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An Electricity Market Model with Generation Capacity Investment under Uncertainty

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AN ELECTRICITY MARKET MODEL WITH GENERATION CAPACITY EXPANSION UNDER UNCERTAINTY

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Abstract. This article presents an electricity dispatch model with endogenous electricity generation capacity expansion for Germany over the horizon 2010-2035. The target is to quantify how fuel and carbon price risk impacts investment incentives of thermal power plants. Results point to findings which are in line with general theory: Accounting for stochasticity increases investment levels overall and the investment portfolio tends to be more diverse.

Keywords: electricity market; equilibrium model; generation expansion; uncertainty; market power.¹

¹ Conference Paper for Verein für Socialpolitik Jahrestagung 2012 - updated 29 October 2012

1. Introduction

This paper investigates the power plant expansion planning of electric utilities under uncertainty about long-term trends in fuel prices. General idea and hypothesis is that expectations of oil and gas price evolutions are one of the main drivers for investment decisions into power plants (Weber and Swider, 2004; Geiger, 2010). By reflecting the uncertain nature of the fuel price evolution, we expect to replicate and understand the portfolio effect of investment choices and explain postponement of investment.

Power plant investment decisions are complex and risky given long amortization periods, the volatility of electricity market prices, uncertainty regarding competitors' investment and generation decisions as well as the high regulatory risks. Investments often involve substantial sunk costs, rendering the investment decision almost irreversible. Numerous studies deal with power plant investment decisions without taking appropriate account of uncertainties (DENA, 2010; EWI et al., 2010; EC, 2011). Ninghong et al. (2008) demonstrate how ignoring uncertainties significantly undervalues the operational flexibility and can even result in an insufficient investment into power plants. The representation of uncertainty is thus an important aspect for a realistic depiction of investment choices.

In principle, two different streams of literature can be found which carry-out quantitative investigations on uncertainties and their impact on investment. One line of literature deals with a detailed treatment of uncertainties through scenario analysis, risk management, decision theory and real options. A second stream of literature deals with a decent treatment of game theoretic aspects, including market analysis and the behaviour of competitors. Real options valuation serves as a stepwise solution procedure to investment planning which is able to account for adaptive behaviour and learning effects (Dixit and Pindyck, 1994). In these real option models, the uncertain parameter evolves according to a random process, firms decide (strategically) on the timing when to install additional capacities. While the insights provided are rich in terms of timing, there is a complete abstraction from spot markets and operational inflexibilities. A further caveat of econometric real options valuation is that it hardly takes into account feedback between investment and market interactions (prices) and strategic aspects can be modelled only on a superficial basis. This is where equilibrium models step in. Equilibrium models as presented in the present paper can incorporate long-term uncertainty and multi-stage decision-making, thus accounting for the real option character of investment. They depict the relation between costs and the market prices and the ability of firms to adjust their production after investment. At the same time the models allow for a decent technical depiction of electricity dispatch and they can include strategic action due to market power, which happens to be relevant for the German electricity market (Weigt et al., 2010; Traber and Kemfert, 2011).

Strategic capacity choices have been extensively discussed in recent literature in a Cournot spot market setting (Gabszewicz and Poddar, 1997; Murphy and Smeers, 2005). There are further examples of studies on strategic power plant investment, partly under uncertainty (Ventosa et al., 2002; Grimm and Zoettl, 2008; Geiger, 2010; Pineau et al., 2011a, 2011b). All in all, these studies are fairly theory-oriented but modest in their application. There exist virtually only duopoly analysis with few constructive results according to Grimm and Zoettl (2008).

In view of the lack of applications, we intend to fill this gap by providing a case study analysis of the German electricity market with a combined investment and dispatch model. The contribution of our work is to extend the existing electricity market equilibrium model Esymmetry (Traber and Kemfert, 2011) with endogenous investment and include long-term uncertainty. The main research question of this article is how fuel and carbon price risk impact investment decisions. Besides, we attempt to answer what level of fuel and CO₂ prices spur investment into the various power plant technologies.

