	23.1	36.3	18.1	10.3	28.5	34.1
COMP dry weather																				
(w, super peak)	45.4	41.9	32.5	28.5	32.5	42.8	42.8	41.0	34.2	34.1	35.4	41.0	41.9	88.7	23.1	44.0	87.7	23.1	28.5	39.3
(w, peak)	36.6	41.9	32.5	28.5	32.5	42.8	42.8	41.0	34.2	32.7	35.4	41.0	41.9	63.0	23.1	41.0	59.7	23.1	28.5	39.3
(w, shoulder)	32.5	41.9	32.3	28.5	32.5	42.8	32.5	29.3	34.2	29.3	35.4	41.0	41.9	45.3	23.1	36.3	42.8	11.5	28.5	31.3
(w, off peak)	25.9	34.7	10.4	23.1	25.9	29.5	29.2	25.1	30.5	10.4	28.5	41.0	34.7	31.3	23.1	28.9	30.5	10.3	23.1	31.3
(m, super peak)	41.9	41.9	32.3	23.1	32.5	42.8	32.5	41.0	34.2	31.1	35.4	41.3	41.9	80.6	23.1	41.0	71.4	23.1	23.1	39.3
(m, peak)	35.4	41.9	21.4	28.5	32.5	41.8	32.5	38.1	34.2	19.8	35.4	41.0	41.9	48.7	23.1	38.1	41.8	23.1	28.5	39.3
(m, shoulder)	32.5	41.9	9.9	23.1	32.5	32.5	32.5	29.0	32.5	9.9	35.4	41.0	41.9	37.7	23.1	36.3	32.5	23.1	23.1	31.3
(m, off peak)	18.2	34.8	9.9	23.1	25.9	29.2	29.2	25.9	30.5	9.9	28.5	41.0	34.8	31.7	23.1	28.9	29.2	10.3	23.1	31.3
(s, super peak)	35.4	28.0	9.9	23.1	32.5	32.5	32.5	41.0	32.0	9.9	35.4	58.4	41.9	34.5	23.1	41.0	32.5	28.5	23.1	39.3
(s, peak)	32.5	38.4	11.3	23.1	32.5	32.5	32.5	41.0	31.6	9.9	35.4	58.4	41.9	39.6	23.1	41.0	32.5	23.1	23.1	31.3
(s, shoulder)	32.5	41.9	9.9	23.1	32.5	32.5	32.5	29.0	31.4	9.9	35.4	41.0	41.9	40.3	23.1	36.3	32.5	23.1	23.1	31.3
(s, off peak)	15.0	28.0	9.4	23.1	25.9	25.9	25.9	29.0	23.7	9.9	23.1	41.0	28.0	25.9	23.1	31.8	23.7	10.3	23.1	31.3

