POWER PLANT INVESTMENTS UNDER FUEL AND CARBON PRICE UNCERTAINTY

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Abstract

Until 2030, important replacement investments are needed in the EU power plant sector, which are expected to attain between 300 and 600 GW of installed capacity. Also elsewhere in the world the generating capacities built up during the high growth phase in the 1960s and 1970s will have to be replaced and new capacities have to be installed, leading according to recent IEA studies to investments in about 5,000 GW of new generating capacities between 2000 and 2030. Even if part of the investment will certainly be done in renewable power plants such as wind and fuel cells, there will be most likely also a need for new thermal power plants.

These investments represent important strategic decisions for electric utilities since power plants require large investment sums and, once effectuated, they are predominantly sunk costs. Yet there is considerable uncertainty on what power plants will be most profitable for companies and/or society over their lifetime. Primary energy prices are one major source of uncertainty, another, related one, are future CO2 prices. Notably with the raise of gas prices since mid 1999, it has become rather questionable whether gas-fuelled power plants are the option of choice for new thermal power stations. Coal, nuclear and (where available) lignite are potential alternatives.

In this context, novel methods are needed to assess the profitability under uncertainty of the various types of thermal power plants. In principle the application of a real options approach (as notably developed by Dixit and Pindyck 1994) seems desirable, but it is complicated by the possibilities of fuel switching with endogenous output prices and simultaneous uncertainties on loads, fuel prices, technologies and policies. A simple extrapolation of current price patterns in continental Europe to the future seems problematic since price patterns until recently hardly reflected any capacity constraints, given that in the past substantial overcapacities existed. But this situation will come to an end with the definitive closure of older units. Therefore, future electricity prices and investments have to be treated simultaneously, thinking of a transition towards (stochastic) long-term price equilibrium. This basic idea will be developed in the presentation taking the static, deterministic long-term equilibrium as analysed in peak-load pricing theories as starting point. .Stochastic extensions to the peak-load-pricing concept are however necessary both to include short-term variations, i.e. mostly load and renewable production fluctuations, and longer term uncertainties – related notably to fuel prices and CO2 prices. For the latter a backward induction approach, similar to those used in real option theory, is developed to derive simultaneously dynamic stochastic price equilibria and the value of different power plants in the long term perspective. The major difference in comparison to the conventional real option models is that prices are treated as endogenous. This is done in a setting with multiple production technologies (gas, coal and other plants) and with time-varying load. The developed approach is finally applied to a simplified model of the German power market, showing that the optimal investment path is rather different from the optimal investments obtained without fuel price uncertainty.

Keywords: electricity markets, investment, uncertainty

1 Introduction

Until 2030, the requirements for replacement investments in the EU power plant sector are expected to be between 300 and 600 GW (cf. Voß 2002, Birol 2003). Also elsewhere in the world the generating capacities built up during the high growth phase in the 1960s and 1970s will have to be replaced and new capacities have to be installed, leading to investment requirements of about 5,000

GW between 2000 and 2030 (cf. IEA 2002, Birol 2003). This requires strategic decisions for electric utilities since power plants require large investment sums and represent, once effectuated, to a large extent sunk costs1.

Since electricity demand has been growing steadily albeit slowly in the last decades, there is hardly any uncertainty on the necessity of building up new capacities – although in the first years after the liberalization of European electricity markets only few people considered the issue of future power plant investments (cf. e. g. Voß 2000, Voß 2002a, b, Weber, Voß 2001, Pfaffenberger 2002). But a first uncertainty in this field is whether political measures will lead to a situation where all new generation capacities are supplied by subsidized or regulated segments within the electricity sector - notably generation from renewable sources and/or generation from combined heat and power including fuel cells. In Germany, this possibility is sometimes evoked. But overall, such a scenario seems not very likely, given that fuel cells will certainly not be fully competitive in the next decade, other combined heat and power generation is currently only competitive in selected applications and wind – as the most important renewable source – requires always conventional back-up capacities in order to cope with the intermittent character of wind generation. A further alternative, mentioned sometimes, is the increased use of electricity imports to avoid new construction in one specific country. But this is certainly not a solution for Europe as a whole and even for a larger country like Germany, recent analyses indicate that the potential for imports is limited through several factors: current grid constraints between countries, the requirements of system stability and limitation of transportation losses and the expectation that in the longer run technology and fuel costs will tend to level out within Europe, thus not creating any large incentives for installing power plants far from the point of use. (cf. Fichtner, Cremer 2003). Overall, the general uncertainty on the need for new conventional plants is rather low and obviously these will be mostly thermal power plants, since hydro potentials have been already exploited to a large extent in the past.

Nevertheless, there is considerable uncertainty on what power plants will be most cost efficient over the considered lifetime. This is partly due to uncertainties of primary energy prices which can be modelled as stochastic processes (cf. section 4.3.1). Notably with the raise of gas prices since mid 1999, it has become rather questionable whether gas-fuelled power plants are the option of choice for new power stations. Coal, nuclear and (where available) lignite are potential alternatives.

In this context, novel methods are needed to assess the profitability under uncertainty of the various types of thermal power plants. In principle the application of a real options approach (as notably developed by Dixit and Pindyck 1994) seems desirable, but it is complicated by the possibilities of fuel switching with endogenous output prices and simultaneous uncertainties on loads, fuel prices, technologies and policies. A simple extrapolation of current price patterns to the future seems problematic since current price patterns hardly reflect capacity constraints, given that in the past substantial overcapacities existed in continental Europe. But this situation is coming to an end with the definitive closure of older units. Therefore, future electricity prices and investments have to be treated simultaneously, thinking of a transition towards long-term price equilibrium. This basic idea will be developed and applied in the following sections starting with the static, deterministic long-term equilibrium in section 2. It has been shown that this long-term equilibrium corresponds to the one derived from the concept of peak-load pricing already developed in regulated markets. Section 3 then develops a backward induction approach, similar to those used in real option approaches, to derive simultaneously dynamic stochastic price equilibria and the value of different power plants in the long term perspective. This approach is then applied in section 4.

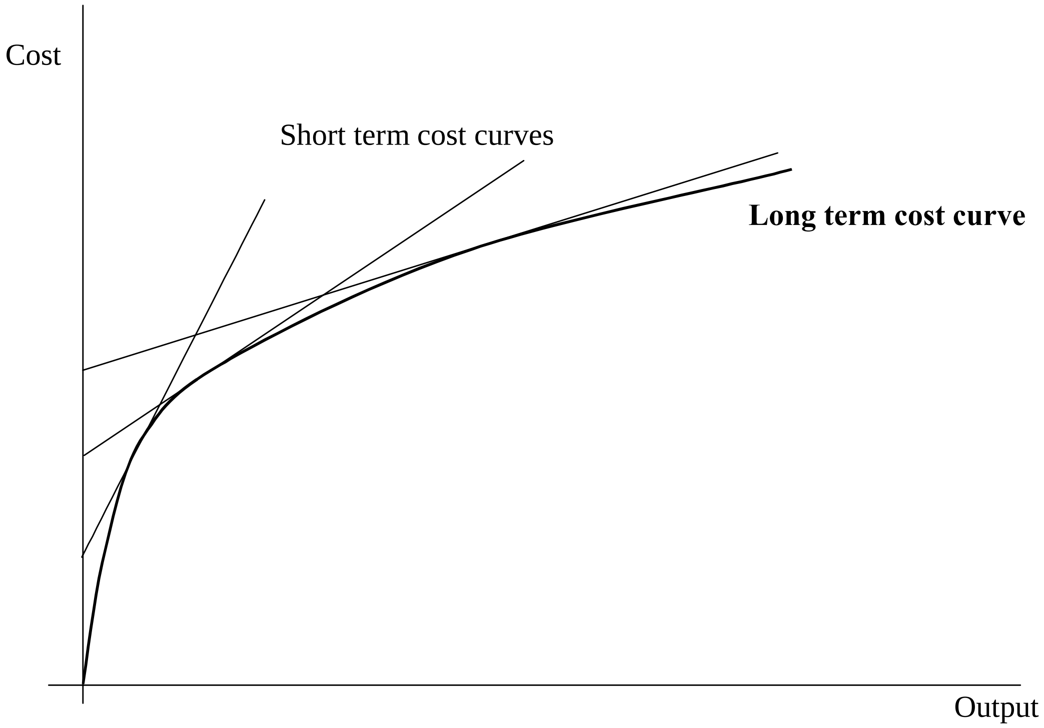
2 Static, deterministic long term market equilibrium - the concept of peak load pricing

Companies will always attempt to shape their decisions with long term impacts so as to move from the short term marginal cost curve to the long term marginal cost curve (see Varian 1992). The latter constitutes an envelope and lower bound of all short-term (i.e. fixed capital stock) cost curves (cf. Figure 1), since at different price ratios, the minimum costs achievable at fixed capital stock will at

[1] At least in continental Europe so far hardly any market for second-hand power plants exists – in the UK and the US sales of used power plants have been more frequent in the context of disvestment strategies.

best correspond to the minimum costs achievable when the capital stock is flexible, too. The expression “long-term” is therefore not associated with a precise time span but rather designates a time span sufficiently long so that all restrictions through existing capital stocks have vanished. If usual power plant lifetimes are taken to be 40 years, then the long-term would be at maximum 40 years away. But in virtue of the argument given above, the long-term equilibrium will already influence the investment decisions of today.