2. Model

The electricity market model is a partial equilibrium model based on the power dispatch model outlined in Traber and Kemfert (2011). The original dispatch model is complemented with endogenous capacity investment, stochastic elements and a multi-period perspective. The investment planning constitutes an open-loop, multi-period stochastic equilibrium. In open-loop equilibria, all decisions for all stages are set at the start of the game (Basar and Olsder, 1999). The equilibrium model reflects oligopolistic markets in a Cournot competition environment, i.e. market prices adjust to players' quantity decisions. Strategic decision variables are a sequence of investments and operations. The risk-neutral investor has information on the likeliness of each scenario. Scenarios differ in their assumptions on fuel and carbon prices.

The mixed complementarity program is solved with the PATH solver in the General Algebraic Modeling System (GAMS). It is formulated as extensive-form stochastic equilibrium problem. Firms maximize their individual expected and discounted profits over the modeling period, i.e. revenues net of production costs and fixed investment cost (Equation 0). The set of variables comprises investment as well as ramping and generation decisions. Several firms have the possibility of exerting market power while a competitive fringe is regarded as price taker. This setting makes it necessary to solve the problem as mixed complementarity problem (MCP) with Karush-Kuhn-Tucker conditions (KKT). Firms are constrained by capacity restrictions and a market balance (Equations 0 to 0). Demand is represented with a linear inverse demand function (Equations (8) and (9)). Generation and ramping costs are affected by fuel cost, efficiency, variable operation and maintenance cost, CO₂ emissions cost as well as depreciation cost for power plant cycling (Equations (10) to (12)). The Appendix entails a nomenclature and the KKT conditions (13)-(22).

Profit

$$\max_{Q,X,L} \pi = \sum_a pr^a [d^a [w^a (\sum_{t=1}^T \sum_{n=1}^N (P^{t,a} (TQ^{t,n,a}) Q^{i,t,n,a} - c_Q^{n,a} Q^{i,t,n,a} - c_L^{n,a} L^{i,t,n,a})) - c_X^n X^{i,n,a}] + sv^{n,a} X^{i,n,a}] \quad (1)$$

Market balance

$$P^{t,a} \quad P^{t,a} - \sum_{i=1}^I \sum_{n=1}^N (p_0^t - slp^{t,a} (Q^{i,t,n,a} + res^{t,a} - d_0^t)) \geq 0 \quad (2)$$

Generation capacity limit

$$\kappa^{i,t,n,a} \quad (\bar{q}^{i,n,a} + \sum_{a \in pred(a)} X^{i,n,a}) av^n - Q^{i,t,n,a} \geq 0 \quad (3)$$

Load gradient upper limit

$$\delta^{i,t,n,a} \quad \bar{l}^{i,t,n,a} (\bar{q}^{i,n,a} + \sum_{a \in pred(a)} X^{i,n,a}) av^n - L^{i,t,n,a} \geq 0 \quad (4)$$

Load gradient lower limit

$$\lambda^{i,t,n,a} \quad L^{i,t,n,a} - Q^{i,t,n,a} + Q^{i,t-1,n,a} \geq 0 \quad (5)$$

Capacity expansion limit

$$\rho^{i,n,a} \quad \bar{x}^{i,n} - X^{i,n,a} \geq 0 \quad (6)$$

Reserve energy minimum

$$\gamma^{t,a} \quad \sum_{n=1}^N \sum_{i=1}^I [(\bar{q}^{i,n,a} + \sum_{a \in pred(a)} X^{i,n,a}) av^n - Q^{i,t,n,a}] - \underline{q}^a \geq 0 \quad (7)$$

Intercept

$$int^{t,a} = p_0^{t,a} - d_0^{t,a} slp^{t,a} \quad (8)$$

Slope

$$slp^{t,a} = \frac{p_0^{t,a}}{(d_0^{t,a} \sigma)} \quad (9)$$

Discount factor

$$d^a = e^{-0.08(a'-a)} \quad (10)$$

Generation cost

$$c_Q^{n,a} = \frac{c_f^{n,a}}{\eta^n} + c_o^n + \frac{emf^n}{\eta^n} \phi^a \quad (11)$$