STRA dry weather																				
(w, super peak)	52.4	67.6	28.9	45.2	37.4	68.4	58.7	44.2	39.3	51.9	38.1	58.4	54.6	99.3	23.1	54.0	82.5	23.1	37.6	39.3
(w, peak)	48.7	65.8	29.7	43.8	37.4	59.7	52.0	41.5	38.7	50.8	35.5	58.4	52.3	69.8	23.1	50.2	58.8	23.1	39.2	39.3
(w, shoulder)	41.0	64.3	28.0	41.8	37.4	44.6	42.8	35.7	34.2	45.6	35.4	53.6	50.1	51.3	23.1	44.5	43.4	11.5	38.8	39.2
(w, off peak)	27.5	47.7	11.2	36.0	32.5	35.5	37.8	29.0	31.9	20.5	32.0	43.1	41.9	37.2	23.1	36.3	31.1	10.3	33.7	34.8
(m, super peak)	52.3	66.4	27.8	39.2	37.4	60.7	43.0	42.9	38.5	46.6	37.1	58.4	53.7	87.8	23.1	52.7	69.8	23.1	33.9	39.3
(m, peak)	45.1	64.7	21.4	41.6	37.4	44.5	42.8	41.0	34.2	31.2	35.4	58.4	51.4	52.8	23.1	45.7	43.2	23.1	37.9	39.3
(m, shoulder)	35.8	58.5	11.5	38.2	37.3	41.4	42.4	33.2	33.7	20.5	35.4	54.1	49.0	44.1	23.1	43.4	36.2	23.1	33.9	39.1
(m, off peak)	18.2	46.2	10.5	34.9	32.3	35.3	37.7	29.0	31.0	20.1	29.1	46.4	41.9	37.0	23.1	36.3	30.3	10.3	32.3	35.4
(s, super peak)	45.9	43.2	11.2	37.8	37.4	40.7	42.8	43.1	32.3	20.3	35.4	73.7	52.6	42.0	23.1	53.4	34.3	28.5	31.0	39.3
(s, peak)	42.0	52.1	12.4	38.0	37.4	41.1	42.8	42.6	32.8	20.3	35.4	72.2	51.9	44.4	23.1	50.5	34.9	23.1	33.6	39.2
(s, shoulder)	33.6	57.6	11.5	36.6	36.3	39.9	40.8	33.9	32.1	20.2	35.4	53.9	47.8	44.2	23.1	42.7	34.1	23.1	31.4	38.3
(s, off peak)	15.1	42.6	9.4	31.3	30.4	29.6	32.6	29.9	22.8	19.4	26.2	49.1	39.4	27.0	23.1	36.3	21.2	10.3	28.6	34.1
COMP more transmission capacity																				
(w, super peak)	32.7	41.9	32.7	28.6	32.7	51.7	42.8	41.0	34.2	32.7	35.4	41.0	41.9	56.2	23.1	41.0	56.2	23.1	28.6	39.3
(w, peak)	32.5	41.9	32.5	29.6	32.5	41.7	41.7	41.0	34.2	32.5	35.4	41.0	41.9	41.7	23.1	41.0	41.7	23.1	29.6	39.3
(w, shoulder)	32.5	41.9	29.3	28.5	32.5	32.5	32.5	29.0	32.5	29.3	35.4	41.0	41.9	32.5	23.1	36.3	32.5	10.3	28.5	31.3
(w, off peak)	23.1	29.2	9.4	23.1	25.9	25.9	25.9	23.5	28.1	10.8	27.9	41.0	29.2	25.9	23.1	28.9	25.9	10.3	23.1	31.3
(m, super peak)	32.5	41.9	31.3	24.7	32.5	42.8	32.7	41.0	34.2	31.4	35.4	41.0	41.9	49.7	23.1	41.0	49.7	23.1	24.7	39.3
(m, peak)	32.5	41.9	20.1	28.5	32.5	32.5	32.5	35.2	32.5	20.1	35.4	41.0	41.9	32.5	23.1	36.3	32.5	23.1	28.5	39.3
(m, shoulder)	28.5	41.9	9.4	24.7	32.5	30.5	30.5	29.0	30.5	9.9	35.4	41.0	41.9	30.5	23.1	36.3	30.5	23.1	24.7	31.3
(m, off peak)	12.0	28.0	9.4	23.1	25.9	25.9	25.9	23.5	26.9	9.9	23.1	41.0	28.0	25.9	23.1	28.9	25.9	10.3	23.1	31.3
(s, super peak)	32.5	31.0	9.4	23.1	32.5	30.5	30.5	41.0	30.5	9.9	35.4	58.4	41.9	30.5	23.1	41.0	30.5	28.5	23.1	39.3
(s, peak)	32.5	38.5	9.9	23.6	32.5	30.5	30.5	41.0	30.5	9.9	35.4	58.4	41.9	30.5	23.1	41.0	30.5	23.1	23.6	31.3
(s, shoulder)	28.3	41.9	9.4	23.1	32.5	30.5	30.5	29.0	30.5	9.9	35.4	41.0	41.9	30.5	23.1	36.3	30.5	23.1	23.1	31.3
(s, off peak)	10.3	26.4	9.4	23.1	25.9	19.3	25.9	28.9	19.3	9.9	23.1	41.0	26.4	19.3	23.1	28.9	19.3	10.3	23.1	31.3
STRA more transmission capacity																				
(w, super peak)	42.8	62.9	23.1	41.2	37.6	58.4	50.3	42.7	36.5	48.9	36.3	56.1	52.4	64.3	23.1	53.9	62.3	23.1	38.9	39.3
(w, peak)	37.5	59.6	24.5	40.5	37.4	50.4	42.8	41.0	34.2	47.5	35.4	53.9	50.3	45.6	23.1	50.1	45.7	23.1	38.9	39.3
(w, shoulder)	32.7	58.1	21.0	40.4	37.4	39.9	39.2	32.9	34.2	42.6	35.4	51.5	47.8	32.9	23.1	44.4	34.9	10.3	38.6	39.3
(w, off peak)	24.4	44.6	9.4	34.0	32.5	31.3	30.7	26.9	30.5	20.4	28.8	41.0	41.9	24.2	23.1	36.3	26.4	10.3	33.0	34.3
(m, super peak)	41.1	59.6	21.6	36.8	37.4	52.0	42.8	41.8	35.1	43.5	35.4	56.4	50.5	57.4	23.1	52.6	54.7	23.1	34.9	39.3
(m, peak)	36.1	57.0	15.3	40.5	37.4	40.7	41.3	41.0	34.2	29.5	35.4	55.0	49.5	35.9	23.1	45.7	35.9	23.1	38.6	39.3
(m, shoulder)	29.2	50.4	9.4	35.3	35.7	35.9	35.8	32.0	30.5	20.4	35.4	51.6	45.6	29.7	23.1	43.4	30.5	23.1	33.5	39.1
(m, off peak)	15.0	44.6	9.4	32.8	31.4	30.9	30.5	26.9	30.5	20.0	28.5	44.4	41.9	24.5	23.1	36.3	25.3	10.3	31.4	34.9
(s, super peak)	36.8	42.0	9.4	35.3	37.4	37.6	37.2	41.0	30.5	20.1	35.4	68.7	48.9	30.5	23.1	53.3	30.5	28.4	32.7	39.3
(s, peak)	32.9	46.7	10.6	34.9	37.3	37.1	36.9	41.0	30.5	20.3	35.4	69.7	49.3	31.3	23.1	50.4	30.5	23.1	33.6	39.2
(s, shoulder)	28.5	49.2	9.4	33.4	34.8	34.9	35.7	32.1	30.5	20.0	35.4	51.3	44.5	30.9	23.1	42.6	30.5	23.1	31.7	38.8
(s, off peak)	13.4	37.6	9.4	29.5	29.0	28.0	26.4	29.0	19.7	19.0	23.8	47.0	35.6	18.9	23.1	36.3	18.7	10.3	28.5	33.4