Figure 1: Long-term cost functions as lower bound to short term cost functions



Electricity, at least at the wholesale level, is a rather homogenous good. Nevertheless, it has not a uniform price as discussed in section 4, notably due to its non-storability and the resulting necessity for a supply and demand balance at each single point in time. As shown in section 4.1.1, the equilibrium price will at each point in time be equal to the marginal generation costs of the last unit needed to fulfil the demand restriction. This argument can be directly generalized to the long-term equilibrium case with the slight, but important difference, that the last unit needed in the peak load time, has not only to recover its variable generation costs but also its fixed costs, because otherwise it would not be built. The same holds obviously for the other generation technologies.

Hence, the problem defined in equations (4-1) to (4-4) for the short-term has to be extended, making capacities not a right-hand side constraint but a decision variable. This requires notably the inclusion of the (annualized) capital costs $C_{Inv,u}$ into the objective formulation and correspondingly a shift of the capacity parameters from the right to the left side of the inequalities:

$$\min_{y_{u,t},K_u} C \tag{1}$$

$$\begin{aligned} C &= \sum_t \sum_u C_{Op,u,t} + \sum_u C_{Inv,u} = \sum_t \sum_u p_{F,u,t} h_u y_{u,t} + \sum_u a(\rho, L_u) c_{Inv,tot,u} K_{PL,u} \\ &= \sum_t \sum_u c_{Op,u} y_{u,t} + \sum_u c_{Inv,u} K_{PL,u} \end{aligned} \tag{2}$$

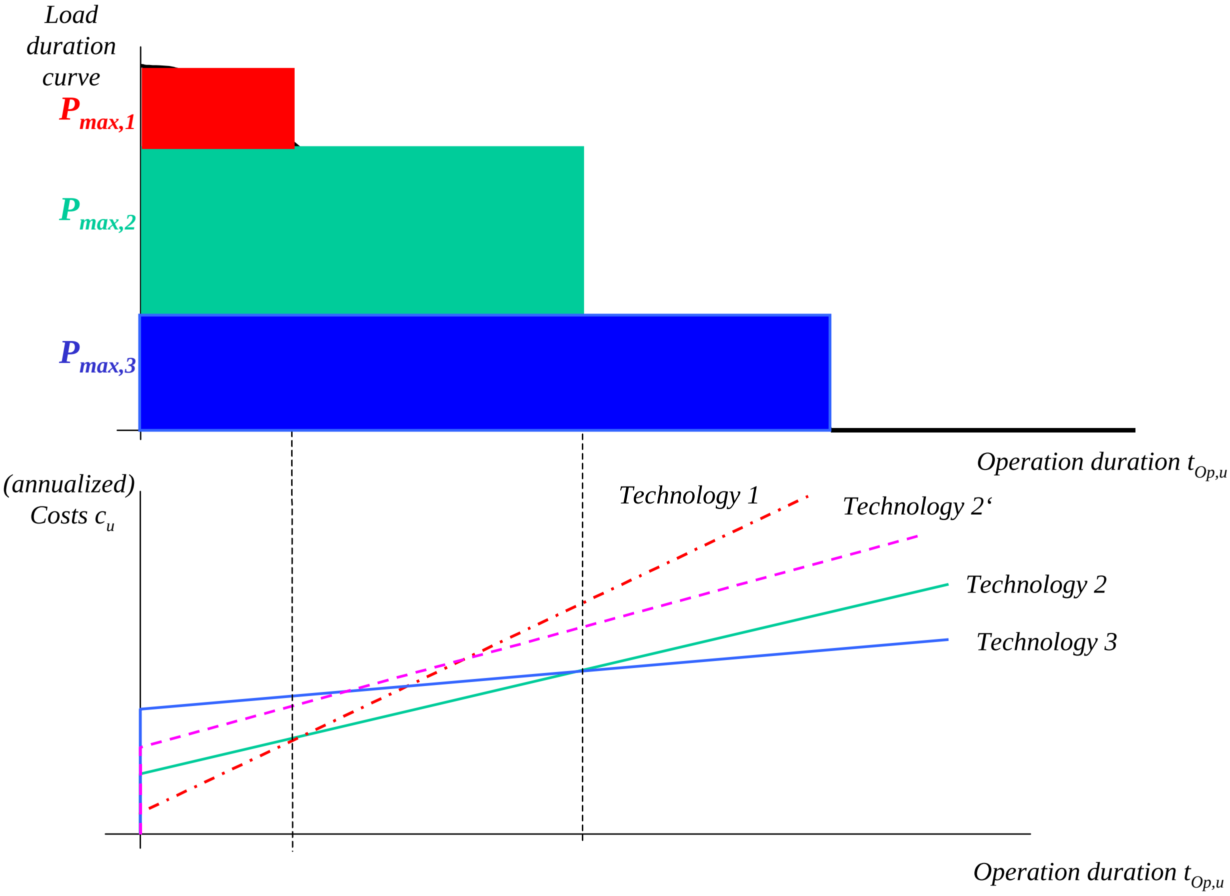
$$\sum_u y_{u,t} \geq D_t \tag{3}$$

$$y_{u,t} - K_{PL,u} \leq 0 \tag{4}$$

As in the short term case, demand elasticity is assumed to be zero. It has been shown (cf. e.g. Oren 2000 for a short summary) that the optimal solution to the technology choice problems can be obtained graphically as shown in Figure 2. In the lower part, the total (annualized) costs per MW c_u are plotted as a function of total annual operation hours $t_{Op,u}$:

$$t_{Op,u} = \left(\sum_t y_{u,t} \right) \Big/ K_{PL,u} \tag{5}$$

Figure 2: Graphical solution to the peak-load pricing problem



From equation (2), it is then obvious that (at time-invariant fuel prices):

$$c_u = C_u / K_u = p_{F,u} h_u t_{Op,u} + a(\rho, L_u) \tag{6}$$

Thus c_u is a linear function in $t_{Op,u}$ with the capital costs $a(\rho,L_u)$ representing the intersection point on the vertical axis and the variable costs $p_{F,u}$ h_u corresponding to the slope of the line. In the example depicted in Figure 2, clearly technology 1 is the cheapest for operation duration between 0 and t_1, technology 2 is cheapest between t_1 and t_2 and technology 3 is then the most economical for all operation times exceeding $t_{2.}$ Since in the upper part, the load in all time segments t has been ordered by decreasing values yielding the so-called load duration curve, this may be directly used to determine the optimal installed capacity for each technology. Starting with the highest load duration, the optimal capacity for technology 3 (the base-load plants) is determined as the load level which is exceeded in at least t_2 hours per year. In statistical terms, the (1 – t_2/8760)-quantile of the load duration curve is chosen as optimal capacity $K_{PL,2}$. By similar reasoning, the optimal capacity for technology 2 is determined as the difference between the (1 – t_1/8760)- and the (1 – t_2/8760)-quantile of the load duration curve. And finally the peak load technology 1 has to have an equilibrium capacity equal to the difference between the maximum load x_{max} and the (1 – t_1/8760)-quantile.