Ramping cost

$$c_L^{n,a} = s^n c_f^{n,a} + c_d^n + emf^n s^n \phi^a \quad (12)$$

3. Application to the German Power Market

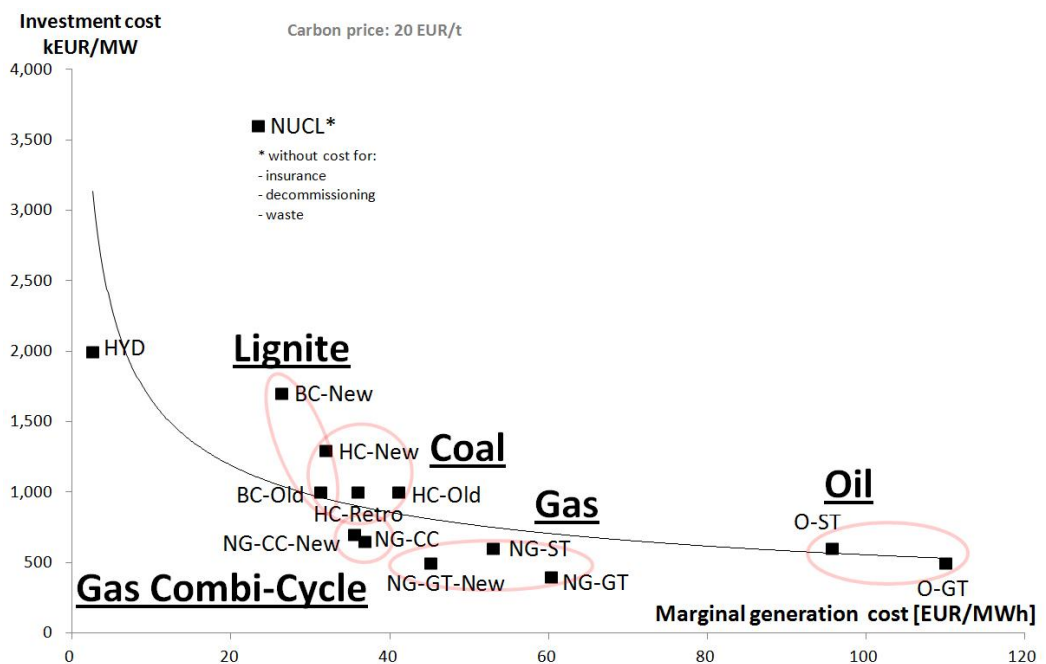


Figure 1: Generation and investment cost. (Source: Own illustration)

The model is applied to the case of Germany with 4 major players exerting market power and a competitive fringe. The model horizon goes from 2010 to 2035 at the investment stage and includes five representative days with hourly time resolution at the dispatch stage (120h). 14 ‘dispatchable’ generation technologies are considered and renewable energy feed-in is represented as exogenous feed-in. Data is collected to replicate 2010 market behavior and assumptions are made regarding the long-term evolution of key input parameters, in line with Traber and Kemfert (2011). These key input parameters include investment cost, generation cost, fuel cost, renewable energy feed-in, reference demand, reference spot market prices, discount rate and salvage values. Details can be found in Figure 1 and Table 5 in Appendix.

World Energy Outlook projections (IEA, 2011a) are used to build a scenario structure for fuel and carbon prices as detailed in Figure 2 and Table 1. The IEA scenarios comprise the "current policies scenario", where no policies beyond those adopted in 2011 will be enforced. This scenario translates into high oil and gas prices while carbon prices are low. The "new policies scenario" is somewhat a middling scenario, where more stringent than current policies are adopted notably in the vehicle sector. This scenario is characterized by a moderate price path. On the other extreme, the IEA describes the "450ppm scenario" as a situation with 50% likelihood of meeting the 2 °C climate policy target. This scenario naturally reflects high carbon prices but low oil and gas prices due to reduced demand. Transition probabilities between scenarios are all set to equal shares throughout all scenario nodes. As can be seen in Figure 2, we end up with 16 states and 6 stages for the time horizon 2015-2035.

