Political Shocks and Efficient Investment in Electricity Markets

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***Abstract*--This paper presents a fundamental electricity market model capturing many essential features of investments in electricity markets – fuel price developments, investment and generation costs, demand and dynamic effects such as start-up costs and (pump) storage dispatch. The partial equilibrium model minimizes the total costs of the electricity system ensuring demand coverage. The model optimizes both long-run investment as well as short-run dispatch decisions. From the optimal solution, the optimal future generation technology mix and dispatch can be derived. Furthermore, using the concept of shadow prices in mathematical programming, we calculate electricity price predictions. The model is applied to analyze the effect of recent political shocks in German nuclear energy policy on the electricity market and the power plant portfolio. The effect is quantified using the example of a specific combined cycle gas turbine project. We find a significant impact on the future net revenues.**

***Index Terms*—Electricity Market, Investment Modeling, Linear Programming, Electricity Generation, Dispatch**

I. Introduction

FOR long-term investment decisions, predictability of the political environment is an essential aspect. When an earthquake severely damaged the Fukushima nuclear power plant in Japan in March 2011, many debates arose whether or not nuclear energy should be used as a mean to generate electricity. All over the world, countries reviewed their perspective on nuclear energy. One of the leading countries in this process was Germany. Here, the nuclear debate was not a new phenomenon.

In the year 2000 a consensus between the social democratic German government and the main electricity providers had limited the life time of nuclear power plants to an average of 32 years. This implied that the last nuclear power plants would shut down in the early 2020s. After many discussions and a change in government, this decision was revised by prolonging the life time of nuclear power plants by 8 (older plants) or 14 years (newer plants) respectively, only to change this decision again in the first half of 2011. After the serious accident in Fukushima a strong public movement forced the government to again reduce the running times of nuclear power plants. This time, several power plants were shut down immediately and all remaining plants will successively be shut down by 2022 the latest.

These changes in the German nuclear power policy greatly affected the entire energy market. Nuclear power is a power generation technology with very low variable generation costs and does hardly emit CO_2. Due to the low variable generation costs, nuclear plants have a high utilization (often above 7,000 hours per year). When less nuclear generation capacity is available to cover the base load, more expensive technologies need to take over their task. Furthermore, the replacement technologies are usually gas or hard coal fired and hence emit more CO_2 – which in turn leads to higher CO_2 prices.

For investors in power generation technologies, the fundamental implications of such political decisions can be crucial for the profitability of investments. In this paper, we therefore investigate how the mentioned changes affected the profitability of investment decisions. In section II. related literature will be discussed. In section III. the problem settings will be presented. Section IV. describes the model in more detail and in section V. the results will be evaluated. The last section VI. provides suggestions for further research and concludes.

II. Literature Review

Some aspects of electricity markets are unique due to the nature of the product. Electricity is a product that needs to be consumed immediately, as the potential for economical storage of electricity is limited. Additionally, the market exhibits economies of scale. Those result from indivisibilities[1] or other non-convexities such as start-up and shut-down costs (Edwards and Starr, 1987) and need to be accounted for.

There exist three main approaches to model electricity markets – a fundamental approach which looks at the competitive market equilibrium, a second approach modeling strategic behavior mostly via aggregated supply functions and an agent-based approach which determines market interaction from the point of view of the different agents in the market.

Fundamental approaches look at the market from a more general perspective and try to find market equilibria without taking into account strategic behavior of the different market participants. Most of the fundamental approaches use mathematical programming to determine an optimal production plan. As long as the constraints are linear and the variables used are continuous, the model is a linear program (LP) and less computationally demanding. To model indivisibilities properly however, some of the variables might need to be integer variables. Then the corresponding model is

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[1] Indivisibilities for instance include unit commitment issues or minimum output requirements.

a mixed integer program (MIP), which is considerably more computationally demanding.