A technology, which at all possible numbers of operating hours is more expensive than another one, will not be selected as part of the efficient portfolio. This is the case of technology 2’ in

Figure 2: the cost curve is throughout above the cost curve for technology 2, so it is said to be "dominated" by technology 2 and it would be inefficient to use it. Formally, a technology *u'* is inefficient if

$$\forall t_{Op}\ \exists u\ c_u\left(t_{Op}\right) < c_{u'}\left(t_{Op}\right) \qquad (7)$$

i.e., for all operating hours $t_{Op,u}$, there exists another technology *u* (not necessarily always the same) which is less costly than *u*. Such technologies can be excluded a priori from the optimization problem at given prices.

Prices are mathematically obtained as solutions of the dual problem corresponding to the one formed by equations (1) to (4). By the same reasoning, as long as capacities are not scarce, at least for one type of plant, prices will not exceed the variable costs of the last unit used for satisfying demand. If the capacity constraint of the last unit gets binding, then (shadow) prices will get up to the level of annualized investment costs for the peaking unit (cf. equation 4-8). If several hours with the same peak load level exist, the investment costs would be divided evenly between these hours, but in the case of a single deterministic peak load hour, this single hour would bear theoretically the whole capacity costs. Graphically, the prices correspond to the derivative of the efficient cost frontier $c^*(t_{Op})$ and the price peak at hour 0 (or hour 0 to n) arises from the step in the cost functions at $t = 0$, which corresponds to the capital costs of the technologies.

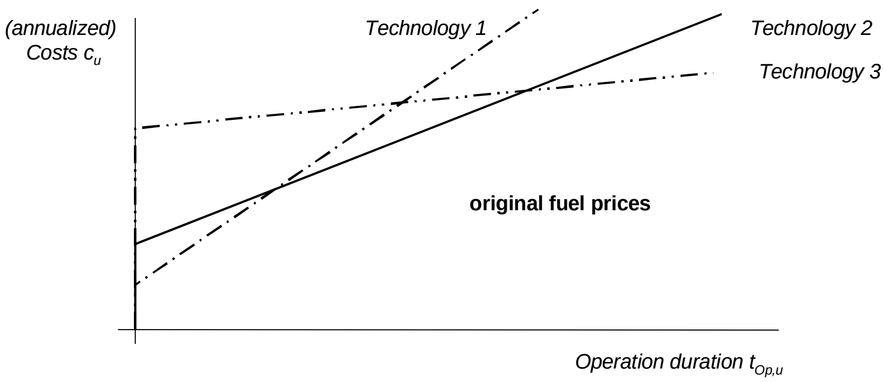
3 Dynamic stochastic long term price equilibria - a backward induction approach

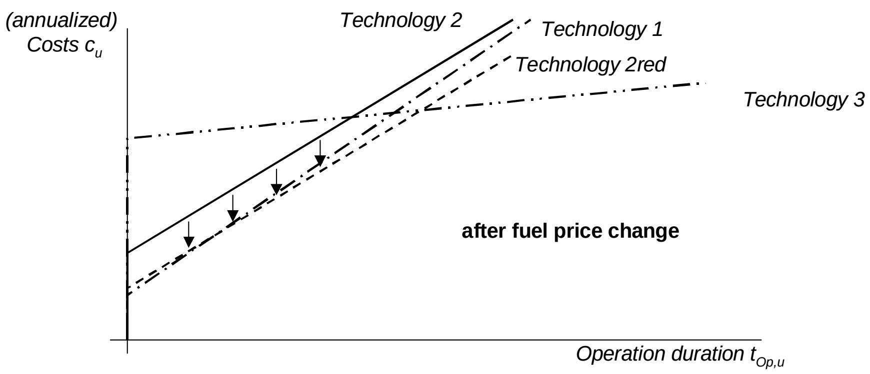
The major market risk for any power plant investment in the longer run is that fuel prices (and/or technology) develop in a way that a once-built power plant is not competitive any more. Thereby two cases have to be distinguished: one possibility is that the technology is no longer part of the efficiency frontier at all. Another is that the range of efficient operation hours (and consequently the optimally installed capacity) of the technology decreases. In both cases, the capacities already installed can still be operated, but they have to accept a reduced operation margin (cf. Figure 3). Yet, if on the contrary the range of efficient operation hours increases, this does not induce any extra profit for units already installed. It creates rather an incentive to install more units of the same type. Hence, if such a fuel price uncertainty exists, the owner of the power plant will require a higher return on investment in the first period as compensation for the risks incurred in later periods.

But in order to derive valuable results for the single investor, it is obviously necessary to treat the whole industry equilibrium. Dixit and Pindyck (1994) develop general methods to deal with the investment-price-equilibrium under uncertainty at the industry level and they also treat several application examples taken from the electricity industry, but they do not analyze the practically relevant setting which includes simultaneously fuel switching, fuel price uncertainty and endogenous output prices.

Obviously, in this setting an analytical solution to the dynamic price-investment equilibrium is hardly possible. Weber (2004) shows that fuel switching turns out to complicate already the static price-investment equilibrium in a way, that analytical solutions become hardly feasible. Therefore a numerical approach is developed in the following. Firstly, the general problem formulation is given in section 3.1 and a general solution methodology developed in section 3.2.

Figure 3: Impact of primary energy price changes on competitiveness of generation technologies and resulting return on investment





3.1 Basic problem

Dixit and Pindyck (1994) derive the industry equilibrium from an analysis of the optimal decisions of individual firms. But they then show that the industry equilibrium is also welfare optimal. Therefore, an equivalent approach is to formulate the welfare optimization problem for investment under uncertainty. As in most of the analysis of Dixit and Pindyck, issues of market power are neglected in the following. As starting point the stochastic but static problem formulations discussed in the previous sections are taken. To simplify somewhat, demand uncertainty and demand price elasticity are neglected as in section 2, so that the problem of welfare optimization is equivalent to a problem of cost minimization.

In the dynamic setting, now a double time index has to be considered: the first one, labelled *T*, is running over the planning periods and the second one *t* is running over the hours within the planning period. Furthermore, a scenario index *s* has to be added to distinguish the different possible states of the world (reflecting notably different fuel prices).

Formulating the problem in discrete time in view of a later numerical treatment, a recursive form of the cost function to be minimized is (cf. Weber 2004 for details):

$$\begin{aligned} C_{T,s}\left(\mathbf{K}_{\mathbf{PL},T,s},\mathbf{y},\mathbf{y}_{tot};\tilde{\mathbf{K}}_{\mathbf{PL},T-1,s_0}\right) &= b(\rho,1,d_T)\sum_t\sum_u c_{Op,u,1,s}\,y_{u,T,s,t}+\sum_u c_{Inv,u}K_{T,s,u}+\\ &\quad b(\rho,d_T,d_T)\sum_{s'}\Pr_{s\to s'}C_{T+1,s}{}^{*}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T,s}\right)\\ \therefore\qquad & y_{u,T,s,t}\le\tilde{K}_{\mathbf{PL},T,s,u} \\ & y_{tot,T,s,t}\le\sum_u y_{u,T,s,t} \\ & \tilde{K}_{\mathbf{PL},T,s,u}\le\tilde{K}_{\mathbf{PL},T-1,s_0,u}+K_{T,s,u}-\zeta_{T-1\to T}\left(\tilde{K}_{\mathbf{PL},T-1,s_0,u}\right)\end{aligned} \qquad (8)$$

Hence the sum of the costs for operating the system in the current period $c_{Op,u,t,s}\,y_{,u,T,s,t}$ plus necessary investments $c_{Inv,u}\,K_{T,s,u}$ plus the probability weighted sums of minimal costs C^* for the subsequent periods are minimized under the capacity and the load constraints for each time segment. The third restriction describes the evolution of total capacities $\tilde{K}_{\mathbf{PL},T,s,u}$ per plant type u as a result of investments $K_{T,s,u}$ and scrapping $\zeta_{T-1\to T}\left(\tilde{K}_{\mathbf{PL},T-1,s_0,u}\right)$. For scrapping, different rules can be envisaged, such as the exponential decay and the finite lifetime ("sudden death") rules considered by Dixit and Pindyck (1994), or the logistic vintage specific decay rule investigated by Schuler (2000).