Table 1: Fuel and carbon prices in the scenarios. (Source: Based on IEA (2011a), where available)

<u>New Policies Scenario</u>							
		<u>2010</u>	<u>2015</u>	<u>2020</u>	<u>2025</u>	<u>2030</u>	<u>2035</u>
Oil	\$/barrel	78.1	102	108.6	113.6	117.3	120
Coal	\$/Ton	99.2	103	107	110	111	112
Gas	\$/MBTU	7.5	9.6	10.4	11.1	11.7	12.1
Lignite	\$/Ton	45	49	50	51	52	53
CO ₂	EUR/Ton	20.0	25	30	35	40	45
<u>450 ppm Scenario</u>							
Oil	\$/barrel	78.1	97	97	97	97	97
Coal	\$/Ton	99.2	103	109	112	117	119
Gas	\$/MBTU	7.5	9.4	9.8	9.8	9.7	9.4
Lignite	\$/Ton	45	49	50	51	52	53
CO ₂	EUR/Ton	20.0	30.0	45	75	95	120
<u>Current Policies Scenario</u>							
Oil	\$/barrel	78.1	106.3	118.1	127.3	134.5	140
Coal	\$/Ton	99.2	100	92	83	73	69
Gas	\$/MBTU	8.0	9.8	11.0	11.9	12.6	13
Lignite	\$/Ton	45	49	50	51	52	53
CO ₂	EUR/Ton	20.0	22	25	30	35	40

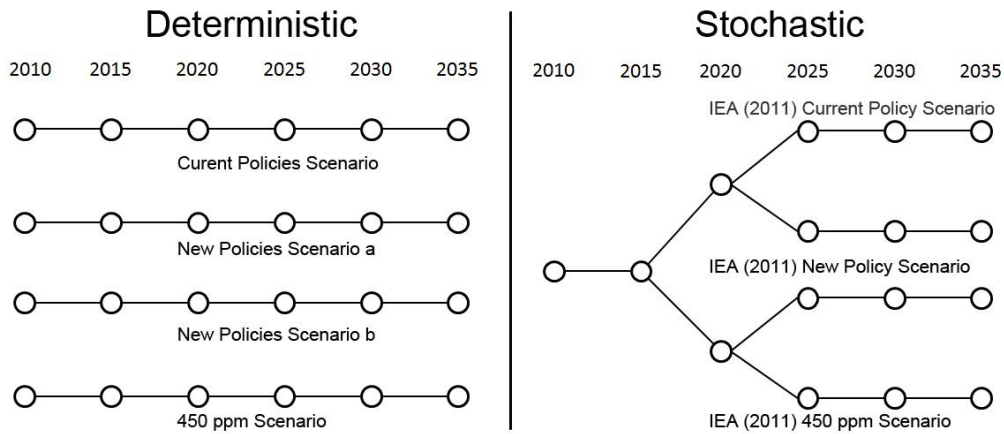


Figure 2: Scenario tree structure. (Source: Own illustration)

4. Results

In what follows, the extensive-form stochastic problem is compared with its deterministic expected-value counterpart and other forms of deterministic equivalents. The expected value problem corresponds to the average of all scenarios at each stage of the stochastic model. The deterministic perfect information model considers each of the four scenario paths separately. The comparison between stochastic and deterministic models allows for insights into the value that agents would attribute to attaining more certainty and it shows how ignoring uncertainty risks leading to lower profits. The results section is sub-divided into an analysis of profits, investments, prices, market structure and a subsequent discussion.

In analyzing the impact of investment risk on the objective value, some basic concepts of stochastic programming are referred to and their outcome is compared. The concept of the value of the stochastic solution (VSS) is commonly used in the stochastic programming community as indicator for the added value of explicitly considering probabilities instead of expected values. Another useful concept is the expected value of perfect information (EVPI). It represents how much one would be willing to pay to receive information on the realization of future events (Birge and Louveaux, 1997).

4.1 Profits

Table 2: Expected profits over the range 2010-2035. (Source: Own illustration)

(m EUR)	ESS	EV	EEV	EPI	VSS		EVPI	
Eon	35.7	36.4	35.5	36.0	0.2	0.49%	0.3	0.85%
EnBW	14.4	14.0	14.5	14.5	-0.1	-0.50%	0.1	0.40%
RWE	22.3	22.4	22.2	22.5	0.1	0.54%	0.1	0.65%
Vattenfall	18.6	17.1	18.4	19.5	0.2	0.96%	0.9	4.53%
Fringe	20.2	20.7	18.8	20.3	1.4	6.91%	0.1	0.59%
Total	111.2	110.7	109.4	112.7	1.8	1.61%	1.5	1.34%