A useful property of mathematical programs is the fact that the variables of the corresponding dual program can be interpreted as shadow prices. For more detailed information on the formation of shadow prices refer to Aucamp and Steinberg (1982) in combination with Akgül (1984). For an LP the interpretation of dual variables is quite straightforward. For MIPs this can be more challenging. Gomory and Baumol (1960) have done an early attempt at the interpretation of the resulting dual variables as shadow prices. However, their dual variables still had a few peculiar features and did not always match with the economic value of the resources. In a more recent approach, O'Neill et al. (2005) suggest to subsequently solve the MIP and then the corresponding LP including additional constraints for fixing the values of the integer variables. This will result in reasonable dual variables without the peculiar properties of the ones by Gomory and Baumol (1960). However, not only the original resources have shadow prices, but also the additional integral activities. Hence, in a real market, they would need prices to achieve market clearing. This is not how the German power market works where hourly electricity prices are negotiated for energy (in EUR/MWh). While there is an additional market for balancing power, there is no market for e.g. start-ups or other integer variables.

Furthermore, although modeling the electricity market by a MIP is in some respect more accurate, LPs avoid the high computation time of MIPs. Hence, they can be more accurate in other respects e.g. modeling timely resolution more realistically in addition to avoiding the already mentioned difficulties with the interpretation of shadow prices. Nonetheless, even when an LP model is used, the conversion of shadow prices into electricity prices is not always straightforward. There might exist nonzero shadow prices for more than one constraint. Bohn et al. (1984) give an example on how to price both the energy production and its transportation within a network.

Several authors have already addressed the topic of modelling the electricity market. Müsgens (2006) presented a multi-regional LP model with 7 European countries, several generation technologies, power exchange between countries, (pump) storage plants, startup processes and minimum load requirements. Stigler and Todem (2005) presented a MIP model of the Austrian electricity market focusing on nodal pricing and technical transmission issues. Their model is run stepwise, first solving a MIP to decide on the integer unit commitment decision and then solving a non-linear program (NLP) considering transmission line losses. They also reason why the market clearing price corresponds to the marginal costs of the system. Leuthold et al. (2010) present an extension of the model by Stigler and Todem which includes several other European countries.

In contrast to the models mentioned above the presented electricity market model considers a much larger time horizon of 4.380 periods per year running over several reference years. This allows to include investment decisions in the model and to give a more accurate representation of the varying structure of different aspects of the electricity market during the course of a year.

III. Problem Discussion

A. General Aspects

1) Political Development

In the last decade, there have been several radical changes in the German nuclear energy policy. The first fundamental decision regarding nuclear energy was taken in 2000. The social democratic government decided to phase out of nuclear electricity generation. The lifetime of the existing nuclear power plants was limited to an average of 32 years. Each power plant received a specified amount of energy it was allowed to produce as of the 1st of January 2000 before its shutdown. Those energy amounts summed up to 2.620 TWh. The agreement was called the *atomic consensus* (Bundesregierung, 2000) and legally ratified in 2002.

In the year 2010, the Christian democratic German government revised this decision by prolonging the running times of nuclear power plants by 8 or 14 years depending on the age of the power plant. Nuclear power plants built before 1980 received 8 additional years, whereas all younger plants received 14 additional years of running time. This was called the *energy concept*. (Bundesregierung, 2010)

However, shortly after the decision to extend life-times was made, the severe accident in Fukushima took place in March 2011. As a consequence, public opinion forced the government to re-reduce the running times of nuclear power plants. Several power plants were shut down immediately and the remaining plants will successively be shut down until 2022. This has been known as *nuclear phase-out 2022* (Bundesregierung, 2011).[2]

2) German Electricity Market

For the evaluation of investment decisions, the electricity price is a central aspect. In Germany, the reference electricity price is determined at the EPEX 'day ahead' electricity market. This market is organized as an auction. Each day at noon such an auction takes place for the electricity generation of each hour of the following day.

Buyers submit bids indicating how much electricity they are willing to buy at which price. Sellers submit bids how much electricity they are willing to sell at which price. A specialty of the German market is the selling of the output of renewable energies. Due to German regulation, this electricity is sold price-independently.

Bids wanting to buy are combined to an aggregated demand curve. Bids wanting to sell are combined to an aggregated supply curve. The resulting intersection of supply and demand gives the single market clearing price that will be paid for the actual provision of electricity.

The market is designed in such a way that minimum cost production of electricity is promoted. Generation technologies which can produce at lower variable costs will be able to place a bid with a lower unit price. Those technologies will then be awarded before other technologies are considered.