The duration d_T of the planning period T can be one year or more, assuming that operation during these years is similar. The present value factor $b(\rho,1,d_T)$ is therefore used in equation (8) as a multiplicative factor on the operation costs. The general definition used here is:

$$b(\rho, d_1, d_2) = \sum_{\tau=d_1}^{d_2} \frac{1}{(1+\rho)^\tau} \tag{9}$$

This allows to use directly the factor $b(\rho,d_T,d_T)$ for discounting from the period T+1 to T. If the scenarios s, s' etc. span up the total uncertainties in the decision problem and if the outcomes in the different scenarios can be hedged perfectly on the financial markets, then the interest rate ρ should be set equal to the risk free interest rate. In all other cases one might chose a higher ρ in order to represent unaccounted risk factors and/or risk aversion of the decision makers (cf. Dixit and Pindyck 1994). A lower ρ (going possibly as low as 0) may be justified in cases where natural resource depletion and intergenerational welfare considerations are included (cf. Pearce 1998).

To complete the recursive problem formulation, the cost function (8) has to be complemented by the formulation of the optimal cost function $C_{T,s}^*$:

$$C_{T,s}^*\left(\tilde{\mathbf{K}}_{\mathbf{PL},T-1,s_0}\right) = \min_{\mathbf{K}_{\mathbf{PL},T,s}\mathbf{y},\mathbf{y}_{tot}} C_{T,s}\left(\mathbf{K}_{\mathbf{PL},T,s}, \mathbf{y}, \mathbf{y}_{tot}; \tilde{\mathbf{K}}_{\mathbf{PL},T-1,s_0}\right) \tag{10}$$

Equations (10) and (8) taken together provide a Bellman equation which can be used for solving the optimal investment problem through backward induction.

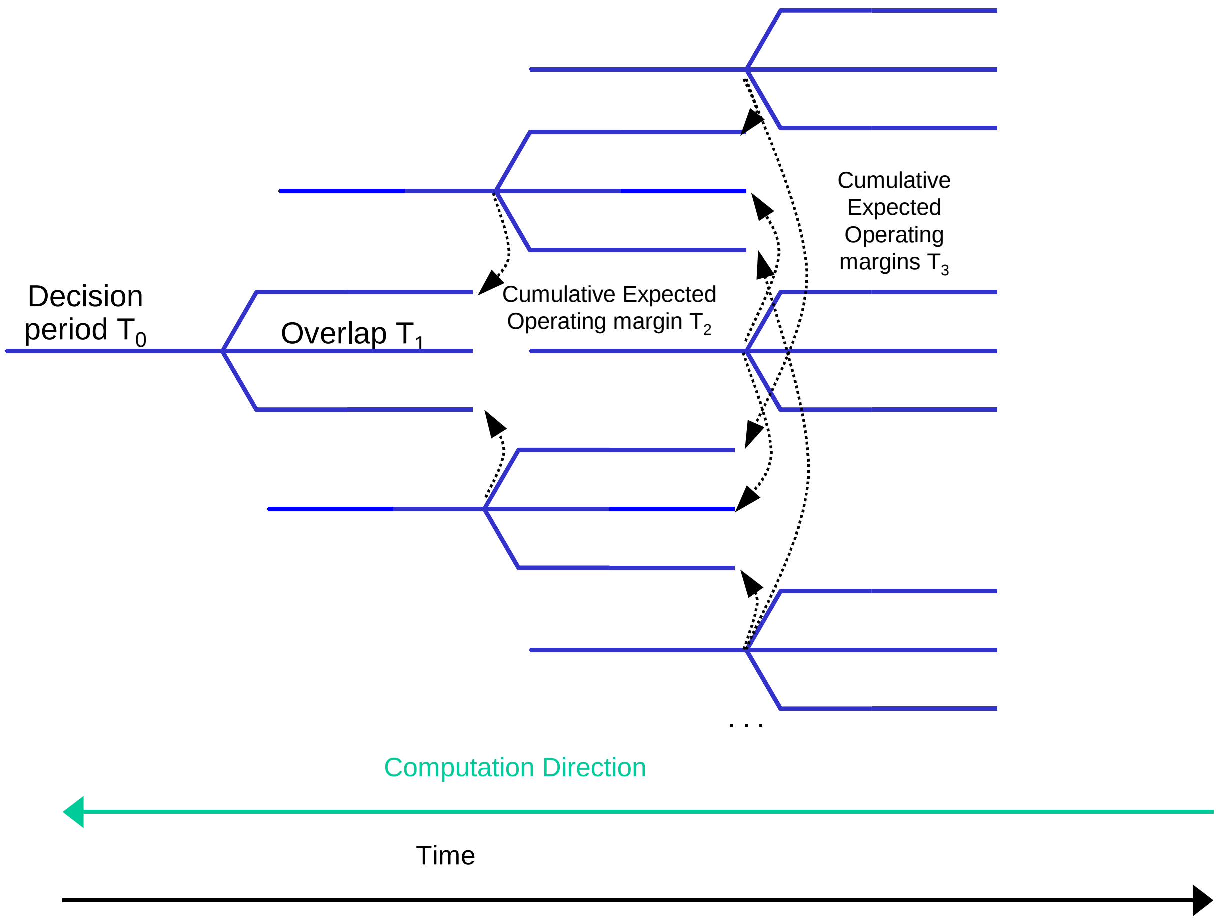
In order to obtain a unique solution, terminal conditions have to be added to the problem. Furthermore the state variables have to be looked at in more detail, to be able to make a meaningful numerical discretization. The issues arising here are discussed in detail in Weber (2004).

3.2 Solution approach

Of course a possible solution strategy for the problem described in the previous section is to formulate a stochastic program encompassing all the future time steps and possible scenarios. However due to the "curse of dimensionality" this approach may rapidly lead to very large and unsolvable problems. An alternative is to decompose the problem, either exactly or using an approximation. Following Weber (2004), an approximate decomposition is used here which allows to obtain accurate and interpretable results without the computational effort required to reach a consistent overall solution.

The basic idea is to work backward through the scenario tree as in option valuation approaches and in dynamic programming. For each node a two stage optimization problem is formulated, so that the uncertainties of the next planning period are explicitly taken into account. The question is then how to cope with the uncertainties at the further decision stages in an at least approximate way. Before giving a formal solution to that problem, a non-formal interpretation is sketched. In fact the decision variables of interest are the capacities to be built at the first stage. The choice of technology at this stage will depend on the fuel prices and other uncertain factors observed at the first, second and further stages, since the earnings accruing from the use of these technologies are distributed over the whole lifetime of the power plant, and the overall cost minimization implies choosing the technology portfolio with the lowest (discounted) lifetime costs. In fact, according to the no-excess profit condition for competitive and efficient markets in neo-classical models, the investment costs of each technology will in the optimum exactly be covered by the (expected) sum of all operating margins, i.e. differences between prices and operating costs, over the lifetime. The operating margins in the first and second stage are included in a two-stage optimization procedure but what is missing is information on the expected operation margins at the third and subsequent stages. These have to be obtained from the solutions of the two stage problems at the next stage (cf. Figure 4).

Figure 4: Backward induction for investment decisions



In fact the expected operating margin will depend on the previously built up stock of the technologies considered. As illustrated in the beginning of section 3 (cf. Figure 3), the operating margin is lowered for an inefficient technology and it is also reduced for a technology of which more than the optimal share is installed.

Formally, the operation margin is introduced through a primal decomposition of the optimization problem. The dynamic equation (8) is first extended to cover explicitly two stages:

$$
\begin{aligned}
&C_{T,s}\left(\mathbf{K}_{\mathbf{PL},T,s},\mathbf{y},\mathbf{y}_{tot};\tilde{\mathbf{K}}_{\mathbf{PL},T-1,s_0}\right)=b(\rho,1,d_T)\sum_t\sum_u c_{Op,u,1,s}\,y_{u,T,s,t}+\sum_u c_{Inv,u}K_{T,s,u}+\\
&b(\rho,d_T,d_T)\sum_{s'}\Pr_{s\to s'}\left(b(\rho,1,d_{T+1})\sum_{t'}\sum_u c_{Op,u,1,s'}\,y_{u,T+1,s',t'}+\sum_u c_{Inv,u}K_{T+1,s',u}+\sum_{s''}\Pr_{s'\to s''}C_{T+2,s'}^{\;*}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}\right)\right)\\
&\therefore\qquad y_{u,T,s,t}\le\tilde{K}_{\mathbf{PL},T,s,u}\\
&\qquad\quad\; y_{tot,T,s,t}\le\sum_u y_{u,T,s,t}\\
&\qquad\quad\; \tilde{K}_{\mathbf{PL},T,s,u}\le\tilde{K}_{\mathbf{PL},T-1,s_0,u}+K_{T,s,u}-\zeta_{T-1\to T}\left(\tilde{K}_{\mathbf{PL},T-1,s_0,u}\right)\\
&\qquad\quad\; y_{u,T+1,s',t'}\le\tilde{K}_{\mathbf{PL},T+1,s',u}\\
&\qquad\quad\; y_{tot,T+1,s',t'}\le\sum_u y_{u,T+1,s',t'}\\
&\qquad\quad\; \tilde{K}_{\mathbf{PL},T+1,s',u}\le\tilde{K}_{\mathbf{PL},T,s,u}+K_{T+1,s',u}-\zeta_{T\to T+1}\left(\tilde{K}_{\mathbf{PL},T,s,u}\right)
\end{aligned}
\qquad (11)
$$