EV	=	$\min f[E(x)]$		Deterministic expected value problem
EEV	=	$E[\min f(E(x))]$		Expectation with EV solution
EPI	=	$E[\min f(x)]$		Expectation under perfect information
ESS	=	$\min E[f(x)]$		Expected stochastic solution
VSS	=	$ESS - EEV$	≥ 0	Value of the stochastic solution
EVPI	=	$EPI - ESS$	≥ 0	Expected value of perfect information

Table 2 shows that profits are highest in the deterministic model under perfect information (EPI). This outcome represents ideal circumstances but it is not attainable in reality. Naturally, the expected value (EV) profits and the expectation of the EV (EEV) profits are both lower than the EPI profit. They are also lower than the expected stochastic solution (ESS) profit. This is because the stochastic model allows for adaptation to extreme scenario realizations and agents can then perform well in each scenario. In contrast, the expectation of the EEV allows for no flexibility and the EV problem entails no extreme events which could raise profits. It is possible to show that the solutions of the deterministic model would perform worse in reality compared to the predictions of the stochastic model. The VSS is used as indicator how much worse a deterministic model performs in a stochastic world and it figures at around 9 % in this application, with huge variations across players. For some players, VSS and EVPI are negative. Zhuang (2005) and Egging (2010) explain that such curiosity can occur in equilibrium modeling as opposed to optimization. Since agents compete in their optimization program, some agents may end up worse off in a stochastic equilibrium, which can translate into a negative VSS.

4.2 Investment

Table 3: Investment levels under perfect competition and with 9 % discounting. ‘CC-New’ is Gas Combined Cycle; ‘HC-New’ are hard coal plants. Unit is MW. (Source: Own illustration)

Stochastic ESS	<i>(mean values)</i>	2010	2015	2020	2025	2030	2035	
	CC-New	0	0	6,465	0	0	0	6,465
	HC-New	0	4,500	6,279	50	0	0	10,829
		0	4,500	12,744	50	0	0	17,294

Deterministic EV		2010	2015	2020	2025	2030	2035	
	CC-New	16,481	0	0	0	0	0	16,481
		16,481	0	0	0	0	0	16,481

As concerns the optimal decisions of investment sequences, taking into account fuel price risk strengthens the overall level of investment into flexible plants in comparison to the deterministic EV model (Table 3). This is due to the occurrence of extreme scenarios where agents gain from investing large amounts into one specific technology, once a particular scenario materializes. Another result sound with theory is that investment choices become more diverse in the stochastic model, owing to the portfolio effect. Agents flexibly adapt to newly arising information on scenario realizations and thus choose fairly different technology portfolios at each scenario node, making it overall a diverse mixture of investment choices. In this application, agents invest in new hard coal plants as well as combined cycle gas-fired plants (Table 3). We also see the timing of investment to alter by the presence of imperfect knowledge in a multi-period setting. Agents tend to postpone irreversible investment decisions when holding the option to invest at later periods. As imperfect information unfolds and reduces over time (scenario tree in Figure 2), agents automatically reduce investment risk when postponing decisions.