3) Model Approach

To model such an electricity market, we suggest a fundamental model that is capable of predicting the general development of the power plant portfolio as well as the corresponding electricity prices both in the near future and in

[2] An English version of the current Atomic Energy Act was published by the German Federal Office of Radiation Protection (2011).

the long run. The model represents the European electricity market by covering several interconnected regions (Germany and the most important neighboring countries). In each of these regions, demand for electricity needs to be covered at any point in time. In the model, different electricity generation technologies are considered – thermal power plants, (pump) storage power plants and (exogenously) renewable energies. Furthermore, power exchange between neighboring countries is endogenously modeled.

The model assumes perfect competition. While there is a huge debate on market power in electricity markets in the short term (see e.g. Borenstein et al. 2002 who analyze market power in California's electricity market), the problem seems less pronounced in the long run. In the time horizon analyzed in this paper, new power plants can be built. Hence, if market power in the short run would increase prices above total costs of new capacity, new entrants would enter the market. While it would have to be analyzed whether and which barriers to entry exist, this is not in the focus of this paper.

From economic theory it is known that in a perfectly competitive market, the equilibrium will be at the cost minimum and zero profits will be achieved in the long run. Furthermore, each electricity provider will bid its variable costs.

The electricity market model calculates electricity prices fulfilling analogous principles. From those prices and a given cost structure of a certain technology, future earning possibilities of that technology can be determined.

B. Data

The electricity market model requires a lot of input data – information on the existing power plant portfolio, demand predictions, prices for the different fuel types and CO_2 certificates, information on renewable energies and their electricity generation as well as information about interconnector capacities connecting Germany and the surrounding European countries.

The information about the existing power plants of the different technologies[3] (and those currently being built) in the different countries is based on own research. A power plant database has been accumulated not only with data about the capacity of power plants but also with information about minimum load requirements, net efficiencies, load gradients, possible technical lifetimes, variable and fixed production costs as well as start-up and shut-down costs.

The annual demand predictions have been taken from the eurolectric Power Statistics (2010) for all countries besides Germany. For Germany, we used a study by EEFA and r2b energy consulting (2010). The demand profile within each year is based on historical data from ENTSO-E[4], where data for two hours is averaged arithmetically to form one period.

Primary energy carrier[5] prices are based on the IEA World Energy Outlook 2010 and other publications by the IEA, NEA and OECD (2010).

Due to the feed-in subsidy, renewable energies in Germany do not react to scarcity signals. Hence, they are considered exogenous in our model. The generation from these sources (including wind power, photovoltaic power, geothermal power, biomass and bio waste power, hydroelectric power, landfill and sewage gases as well as other electricity generation technologies[6]) is subtracted from demand to get a 'residual demand' – which then is covered by the endogenous technologies. For all countries besides Germany the future electricity generation from renewable energies has been taken from the national action plans published by the European Commission (2009) up to the year 2020. From 2020 onward the development was carried forward. The structure by which the wind generation is distributed within a year is based on historical data from the year 2008. The data was corrected for year-specific peculiar characteristics. The corresponding structure for photovoltaic power is taken from the published historical data of the Joint Research Center of the European Commission[7]. The two-hourly generation profiles for the other renewable energies were also based on historical data from various sources. The renewable energy information for Germany is based on own calculations. In the underlying model, data on generation potentials, costs as well as subsidies are considered.

One last important data aspect relates to the interconnector capacities. The net transfer capacities (NTC) between all modeled countries were taken from the ENTSO-E database[8]. The same holds for net exchange amounts to neighboring countries which are not incorporated in the model. The future development of both exchange capacities and amounts is based on a study by consentec and r2b-energy consulting (2010).

C. Scenarios

The three political situations under consideration will be represented by three scenarios:

- SC 1 - atomic consensus
- SC 2 - energy concept
- SC 3 - nuclear phase-out 2022

In reality the general economic frameworks of the three scenarios differ in many aspects. However, as we want to focus on nuclear power, only the capacities of nuclear power plants and the corresponding CO_2 prices are modified between the three scenarios. Comparing the development of installed nuclear net generating capacities in the three scenarios, which are depicted in Fig. 1, one can see a strong similarity between the first and the third scenario. Hence, in contrast to the public debate in Germany, the nuclear phase-out from 2011 was in fact just taking back the extension of life-times in the energy concept in 2010.

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[3] These include nuclear power, lignite, coal, combined cyclic gas turbines, open cyclic gas turbines and (pump) storage plants.

[4] Refer to htpps://www.entsoe.eu.

[5] Depending on the primary energy carrier prices, aspects such as waste management for nuclear power are included.