The calibration of the model follows these general principles quite well, except for five instances among the 240 prices. For instance, the super peak price in Czech Republic–Slovakia is lower than the peak price in the spring/autumn season, the super peak is lower than the peak, which is lower than the shoulder price in Belgium in the summer, and the super peak price in Switzerland is somewhat lower than the peak price in the summer. A reason for this deviation is that the demand in the model is ordered to the sum of total demand in the EU20, and this would not necessarily lead to a strict order of demand levels within each country. As a second principle, the winter prices are generally the highest, followed by spring/autumn prices, while the summer prices are the lowest. However, summer prices are higher than the prices in other seasons in Solvenia, Italy, Spain and Portugal, because the summer demand in South Europe is particularly high due to demand for cooling during summer.

In addition to the COMP result, Fig. 3 also shows the STRA result. A consideration of the difference between the STRA and COMP prices gives insight into the incidence of market power. The highest price is found in Belgium, where also the highest price difference is found between COMP and STRA. The differences in prices are due to (1) the ability to exercise market power (determined by the market shares of large firms in the market) and (2) accessibility of the market. The second argument plays a role for instance in Italy, where the market concentration is lower than in France and Belgium, but due to low accessibility still experiences a relatively high price increase. The Danish market on the other hand is quite accessible from various countries and this reduces the ability to exercise market power in the Danish market of the near monopoly players Elsam and Energi E2. Interestingly, the prices in Switzerland decrease in case of strategic competition in relation to a perfectly competitive evaluation. This is the result of the exercise of market power in neighbouring countries, so that the relevant foreign firms are facing an increase in spare capacity. The additional spare capacity is available to serve the Swiss market. The resulting increase of supply to the Swiss market leads to a price decrease in Switzerland due to demand response. In particular, this price decrease is a consequence of increasing imports from France during super peak and peak hours in winter, spring and autumn (see Table 3).

Fig. 3 also contains the actual average prices in 2004, which we collected from Eurostat.[6] A comparison of the actual prices to the baseline results indicates that in the majority of the power markets considered, the competitive prices are in line with the actual average prices. This comparison indicates that the prices in the EU20 in 2004 were close to competitive prices and that there were no major issues of market power exercise. In three countries, the actual prices are close to the Cournot prices, namely in Austria, France and Italy. The French price is currently regulated and largely follows the German price; the model results show that in a free market the French prices could be substantially lower. The higher prices in Austria and Italy may indicate that these markets were under the influence of market power in 2004. Eurostat did not report any price for Switzerland, whereas the Hungarian price in the model is higher than actual and the Slovenian price in the model is lower than actual. A reason for this is the assumption in the model where the competitive fringe can only sell locally, which was needed to solve the model for the EU20. There is only a competitive fringe of Slovenia, which would like to sell to Hungary where there are higher prices, but they cannot. Note, however, that the Hungarian and Slovenian markets are relatively small and that this border effect does not have any impact on the rest of the EU20.