The cost function $C_{T+2,s'}{}^{*}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}\right)$ for the stages *T+2* and onwards is in turn the outcome of an optimization involving a large number of further decision variables. But for the decisions under study it is sufficient to consider its dependency from the capacity variables $\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}$. Therefore instead of the cost function $C_{T+2,s'}{}^{*}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}\right)$ the operating margin $\Theta_{T+2,s'}{}^{*}$ is used which has opposite sign and does not include any costs related to periods beyond *T*+1. The objective function can then be written:

$$C_{T,s}\left(\mathbf{K}_{\mathbf{PL},T,s},\mathbf{y},\mathbf{y}_{tot};\tilde{\mathbf{K}}_{\mathbf{PL},T-1,s_0}\right)=b(\rho,1,d_T)\sum_t\sum_u c_{Op,u,1,s}y_{u,T,s,t}+\sum_u c_{Inv,u}K_{T,s,u}+$$
$$b(\rho,d_T,d_T)\sum_{s'}\Pr_{s\to s'}\left(b(\rho,1,d_{T+1})\sum_{t'}\sum_u c_{Op,u,1,s'}y_{u,T+1,s',t'}+\sum_u c_{Inv,u}K_{T+1,s',u}-\Theta_{T+2,s'}{}^{*}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}\right)\right) \quad \textbf{(12)}$$

$\Theta_{T+2,s'}{}^{*}$ is the value of investments undertaken in *T+1* (or earlier) during period *T+2* and later. It is dependent on the initially installed capacities $\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}$ in *T+1*. Since it is itself the result of an optimization calculus it can be shown to be concave in $\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}$. For any other $\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}{}'$ the following inequality thus holds:

$$\Theta_{T+2,s'}{}^{*}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}{}'\right)\leq\Theta_{T+2,s'}{}^{*}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}\right)+\boldsymbol{\psi}_{\mathbf{PL},T+1,s'}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}{}'-\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}\right) \quad \textbf{(13)}$$

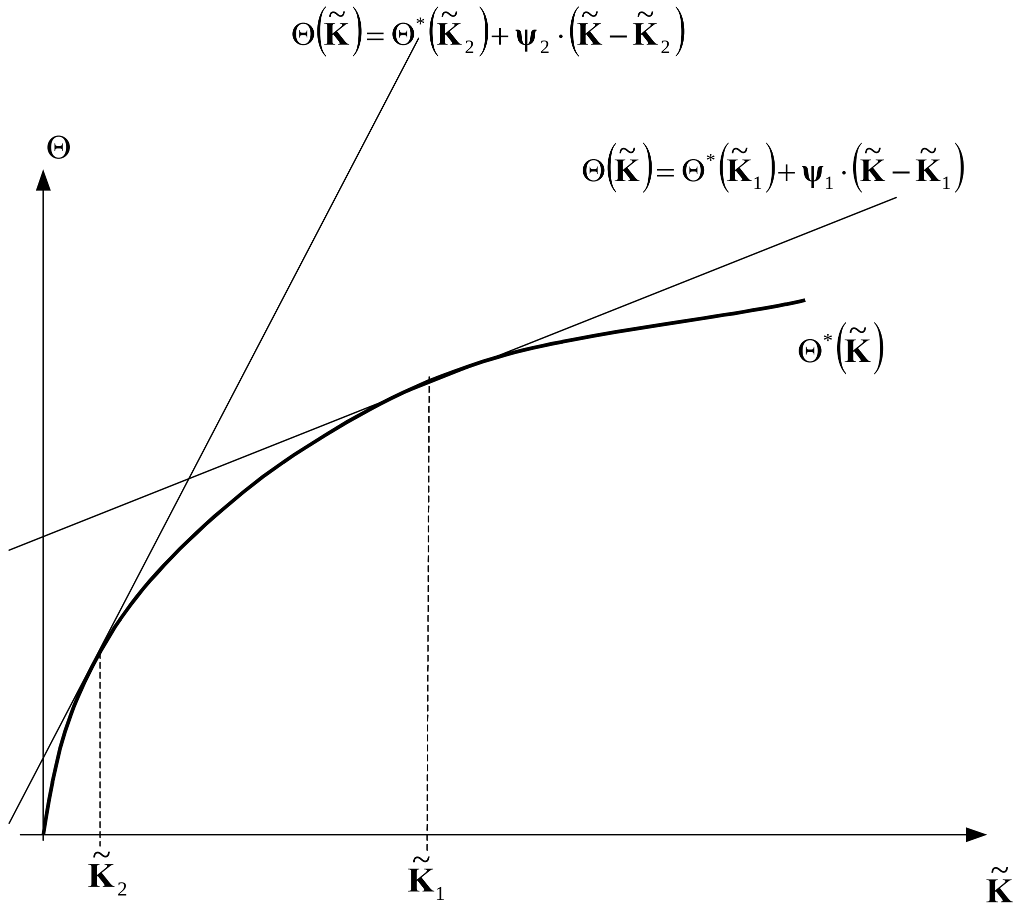
Thereby $\psi_{PL,\,T+1,s'}$ is the (vector of) Lagrangian multipliers of the capacities restrictions involving $\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}$ in the subproblem for $\Theta_{T+2,s'}{}^{*}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}\right)$. The inequality (13) is hence an approximation to the true function $\Theta_{T+2,s'}{}^{*}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}\right)$ and combining several such inequalities will yield a concave hull for the function $\Theta_{T+2,s'}{}^{*}\left(\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}\right)$ (cf. Figure). Combining such inequalities with the objective function (12) corresponds to a Benders' decomposition (cf. Benders 1962, e.g. also Nemhauser, Wolsey 1988). By solving the subproblem on $\Theta_{T+2,s'}{}^{*}$ for several starting points $\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}$, the true function may be approximated by a series of so-called cuts (the straight lines in Figure). These cuts constitute an upper bound to the true value of the operational margin as a function of the initial capacities $\tilde{\mathbf{K}}_{\mathbf{PL},T+1,s'}$.

Benders' decomposition has been applied to electricity planning problems in the short term notably by Pereira and Pinto (1991), but also by Jacobs et al. (1995) Morton (1996) and Takriti et al. (2000). The stochastic dual dynamic programming approach developed by Pereira and Pinto (1991) precisely uses a series of nested Benders cuts to approximate the water value in hydropower scheduling. As Pereira and Pinto do, the proposed approach also does not aim at determining the exact solution to the multi-stage problem, but only an approximate solution achievable through backward induction. But in contrast to the approach of Pereira and Pinto, it is proposed here to use a two-stage stochastic program to determine the expected operational margin. By modelling two stages explicitly the approximation obtained for the cutting plane should be much better than if Monte-Carlo simulations are used to identify initial values for computing the cutting planes.

But still several choices are possible for the initial capacities at the beginning of each two-stage planning problem. Here two obvious choices are considered as in the two-stage example:

- No initial capacities except those already existing at the initial stage T_0 and not scrapped up to $T_{k,s}$: in this case the capacities are chosen optimally given the information available at the first decision stage $T_{k,s}$. The system costs obtained in this setting are a lower bound to the overall system costs since any earlier decision deviating from the optimal decision with information available at $T_{k,s}$ will cause an increase in costs for stage $T_{k,s}$ and possibly for subsequent stages.

Figure 5: Approximation of the operational margin θ through a series of Benders cuts for different initial endowments $\tilde{\mathbf{K}}$



- Pre-existing capacities chosen at stage $T_{k-1,s}$ under myopic expectations: this will provide an upper bound to the expected system costs since it is a simple decision rule which takes into account current information without attempting to anticipate beyond current price. It does not take into account the information available at time $T_{k,s}$ or a priori expectations but it is the minimum level of analysis which each decision maker will usually perform.