[6] Other power generation technologies include CHP generation, industrial gases, waste incineration, solar heat power and wave and tide power plants.

[7] Refer to the Photovoltaic Geographical Information System (PVGIS) at http://re.jrc.ec.europa.eu/pvgis/index.htm.

[8] Refer to htpps://www.entsoe.eu.

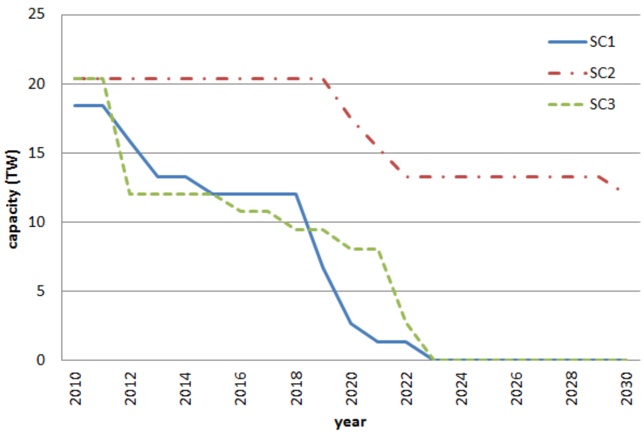

Fig. 1. Nuclear power plant capacity in the three different scenarios.

The CO_2 prices vary between the scenarios. The more electricity nuclear power plants produce, the less CO_2 is emitted in the German electricity industry. As the total European goal for emissions in the emission trading system is fix, other sectors can emit more and the prices will be lower. The development of the CO_2 prices can be seen in Fig. 2.

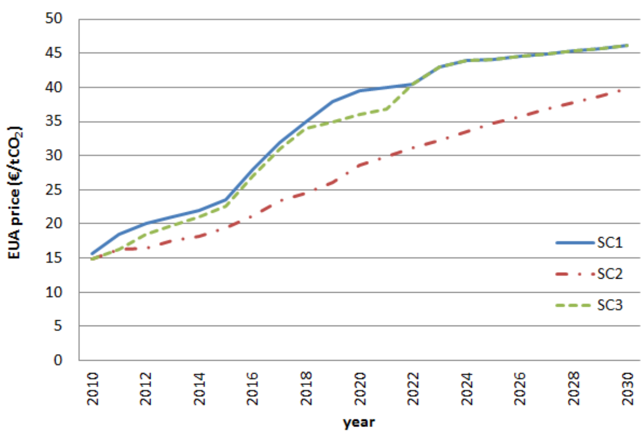

Fig. 2. Prices of CO_2 emission certificates in the three different scenarios.

IV. Model

We apply a fundamental market model, looking at the electricity markets in Germany and other European countries. The total costs of electricity generation are minimized using an LP while covering the demand and meeting all other technical constraints.

The model makes a distinction between different electricity generation technologies. For thermal electricity generation technologies the model can determine both its optimal production and maintenance schedule as well as additional capacity commissioning or capacity decommissioning. For hydro power generation technologies such as storage and pump storage plants, the model optimizes pumping and electricity generation. The capacities of the (pump) storage plants have been determined exogenously.

To represent not only the short run electricity generation, but also the long run development of the power plant portfolio, the model optimizes several reference years indexed by y simultaneously. Each reference year is thought of as a representation of the upcoming years up to the next reference year. The reference years are linked via a capacity constraint (i.e. capacities in one reference year are determined by capacities from the last reference year plus commissionings minus decommissionings). The electricity dispatch itself is optimized for each model year individually in two-hour periods indexed by p.

Ten European countries[9] are modeled as ten separate regions. For the different regions the index r is used. Within each region, thermal power plants are grouped and aggregated into vintage classes characterized by their primary energy carrier, its use and the degree of innovation[10]. The different technology groups can be identified by the index t. The model distinguishes up to one nuclear vintage class, 6 lignite vintage classes, 7 coal vintage classes, 6 combined cycle gas turbine (CCGT) vintage classes and 3 open cycle gas turbine (OCGT) vintage classes in each region.

Considering all relevant dimensions the model optimizes up to 23 technologies t in 10 regions r over 4.380 periods p for several reference years y (in the setting of our empirical calculation we have 10 reference years which gives a total of 43.800 different time steps). This constitutes a rather high resolution compared to other electricity market models.