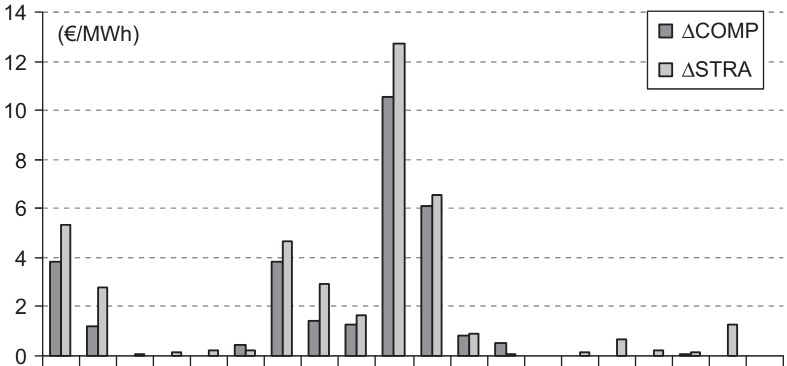
3.2. Consequences of dry weather

In addition to the two baseline runs with the model, it is also possible to use the model to further address policy challenges. An interesting question is to study the effect of lower rainfall, leading to a reduced availability of hydro and possibly higher prices. This analysis points out what the effects would be during a dry year. In order to curb these effects, various policy measures could be undertaken in order to reduce the need for generation in critical regions during such events like demand-side management measures, new investments in back-up generation capacity or addition of transmission capacity (see also Section 3.3). Fig. 4 presents the result of the dry weather simulation, where the availability of conventional hydro is reduced by 30% and price elastic demand responses are possible. Less elastic demand would have led to more extreme price effects.

Inspection of Fig. 4 shows that the resilience of the EU20 markets differs considerably from country to country. It is not surprising to find that the price response is the highest in Norway, a country with 99% of hydro generation capacity. The second largest response is found in Sweden, a country with 51% of hydro generation capacity and which is fully congested with the Norwegian market. The scarcity of Norway also has an impact on Finland and Denmark, but to a lower extent. Also, a relatively large response is found in Austria, a country with 62% of hydro generation capacity and in Switzerland, a country with 77% of hydro generation capacity. Austria and Switzerland have substantial import capacity, but these are already congested in the baseline.

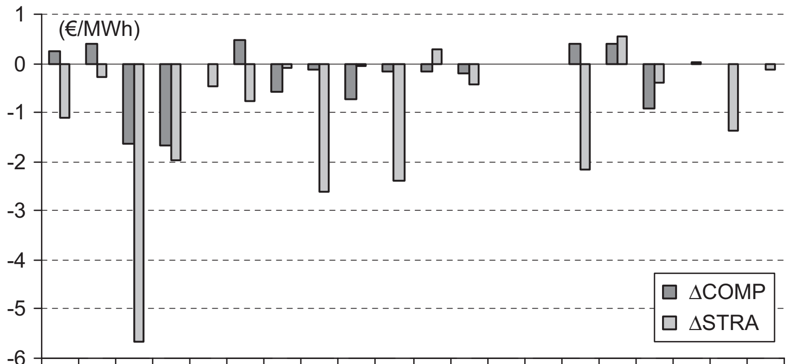
The price increase of dry weather and market power is largely in the same direction as under perfect competition, only the effect is more pronounced. Moreover, a number of other countries start to experience some price rises once market power plays a role, e.g., in Slovenia and Italy. Overall, the price response would be about 20% higher with market power.

[6]Available at www.ec.europa.eu/eurostat



	AT	CH	BE	NL	DE	FR	DK	DW	FI	NW	SE	ES	PT	PL	CZ	SK	HN	SI	IT	UK
ΔCOMP	3.87	1.24	0.00	0.00	0.00	0.42	3.83	1.42	1.30	10.5	6.06	0.82	0.54	0.00	0.00	0.00	0.00	0.09	0.00	0.00
ΔSTRA	5.33	2.80	0.09	0.12	0.19	0.21	4.70	2.96	1.65	12.7	6.57	0.94	0.06	0.00	0.12	0.70	0.22	0.12	1.26	0.00

Fig. 4. Average price increase under perfect and strategic competition caused by dry weather (€/MWh).