For the uncertain variables (fuel and carbon prices), a lattice of possible scenarios is built (cf. Weber 2004, chapter 6, section 5). Then the two stage optimization problem is solved for each node in the lattice, starting from the last period considered. For the last period, a deterministic, static price scenario is assumed (cf. Weber 2004, chapter 9, section 3). For the preceding time steps, the two-stage model is solved using the Benders cuts from the following time step to approximate the operating margin obtainable at the subsequent stages.

An advantage of the approach developed is that it may be adapted to different ways of modelling the operation within one year and the resulting operation margin. Simpler models than the peak load pricing model can be used within one year but also more complex approaches. Notably fundamental, marginal cost models as the one developed in Weber (2002, 2003) to describe the short-term operation can be used to simulate the plant operation within each period. This allows especially including the effect of hydro storage scheduling, start-up costs or other operation restrictions.

4 Application

The developed methodology is applied to the case of investments in the German electricity market. In the following, the key characteristics of the system investigated and the data used are discussed in section 4.1, then the results obtained are discussed in section 4.2.

4.1 Case study analyzed

In order to cope adequately with the characteristics of the power plants installed in Germany, a detailed fundamental model is taken as basis for modelling the system operation. Thereby, demand fluctuations and plant operation are modelled in the same way as they are in fundamental models for the short and medium time horizon (cf. Weber 2003, Weber 2004). This allows for considerable synergies notably with respect to data collection and handling but also for the model equations.

The load duration curve is represented by 144 time segments, with each one representing at most 90 hours. The dynamic constraints linking different hours are taken into account in this approach, allowing to model start-up costs, hydro storage and minimum operation and shut-down times as explained in chapter 4 of Weber (2004).

Since the focus is on modelling the impact of price uncertainties on the optimal investment choice and therefore electricity demand is assumed to remain constant over the planning horizon (In Germany, it has increased by less than 1 % p. a. on average during the last decade). Also technological and political uncertainties, which are currently of considerable importance, are not directly included into the model. For modelling fuel price uncertainty, the econometric fuel price model developed in Weber 2004, chapter 4 is used. It takes oil as the lead world energy carrier. For oil, stochastic, mean-reverting fluctuations around an average price increase as postulated by Hotelling's rule are modelled. For the other primary energy carriers, the ratio to the oil price and the oil price fluctuations are introduced as additionally explanatory variables. This leads to integrated price processes for all fossil fuels except coal. For the case study, 1000 simulation runs are carried out, which are then aggregated to 15 price scenarios per time step for the stochastic model. Since the used fuel model focuses on the changes of (short term) price changes as explained variable it will however not necessarily provide good long term forecasts. The use of fundamental analyses seems preferable to assess the most likely longer term evolution of fuel prices. Here the price scenarios developed by the Enquete-Commission of the German Bundestag on "Sustainable Energy Supply in the Context of Liberalization and Globalization" (cf. Enquete-Commission 2002) are used to define the general development, whereas the fluctuations around this trend are taken from the stochastic model. Given that the stochastic model is formulated in logs of prices, the mean logarithmic price path is calibrated to the pre-specified scenario. Starting in the year 2000, median gas prices are hence expected to decrease until 2005, but afterwards prices are projected to increase at an average annual rate of 1.5 %. For the other fossil fuels rising prices are also expected as a consequence of increasing resource scarcity, notably of oil and gas.

As shown in Figure 6, the price fluctuations around these median values are very large in the case of natural gas, whereas they remain bounded for coal. This is a consequence of the model estimation results showing that natural gas prices are co-integrated with crude oil prices which follows in turn an instationary process. Coal by contrast is not co-integrated and exhibits mean reversion. Given the extreme price spikes simulated for gas prices, the mean value is also considerably bended upwards, whereas the median value, i.e. the value not exceeded in more than 50 % of the simulated price paths is growing much less. The observed gas price development in the last years is also shown in Figure 6, indicating that so far the optimistic expectations on declining gas prices have not been fully met by the reality.

Besides fuel prices, also carbon or CO_2 prices are subject to considerable uncertainty. Gruber (2004) provides evidence that the price process of the available CO_2 price quotes can be modelled adequately by a geometric Brownian motion. However, this leads to extremely high price uncertainty after the year 2010. Consequently, this approach is used to model the price uncertainties until 2010, afterwards the relative price uncertainty is assumed to remain constant. For the average price development it is assumed that the companies will require for their assets in CO_2 certificates the same average return on investment than for generation assets, i.e. 7 % per year[2]. The resulting CO_2 price developments are shown in Figure 7. Certificate allowances for new power plants are not taken into account in this example application.

[2] Such reasoning is strictly valid only if free trading, storing and borrowing on CO_2 certificates is possible. This is however not the case for the current EU trading system.

Figure 6: Upper and lower bounds, median and mean values of price paths for gas and coal

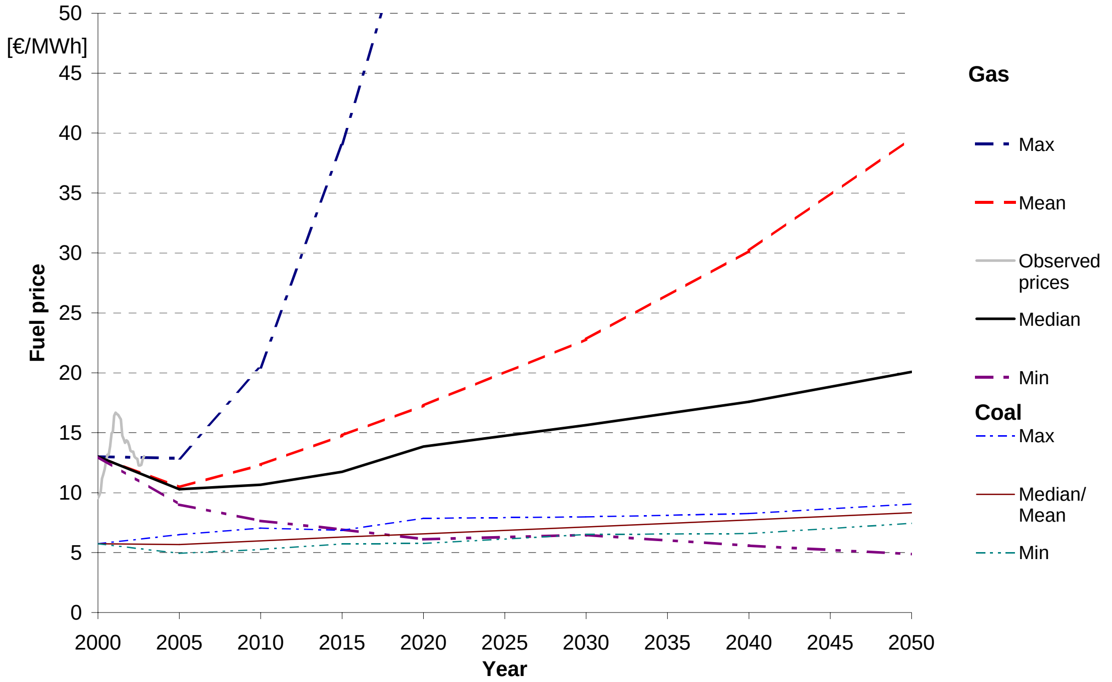
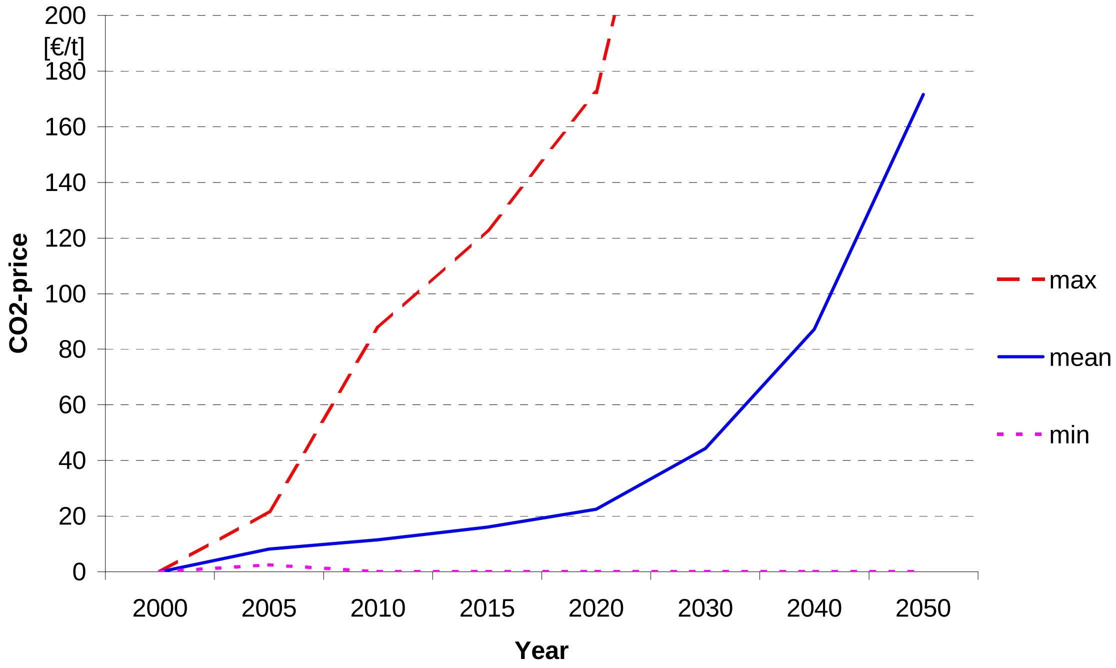