A. Key Elements of the Linear Program

In the following section, the key elements of the model including the main variables, the objective function and central constraints will be presented. An overview of the relevant variables and parameters is given in Table II

.[11] All variables considered in the model are positive and continuous.

As mentioned before, the main objective of the linear program is the minimization of total costs Z. The objective function considers direct costs of thermal power plant generation only. The costs for hydro pump storage plants are implicitly covered, because the energy consume for pumping has to be produced by the thermal power plants.

To account for the efficiency loss under operation in part load, the total generated amount G_{TOTAL} is split into two parts - one part that is produced under full load operation G_{FULL} and one part that is produced under minimum load operation G_{MIN}. As the variable production costs for generation under minimum load z_{min}^{var} are higher than the ones under full load production z_{full}^{var}, the model will always try to produce as much electricity as possible under full load operation while still meeting the minimum load requirement for the remaining amount.

This leaves the objective function with the variable generation costs (split up into full load and minimum load production), the startup and shutdown costs, the fixed capacity costs as well as the relevant share of the investment costs[12] for all newly

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[9] The countries that were considered are Germany, Switzerland, Austria, France, Belgium, the Netherlands, the UK, Italy, Poland and the Czech Republic.

[10] Among other things, the degree of innovation takes into account the age of a power plant and its net efficiency.

[11] Variables - in contrast to parameters - are capitalized.

[12] The relevant share of the investment costs s_{invest}^{cost} is determined by assuming annuity payments for the share of the power plant's lifetime that will take place within the time horizon of the optimization.

commissioned capacities. All terms are summed over the relevant dimensions, discounted and will be minimized.

$$
\begin{aligned}
\min Z = \; & \sum_{y} f_y^d(y) * \\
& (\text{years}(y) * \\
& [\sum_{p,t} \text{hours} * f_p^d(p) * z_{full}^{var}(y,p,t) * G_{FULL}(y,p,t) \\
& + \sum_{p,t} \text{hours} * f_p^d(p) * z_{min}^{var}(y,p,t) * G_{MIN}(y,p,t) \\
& + \sum_{p,t} f_p^d(p) * z_{up}(y,p,t) * C_{UP}(y,p,t) \\
& + \sum_{p,t} f_p^d(p) * z_{down}(y,p,t) * C_{DOWN}(y,p,t) \\
& + \sum_{t} z_{fixed}(y,t) * C_{INST}(y,t)] \\
& + \sum_{t} s_{invest}^{cost}(y,t) * z_{invest}(y,t) * C_{ADD}(y,t))
\end{aligned} \tag{1}
$$

The installed capacity C_{INST} of each vintage class t can be modified on a reference year basis. The following balance constraint holds.

$$
\begin{aligned}
C_{INST}(y,t) = \; & C_{INST}(y-1,t) + C_{ADD}(y,t) \\
& - C_{SUB}(y,t)
\end{aligned} \tag{2}
$$

In the first year of the optimization, no commissioning is possible because power plants need a significant amount of time to be built.[13] Decommissioning of existing capacities has been predefined (based on both the power plants' age and additional information on shut-down dates). The model is, however, allowed to reschedule the decommissioning to an earlier year than anticipated if this saves costs. Commissioning projects that have been planned or are already in construction are also predefined. On top of this, the model can endogenously commission additional capacities. For some primary energy carriers, the total amount of capacity over all vintage classes that use this energy carrier is limited due to availability restrictions.

Each year a share of the installed capacity s_{OH} needs to undergo overhaul. This share of the total installed capacity is predefined, but the model can decide for itself how much of the overhaul is done in the different months of the year indexed by m.[14]

$$
\sum_m \left[C_{OH}(y,m,t) * \frac{\sum_p m_{mp}(m,p)}{\sum_p 1} \right] \geq C_{INST}(y,t) * s_{OH}(y,t) \tag{3}
$$

Subtracting the capacity in overhaul C_{OH} (and a certain percentage of the remaining capacity for unplanned unavailabilities) from the installed capacity yields the available capacity C_{AVAIL} in each period.

As in reality, not all available capacity has to be ready-to-operate. The model can decide how much of the capacity is ready-to-operate C_{RTO} by starting new capacity up C_{UP} or shutting running capacity down C_{DOWN} in a certain period.

$$
\begin{aligned}
C_{RTO}(y,p,t) = \; & C_{RTO}(y,p-1,t) + C_{UP}(y,p,t) \\
& - C_{DOWN}(y,p,t)
\end{aligned} \tag{4}
$$

The capacity ready-to-operate cannot exceed the available capacity.