	AT	CH	BE	NL	DE	FR	DK	DW	FI	NW	SE	ES	PT	PL	CZ	SK	HN	SI	IT	UK
ΔCOMP	0.24	0.41	-1.6	-1.6	0.00	0.48	-0.5	-0.1	-0.7	-0.1	-0.1	-0.2	-0.0	0.00	0.41	0.41	-0.9	0.00	0.00	0.00
ΔSTRA	-1.1	-0.2	-5.6	-1.9	-0.4	-0.7	-0.0	-2.6	-0.0	-2.3	0.28	-0.4	0.00	0.00	-2.1	0.56	-0.3	0.03	-1.3	-0.1

Fig. 5. Average price decrease under perfect and strategic competition caused by 50% more transmission capacity (€/MWh).

3.3. Consequences of more transmission capacity

Concerning our representation of transmission management, we are assuming efficient allocation of capacity (coordination of spot and transmission markets through market splitting, where netting of electricity flows is not allowed). Our results represent an idealised situation, but it has not yet been realised, and indeed may not be realised because of many institutional barriers. Another policy question is related to the current policy of low investments in the intra-country interconnections.

Fig. 5 shows the price effect of widening the interconnection capacity to the original transmission capacity levels reported by the European transmission system operators (ETSO). This effect largely leads to lower prices, while in some markets the prices increase to a limited extent, because local producers export more power to higher price markets elsewhere rather than to sell it locally. Inspection of the figure shows that in particular the Dutch and Belgian markets benefit from measures that increase the available interconnection capacity for trading purposes, as these markets currently show both limited interconnection capacity and moderate to high levels of concentration. Moreover, the current investment plans to expand the transmission capacity among the Netherlands, Germany, Norway and UK. This is because of the already high prices in these countries. Significant price decreases under perfect competition are also found in Hungary (surrounded by low-price markets), Finland (export during super peak) and Eastern Denmark (going down to the Nordpool price).

An increase of interconnection capacity will lead to more trade flows under the STRA scenario. This is illustrated by the price decrease not only in Belgium but also in Czech Republic, Western Denmark, Italy and Norway. It is also remarkable that the prices in Italy under perfect competition, which were the highest, do not change. Though interconnection capacity to the Italian market is limited, international trade with the Italian market is further limited by the fact that competitive fringes in these markets largely determine the Slovenian and Swiss markets. They would like to export to Italy, but they are not allowed to do so, because the fringe only supplies the local market.

The trading opportunities of the competitive fringes have been limited to the market of presence only, so that the majority of the generators in the Slovenian and Swiss markets are not allowed to export electricity to the Italian market by assumption. As this effectively forms the main limitation to trade, the substantial increase of the interconnection capacity does not relieve the constraints on Italian imports. The substantial increase of import capacity from France remains insufficient to alter the marginal technology in Italy in the COMP case.

4. Conclusions

This paper has used the static COMPETES model. The COMPETES model is run for a number of scenarios to derive additional insights for covering the geographical EU20 area. The model simulations indicate the following. First, under perfect competition in the liberalised European electricity market, the prices differ due to the presence of various generation technologies and a limited ability to exchange electricity among countries. Second, in the case where all large firms exercise market power, the model runs indicate that the biggest price responses are found in countries where the number of firms is low. The differences in prices are due to (1) the ability to exercise market power (determined by the market shares of large firms in the market) and (2) accessibility of the market.

In addition, we studied the effect of dry weather, leading to a reduced availability of hydro and possibly higher prices. The simulations indicate that the resilience of the EU20 markets differs considerably from country to country. The highest price response is in Norway and Sweden. To a lesser extent, Finland and Denmark also experience price increases due to their dependence on the former markets. The second highest price response is found in Switzerland and Austria. The price increase of dry weather and market power is largely in the same direction as under perfect competition, only the effect is more pronounced. The price response would be about 20% higher with market power.

Finally, we studied the effect of increased interconnection capacity. This largely leads to lower prices, while in some markets the prices increase to a limited extent. This outcome is due to the improved tradability, where the countries with relatively high prices see prices decrease and, to a lesser extent, countries with relatively low prices see prices increase. Consumers in countries with relatively high prices benefit from more interconnection capacity. More transmission capacity would not only lower the prices in countries with high prices; it also reduces the impact of market power. Hence, more transmission capacity can improve market competitiveness.

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