Figure 7: Upper and lower bounds and mean values of price paths for CO_2



Another parameter with considerable impact on the investment choices is the interest rate. Following the discussion in Weber (2004), a real discount rate of 7 % p. a. is applied here to power plant investments.

As investment alternatives, the key alternatives summarized in Table 1 are considered.

Table 1: Technical and economic characteristics of the power plants considered for investment

		Coal fired plant with atmospheric dust combustion	Lignite fired plant with atmospheric dust combustion	Gas turbine	Gas fired combined cycle plant
Net power output	MW	750	750	146	750
Overall fuel efficiency	%	43	40	33	57.6
Planning and construction time	a	5	2	2	4
Economic lifetime	a	35	35	35	35
Duration of decommitment and deconstruction	a	0	0	0	0
Investment costs including site preparation costs and interest payments during construction phase	€/kW	1050	1350	230	450
Decommissioning and deconstruction cost	€/kW	38	38	38	38
Fixed operation costs	€/kW	44	13	11	20
Variable costs besides fuel costs	€/MWh	2.2	1.7	1.2	1.2

Source: Fraktionen von CDU/CSU und FDP (2002), own calculations

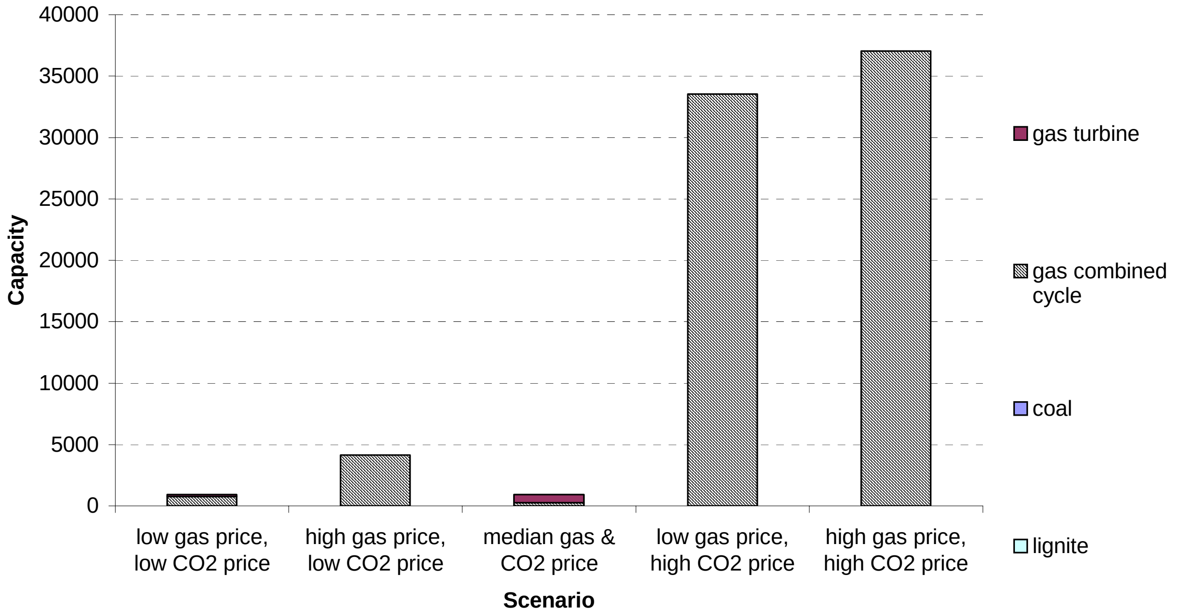
In line with the current political will and legal situation in Germany, investments in nuclear plants are not considered here. For gas-fired plants the current exemption to mineral oil taxation is assumed to be prolongated in the future. Distributed and renewable technologies are not taken into account since it is expected that they will only contribute substantially to electricity generation in the next decade if they are supported and subsidized through specific political instruments. The introduction and modification of the corresponding political instruments clearly contributes to increasing the uncertainty for conventional electricity generation investments, by notably increasing the uncertainty on the load to be covered by conventional plants. But for the promoted technologies the uncertainty is usually reduced, in the case of fixed feed-in tariffs (as currently applied e.g. in Germany, France and Spain) the market price uncertainty is even fully eliminated[3].

4.2 Results

Under the aforementioned conditions, almost no investment is occurring in the year 2005. For the year 2010, investments depend strongly on the scenario, which is reached. In Figure 8, the investment in four extreme and one median scenario are shown. The extreme scenarios are obtained by combining the lowest resp. highest gas prices with the lowest and highest CO_2 prices. Obviously, the optimal investment decision for most scenarios is to postpone investments further in the future. Yet with high CO_2 prices in 2010, the investment in new gas fired plants is more advantageous than to continue to operate the existing, often coal- and lignite-fired plants. This is mainly due to the fact that with high CO_2 prices in 2015, the probability for high CO_2 prices in the further future is also increased. Somewhat surprisingly, investment in gas-fired combined cycle plants is at low CO_2-prices somewhat higher with high gas prices than with low gas prices. Apparently, the new plants are then used to substitute existing oil- and gas-fired plants.

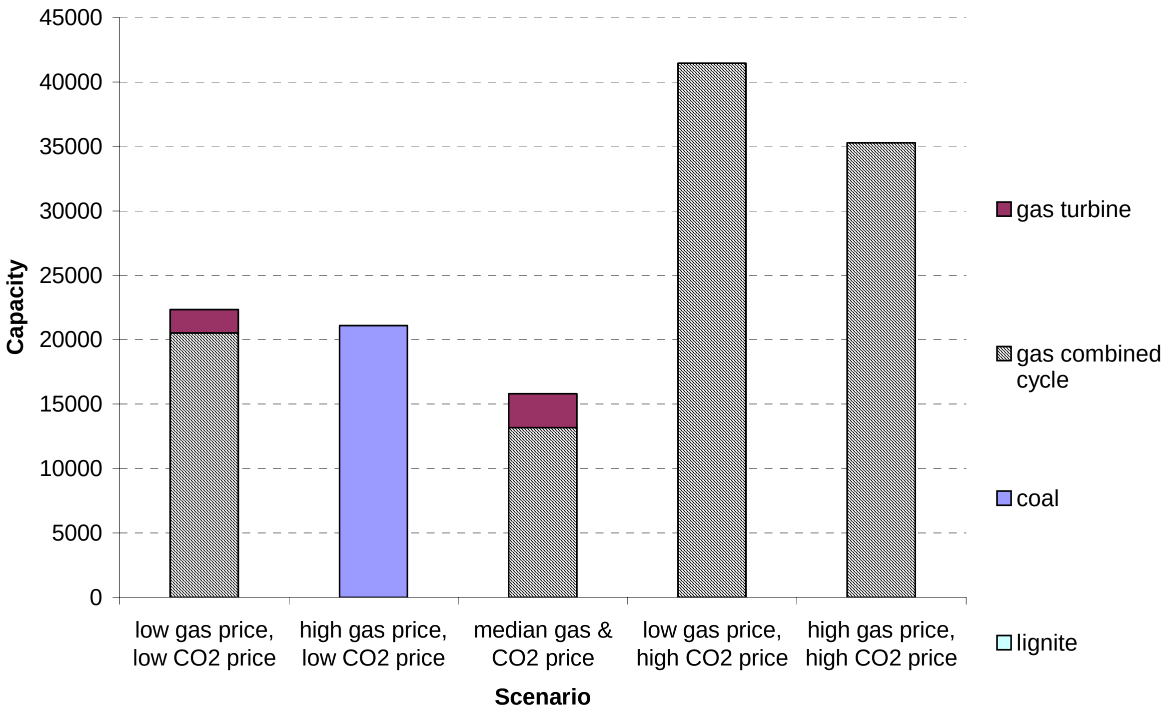
[3] Whether such a risk elimination (or rather risk transfer) provides adequate incentives for investments, is beyond the scope of the present paper.