The capacity ready-to-operate limits the electricity generation of each technology. One might wonder why there should ever be more capacity ready-to-operate than is actually necessary for the electricity generation. This can be beneficial if a shutdown and startup process would be more expensive than keeping spare capacity ready-to-operate for a restricted period of time.

One essential constraint of the model is the demand constraint that ensures that the electricity supply can cover the demand.

$$
\begin{aligned}
d_{res}(y,p,r) \; & + U(y,p,r) \\
& + \sum_{r'} \left(1 + \frac{s_{loss}^{grid}}{2}\right) * E(y,p,r,r') \\
& + e_{net\_exp}(y,p,r) \\
& + G_{SURPLUS}(y,p,r) \\
= \; & \\
\sum_t m_{rt}(r,t) * G_{TOTAL}(y,p,t) \; & + G_{STOR}(y,p,r) \\
& + \sum_{r'} \left(1 - \frac{s_{loss}^{grid}}{2}\right) * E(y,p,r',r)
\end{aligned} \tag{5}
$$

The sum of all forms of demand - including the residual demand d_{res}, the energy consumed by pumps U as well as energy exports E and e_{net_exp} - needs to equal the sum of all forms of supply - including the generation by thermal power plants G_{TOTAL}, the generation by turbines G_{STOR} and all imports E. On the demand side of the equation, the term $G_{SURPLUS}$ represents a sort of additional "artificial" demand that represents the possibility to turn off electricity generation when the residual demand becomes negative because renewable energies (e.g. wind energy) produce more than consumers demand. The exchange E between the model regions is determined by the model itself but limited by the corresponding net transfer capacities. Due to the transportation of the electricity, a small share s_{loss}^{grid} of the determined amount is lost in the grid.

The electricity generated by (pump) storage plants is limited by the storage capacities as well as by the pump and turbine capacities. Furthermore, the energy amount in the storage W needs to be in balance. It equals the energy amount of the previous period adjusted for the pumped and turbine generated energy (respecting efficiency losses) plus an extra energy amount $w_{natural}$ caused by natural inflow of water.

$$
\begin{aligned}
W(y,p,r) = \; & W(y,p-1,r) \\
& + \text{hours} * \; [U(y,p,r) * s_{pump}^{eff}(y,r) \\
& \qquad - G_{STOR}(y,p,r) * \frac{1}{s_{turb}^{eff}(y,r)} \\
& \qquad + w_{natural}(y,p,r)]
\end{aligned} \tag{6}
$$

[13] An exception is one OCGT technology to ensure feasibility.

[14] The index m is used to indicate the different months of a year. It is referring to subsets of the set of periods belonging to the respective month.

As mentioned before, thermal power plants have to meet minimum output requirements. In the model we present these requirements are taken into account by ensuring that the electricity generation never drops below a technology specific percentage share $s_{min}^{gen}(t,y)$ of the capacity ready-to-operate. To model the efficiency loss by part load operation, the generation is split into generation under full load operation and generation under minimum load operation. The following constraint takes care of both aspects.

$$G_{MIN}(y,p,t) \geq s_{min}^{gen}(y,t) * [C_{RTO}(y,p,t) - G_{FULL}(y,p,t)] \tag{7}$$

Note that:

$$G_{TOTAL}(y,p,t) = G_{MIN}(y,p,t) + G_{FULL}(y,p,t) \tag{8}$$

B. Characteristics of the Linear Program

The model is deterministic as because we assume that all future input parameters are known. Under this assumption of perfect foresight the solution of the model will underestimate real costs. For example, pump storage plants have an advantage in this setting, because they already know the demand and the value of electricity for each future period. Therefore, they are able to adjust previous pumping and electricity generating activity to optimality. Furthermore, thermal power plants can adapt their mode of operation better if all parameters are given.

Additionally, by using historical data for the demand profile, stochastic extreme situations, such as an extremely cold winter, are not modeled explicitly. Therefore, the solution of the model is likely to contain too little capacity reserves. This could be corrected by including a capacity markup on top of the maximal demand in the model.

These characteristics of the electricity market model should be kept in mind for the interpretation of the results, which will be presented in the upcoming section.