4.3 Prices

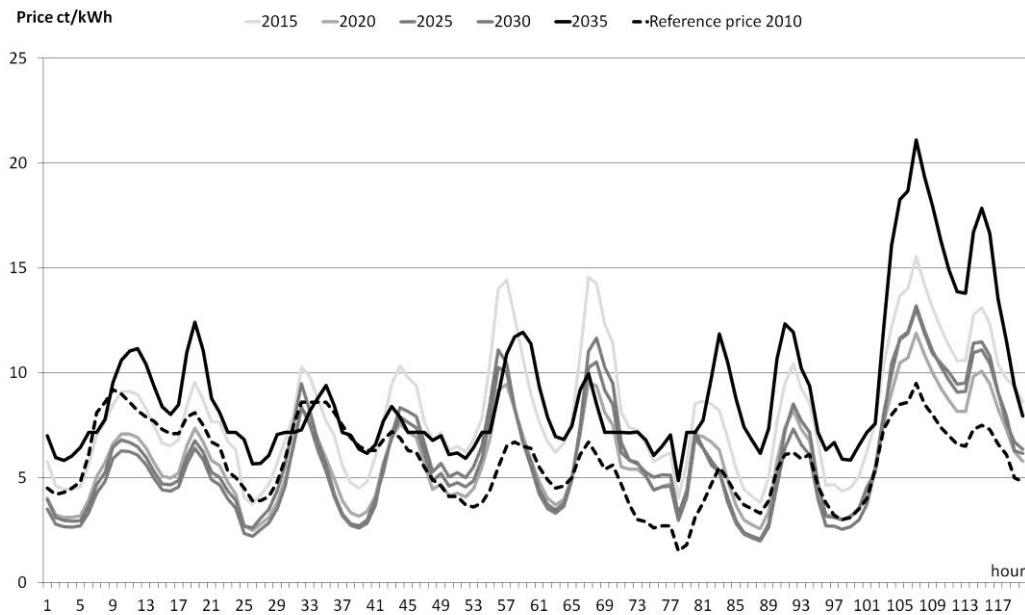


Figure 3: Price profile. (Source: Own illustration)

Figure 3 shows how price profiles alter over the years. We observe price spikes to be more pronounced in later years and prices are in average higher in later years compared to 2010 reference prices. This finding can be explained by rising fuel prices, the increased use of generation technologies with high variable cost and the more intense ramping regime due to stronger fluctuations in renewable energy feed-in. In addition to these effect, several counteracting drivers affect prices. The increasing availability of low-cost renewable energy sources dampens prices due to its zero marginal cost. However this effect can be offset when flexible generation units with high variable cost are increasingly called upon. Additionally, the decommissioning of power plant capacities by 2030 can increase the market share of oligopolistic players and thus the ability of influencing market prices through capacity withholding. This effect can be relativized by the fact that all firms have equal access to the option of increasing its market share by new investment. All in all, upward pressure on prices prevails over downward pressure according to the results reported here.

4.4 Market form

The strategic behavioral assumptions of Cournot competition seems far more appropriate than assuming perfect competition. By comparing with historic spot prices from the European Energy Exchange (EEX) and historic generation levels, it is clear that Cournot competition results are better in replicating observed prices. This is in line with Traber and Kemfert (2011) and Weigt and Hirschhausen (2008) which indicate how oligopolistic structures affect electricity prices in the German market. Therefore, the analysis here concentrates on the case of imperfect markets. Note that accounting for market shares and market power in imperfect markets drives results into a certain direction: It drastically reduces investment of strategic players. As a matter of fact, very little investment is performed by oligopolistic players in the Nash-Cournot setting, while we see investments being undertaken by all players in the perfect competition scenario. Large strategic firms have a smaller incentive to invest since they expect a price that includes a mark-up in addition to full cost recovery, as opposed to price-taking agents. Predicted strategic capacity choices of the four dominant market players are consistently lower in oligopolistic markets compared to the benchmark level in the presence of perfect competition.

5. Discussion of model limitations

Several aspects of model design and assumptions deserve further reflection and they are discussed here below.

1) There are limitations to how capacity investments and expansions can be modeled in an MCP. This type of expansion is integer-valued, a characteristic that cannot be accommodated easily in an MCP. To preserve convexity in our model we assume that any size of expansion can be made, i.e., all expansion variables are continuous.

2) It is difficult to estimate future revenues from investment because these strongly depend on price spikes. Using typical weeks instead of an entire year perspective risks to neglect the significance of extreme events such which cause price spikes. This is a general problem to investment models for electricity markets which is equally encountered by related studies (Grimm and Zoettl, 2008). In order to address this problem to a sufficient extent, the representative week includes days with extremely high demand and low renewable energy feed-in.

3) Current discussions among practitioners questions whether a system of marginal cost pricing with a high percentage of low-cost renewables can provide sufficient incentives for investment in gas-powered plants. According to De Vries and Heijnen (2008), energy-only markets do not provide sufficient incentives for investment. That is why considerations beyond energy-only markets may be required, i.e. including capacity markets and yields from heat production in co-generation. In this model application here, we see no room to include capacity markets in its full detail since these would require a further refinement in the temporal resolution of the model towards 15-minutes steps. However, we do include minimum reserve capacity requirements and the possibility of a capacity premium.

4) In the current application, the model does neither treat grid capacity restrictions nor does it deal with imports and exports of electricity from other nodes or the possibility of storing electricity, although these factors can be crucial in reducing the need for generation capacity expansion. This implies that the amount of investment into power plants is rather overstated in this model. The possibilities of trade, storage and demand-side-management would alleviate upward pressure on market prices and thus reduce investment incentives for power plants.