V. Results

We show the implications of the different nuclear policy scenarios by calculating the turnover for a reference power plant. The power plant selected is a combined cycle gas turbine from Trianel GmbH. It is situated in Hamm-Uentrop, Germany, has a net generating capacity of 800 MW and was initially taken into operation at the end of 2007. Its expected lifetime of operation is about 30 years.

The calculation is starting in 2012 with every second year until 2030 being a reference year. The last reference year 2030 is representing eight years to include the power plants' dispatch until the end of its lifetime.

The only differences between the three scenarios are their respective nuclear power plant capacities (and the CO_2 prices). All other aspects and parameters are identical.

A. Evaluation

The solution of the LP model generates optimal values for all variables mentioned above. It includes the installed capacities of each vintage class in each year and each region as well as the commissioning and decommissioning of capacity. The (two-hourly) periodical mode of operation and dispatch of each vintage class calculated as well. Furthermore, the operation mode and storage level of (pump) storage plants in the model regions have are determined on a periodical basis. Also, the cross-border flows between the different regions on a periodical basis can be extracted from the solution of the model.

As mentioned before, the solution of an LP also brings along shadow prices (or dual variable values) for the different constraints of the model. A shadow price represents the change in the objective function if the constant right-hand-side of the constraint is altered marginally. If a constraint is not binding in the optimal solution, its shadow price will be zero. From economic theory, the price or value of a product is determined at the intersection of supply and demand. Therefore, the shadow price of the demand constraint can be taken as an estimate of the expected electricity price in a certain period in a certain year and region.

Given the periodical dispatch of each vintage class in combination with the periodical electricity prices, the turnover of each vintage class can be determined. Likewise, the variable production costs can be calculated. From the change in the capacity ready-to-operate startup and shutdown costs of each vintage class can be calculated and annual operating and maintenance costs of the installed capacity can be determined. As the Trianel power plant was already built before our period of observation started, we focus on the profit contribution (and do not include investment costs in our analysis).

To identify the specific revenues and costs of the chosen Trianel CCGT, we use the capacity share of the power plant within the corresponding vintage class as a scaling factor. Taking the present values[15] of all revenues and costs for the Trianel CCGT, the following profits result.

Table I shows that the nuclear plant capacities have a significant impact on the revenues of the Trianel CCGT. The net revenue under the atomic consensus (SC1) and the nuclear phase-out (SC3) are 136 million Euros while the net profit contribution under the energy concept scenario with extended nuclear life-times (SC2) is negative (minus 42 million Euros).

Table I
Revenues and Costs of the Trianel Power Plant (in Mio. €)

	SC1	SC2	SC3
Revenue electricity generation	2,646	1,430	2,610
Variable production costs	-2,153	-1,136	-2,117
Startup and shutdown costs	-87	-66	-87
Fixed costs	-270	-270	-270
Net revenue	**136**	**-42**	**136**

One main reason for this loss in revenue is the low level of full-load hours of the relevant CCGT technology in SC2 compared to SC1 and SC3 respectively. The full-load hours in SC2 are between 30% and 70% lower than in the other two scenarios. The generation that is done by combined cycle gas

[15] The date chosen for the calculation of the present value is the 1st of January 2012.

turbines in SC1 and SC3 is partly taken over by the additional nuclear power plants in SC2.

Fig. 3 shows the annual electricity price averages in Germany (also called base prices). SC1 and SC3 have almost identical prices except for the years 2018 and 2020. In these two years, their nuclear capacities differ the most and influenced the power plant portfolio accordingly. In SC2, the additional nuclear capacities which have lower variable production costs than other technologies pushed the base prices down.

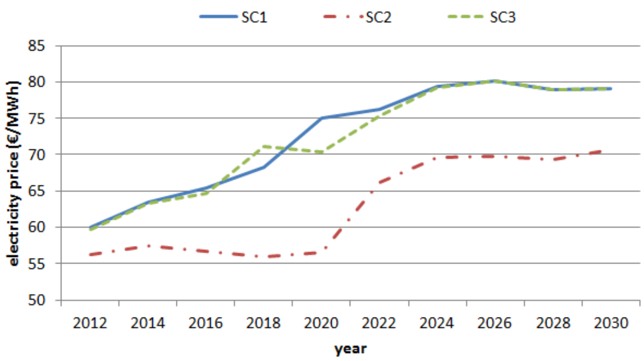

Fig. 3. Electricity prices of the three different scenarios.

VI. Conclusion

This paper presented an electricity market model that is capable of making both long-term investment decisions as well as short-term dispatch choices. It includes 10 European countries and runs over a time horizon of 25 years. The model was used to predict the development of the power plant portfolio and the actual dispatch of electricity. These were used to determine revenues and costs of a specific combined cycle gas turbine in Germany. Considering three political scenarios regarding the German nuclear policy, we showed that the extension of nuclear life-time in the energy concept scenario would have implied a negative impact on the profitability of the other power plants. In particular, we quantified this effect for a gas-fired CCGT power plant. Our calculations demonstrate political risks for investors.

We see potential for further research in some aspects. The solution of the LP as presented above will exhibit exactly enough capacity to cover the highest demand in the system. However, as we assumed perfect foresight, a safety margin might be needed. An additional constraint for extreme situations could be incorporated to implement this. Furthermore, uncertainty could be included in the model, e.g. using the approach described in Müsgens and Neuhoff (2005). Furthermore, aspects such as demand responsiveness of customers or the influence of balancing power could be included as well.

VII. Appendix

TABLE II
OVERVIEW OF RELEVANT VARIABLES AND PARAMETERS

Variable/Parameter	**Description**
$C_{ADD}(y,t)$	commissioned capacity of technology t in year y
$C_{AVAIL}(y,p,t)$	available capacity of technology t in year y in period p
$C_{DOWN}(y,p,t)$	shutdown capacity of technology t in year y in period p
$C_{INST}(y,t)$	installed capacity of technology t in year y
$C_{OH}(y,m,t)$	capacity in maintenance of technology t in year y in month m
$C_{RTO}(y,p,t)$	capacity ready-to-operate of technology t in year y in period p
$C_{SUB}(y,t)$	decommissioned capacity of technology t in year y
$C_{UP}(y,p,t)$	startup capacity of technology t in year y in period p
$d_{res}(y,p,r)$	residual demand in region r in year y in period p
$E(y,p,r,r')$	exchange flow from region r to r' in year y in period p
$e_{net\_exp}(y,p,r)$	net export of region r to unmodelled regions in year y in period p
$f_p^d(p)$	discount factor for period p
$f_y^d(y)$	discount factor for reference year y
$G_{FULL}(y,p,t)$	power generation in full load of technology t in year y in period p
$G_{MIN}(y,p,t)$	power generation in minimum load of technology t in year y in period p
$G_{STOR}(y,p,r)$	power generation by (pump) storage plants in year y in period p in region r
$G_{SURPLUS}(y,p,r)$	renewable energy amount turned off in year y in period p in region r
$G_{TOTAL}(y,p,t)$	total power generation of technology t in year y in period p
$hours$	number of hours per period
$m_{mp}(m,p)$	binary indicator whether period p belongs to month m
$m_{rt}(r,t)$	binary indicator whether technology t exists in region r
$s_{OH}(y,t)$	yearly share of capacity in overhaul of technology t in year y
$s_{invest}^{cost}(y,t)$	share of investment costs of technology t in year y
$s_{pump}^{eff}(y,r)$	pump efficiency in region r in year y
$s_{turb}^{eff}(y,r)$	turbine efficiency in region r in year y
$s_{min}^{gen}(y,t)$	minimum load share of technology t in year y
s_{loss}^{grid}	grid loss share during exchange
$U(y,p,r)$	energy amount pumped out of the system by pump storage plants in year y in period p in region r
$w_{natural}(y,p,r)$	additional energy amount due to natural inflow in region r in year y in period p
$W(y,p,r)$	energy amount stored in (pump) storage plants in year y in period p in region r
$years(y)$	number of years represented by reference year y
Z	total costs
$z_{down}(y,p,t)$	shutdown costs of technology t in year y in period p
$z_{fixed}(y,p,t)$	operating and maintenance costs of technology t in year y in period p
$z_{invest}(y,t)$	investment costs of technology t in year y
$z_{up}(y,p,t)$	startup costs of technology t in year y in period p
$z_{full}^{var}(y,p,t)$	variable production costs under full load production of technology t in year y in period p
$z_{min}^{var}(y,p,t)$	variable production costs under minimum load production of technology t in year y in period p

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