6. Conclusions

In this paper, long-term developments of fuel and carbon prices are analyzed as drivers of investment decisions into thermal power plants. General theory on risk management suggests that agents invest more in stochastic models, but delay investment in a multi-stage setting as uncertainty unfolds over time. Overall, the investment portfolio becomes more diverse with the stochastic model. A stylized application of the model to the German case replicates theory. We show that agents do postpone investment decisions, they increase overall levels of investment, they receive reduced profits and they diversify technology choices when confronted with uncertainty.

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8. Appendix

Table 4: Nomenclature

Indices and Sets

i in I	Player
t in T	Hour
n in N	Generation technology
a in A	Year (deterministic) or scenario (stochastic)
NS	Subset of Nash players i
$Pred(a)$	Predecessor node set of a
$Succ(a)$	Successor node set of a

Variables

$P(t,a)$	Price	EUR
$X(i,n,a)$	Investment (Expansion)	MW
$Q(i,t,n,a)$	Production	MWh
$TQ(n,t,a)$	Total production of all firms	MWh
$L(i,t,n,a)$	Load gradient	MW
$\lambda(i,t,n,a)$	Shadow price of ramp-up constraint	EUR/MW
$\delta(i,t,n,a)$	Dual of load gradient definition	EUR/MW
$\kappa(i,t,n,a)$	Shadow price of capacity constraint	EUR/MW
$\rho(i,n,a)$	Shadow price of capacity expansion limit	EUR/MW
$\gamma(t,a)$	Shadow price of reserve capacity requirement	EUR/MW
$\theta(i,t,a)$	Market share	%

Parameters

$pr(a)$	Probability	%
$w(a)$	Number of weeks per period	
$d(a)$	Discount rate	%
$int(t,a)$	Intercept of demand curve	
$slp(t,a)$	Slope of demand curve	
$d_0(t)$	Reference demand	EUR
$p_0(t)$	Reference price	EUR
$res(t,a)$	Renewables and CHP feed-in	MW
σ	Periodic price elasticity of demand	%
$sv(n,a)$	Discounted salvage value	EUR
$c_d(n)$	Marginal depreciation while ramping	EUR/MW
$c_o(n)$	Operating cost	EUR/MWh
$c_f(n,a)$	Fuel cost	EUR/MWh
$c_x(n)$	Investment cost	EUR/MW
$c_Q(n,a)$	Marginal cost of generation	EUR/MWh
$c_L(n,a)$	Marginal ramping cost	EUR/MW
$c_{re}(n,a)$	Marginal ramping emission cost	t/MW
$c_e(n,a)$	Marginal emission cost	t/MWh
$\Phi(a)$	Emission price	EUR/t
$emf(n)$	Emission factor	t/MWh
$av(n)$	Availability	%
$s(n)$	Ramp-up fuel requirement	MWh/MW
$\eta(n)$	Efficiency	%

$\bar{q}(i,n,a)$	Installed capacity	MW
$\bar{l}(i,n,a)$	Maximum load gradient	%/hour
$\bar{x}(i,n,a)$	Maximum capacity expansion	MW
$\underline{q}(a)$	Minimum reserve capacity requirement	MW

Karush-Kuhn-Tacker Conditions

$$pr^a sv^{n,a} - pr^a d^a c_X^n - \rho^{i,n,a} + \sum_{t=1}^T \sum_{a \in succ}^A (\kappa^{i,t,n,a} + \bar{l}^n \delta^{i,t,n,a} + \gamma^{t,a}) av^n \leq 0 \quad \perp X^{i,n,a}, \forall(i, n, a) \quad (13)$$

$$pr^a d^a w^a [P^{t,a} - slp^{t,a} \sum_n^N Q^{i \in NS, t, n, a} - c_Q^{n,a}] - \lambda^{i,t,n,a} + \lambda^{i,t+1,n,a} - \kappa^{i,t,n,a} - \gamma^{t,a} \leq 0 \quad \perp Q^{i,t,n,a}, \forall(i, t, n, a) \quad (14)$$

$$-pr^a d^a w^a c_L^{n,a} + \lambda^{i,t,n,a} - \delta^{i,t,n,a} \leq 0 \quad \perp L^{i,t,n,a}, \forall(i, t > 1, n, a) \quad (15)$$

$$P^{t,a} - \sum_{i=1}^I \sum_{n=1}^N (p_0^t - slp^{t,a} (Q^{i,t,n,a} + res^{t,a} - d_0^t)) = 0 \quad \perp P^{t,a}, \forall(t, a) \quad (16)$$

$$(\bar{q}^{i,n,a} + \sum_{a \in pred(a)}^A X^{i,n,a}) av^n - Q^{i,n,t,a} \geq 0 \quad \perp \kappa^{i,t,n,a}, \forall(i, t, n, a) \quad (17)$$

$$\bar{l}^n (\bar{q}^{i,n,a} + \sum_{a \in pred(a)}^A X^{i,n,a}) av^n - L^{i,t,n,a} \geq 0 \quad \perp \delta^{i,t,n,a}, \forall(i, t > 1, n, a) \quad (18)$$

$$L^{i,t,n,a} - Q^{i,t,n,a} + Q^{i,t-1,n,a} \geq 0 \quad \perp \lambda^{i,t,n,a}, \forall(i, t > 1, n, a) \quad (19)$$

$$\theta^{i,t,a} \left(\sum_{i \in NS^t}^I \sum_{n=1}^N Q^{i,t,n,a} \right) - \sum_{n=1}^N Q^{i,t,n,a} = 0 \quad \perp \theta^{i,t,a}, \forall(i \in NS, t, a) \quad (20)$$

$$\bar{x}^{i,n} - X^{i,n,a} \geq 0 \quad \perp \rho^{i,n,a}, \forall(i, n, a) \quad (21)$$

$$\sum_{n=1}^N \sum_{i=1}^I (\bar{q}^{i,n,a} - Q^{i,t,n,a}) - \underline{q}^a \geq 0 \quad \perp \gamma^{t,a} \quad (22)$$

Table 5: Technical and economic parameters

		Investment cost	Fuel emission (d)	Efficiency (d)	O & M costs (d)	Ramp-up fuel (d)	Ramp-up depreciation (d)	Maximum load gradient (g)	Available (d)	Fuel price (f)
		kEUR/MW	kg/kWh	%	ct/kWh	kWh/kW	ct/kW	%/hour	%	ct/kWh
Pumped hydro	HYD	-	0	1	0.26	0	0	100	75	0.00
Nuclear	NUC-L	-	0	0.34	0.1	16.7	0.17	15	86	0.76
Lignite	BC-Old	-	0.4	0.38	0.26	6.2	0.1	40	85	0.29
Lignite new	BC-New	1700 [1950 (b)]	0.4	0.43	0.1	6	0.3	50	100	0.29
Coal old	HC-Old	1300 (b) [800 (e)]	0.34	0.34	0.2	6.2	0.15	40	82	0.65
Coal retrofit	HC-Retro	1100	0.34	0.38	0.1	6	0.5	40	100	0.65
Coal new	HC-New	1300 [1950 (a), 2250 (b)]	0.34	0.43	0.1	5.5	0.5	50	100	0.65
Gas combi cycle old	NG-CC	650	0.2	0.58	0.13	3.5	1	50	86	1.66
Gas combi cycle new	NG-CC-New	700 [950(b), 530 (f)]	0.2	0.6	0.12	2.9	1	55	90	1.66
Gas steam turbine	NG-ST	600	0.2	0.4	0.15	4	1	36	86	1.66
Gas gas turbine old	NG-GT	400 (b)	0.2	0.35	0.15	1.1	1	100	86	1.66
Gas gas turbine new	NG-GT-New	500 [400(b)]	0.2	0.47	0.13	1.1	1	100	90	1.66
Oil steam turbine	O-ST	600	0.28	0.38	0.15	4	0.5	36	84	3.02
Oil gas turbine	O-GT	500	0.28	0.33	0.15	1.1	0.5	100	84	3.02

a) (IEA et al., 2010) – exchange rate EUR-USD 1.33

b) (EWI et al., 2010) – for 2020

c) (Konstantin, 2007)

d) Updated based on Traber and Kemfert (2011)

e) (Genc and Sen, 2008) – exchange rate EUR-USD 1.33

f) (IEA, 2011a)

g) (IEA, 2011b)