Figure 8: Investment in different scenarios in 2010



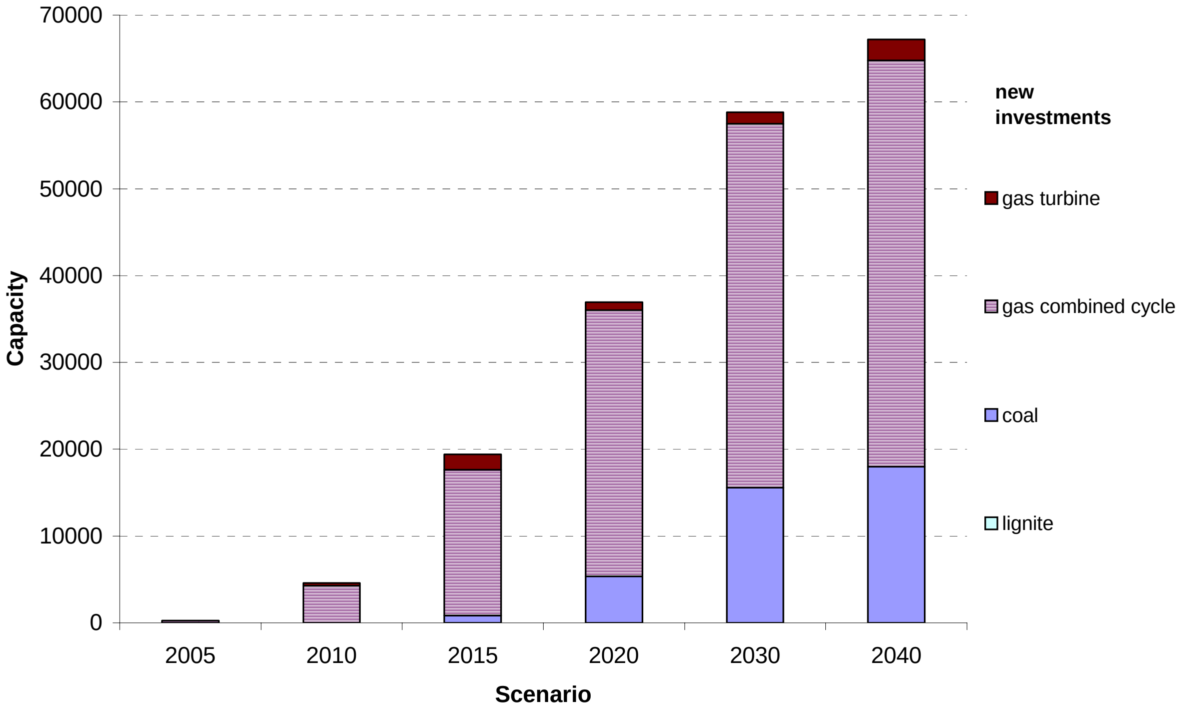
In the year 2015, considerable investments can no longer be postponed. Figure 9 gives the corresponding results. Here investment occurs in all scenarios, although at varying degrees. With high gas and low CO2 price, coal is the most advantageous fuel. But in the other scenarios shown, natural gas is clearly dominating. Lignite plants are not chosen for investment, independently of the scenario. Again high CO_2 prices are pushing towards a higher proportion of replacement investments.

Figure 9: Investment in different scenarios in 2015



The development in the subsequent years is shown in a more compact form in Figure 10. Here the probability weighted averages of the optimal stock of new power plants in the different scenarios is indicated. Gas combined cycle plants dominate throughout among the newly built plants, but under the specified price scenarios the share of coal plants gradually increases after 2020.

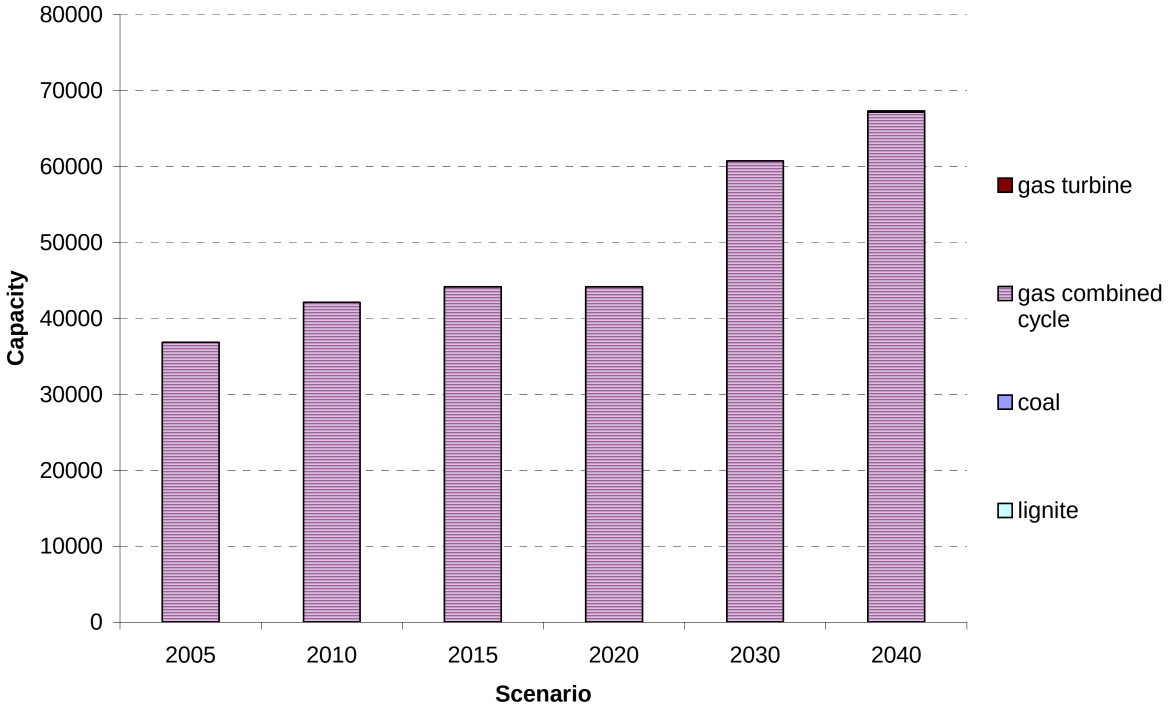
Figure 10: Development of the optimal stock of new power plants between 2005 and 2040 averaged over scenarios



Since there is no unique development path, the actual development is in fact not predictable. Also the probability weighted average is mainly intended to give an idea on the direction of the development "in the mean". But as the longer term decisions need not to be taken today, it is also not necessary to provide unique answers at this stage – instead it is important to value flexibility correctly in such a decision setting under uncertainty. That the uncertain future developments have an impact on the decisions is illustrated through Figure 11. Here the optimal stock of new power plants is shown, which is obtained if decision making under certainty is assumed. Thereby the price development corresponds to the mean of the uncertain price scenarios. Taking away the uncertainty leads to much earlier investments. Already in the year 2005, more than 30 GW of new gas combined cycle plants are installed. This is because under certainty, the future increases of CO_2 prices are anticipated. Together with the low gas prices in 2005, they lead to high investment from the early years on. Under uncertainty by contrast, investments are postponed, as discussed by Dixit and Pindyck (1994) for other examples.

As opposed to Dixit and Pindyck (1994), removing the uncertainty is not resulting in a shift towards more capital intensive technologies such as coal in the present setting. But as shown in Weber (2004), such effects may occur if nuclear plants are included as possible investment alternatives. The general result of Dixit and Pindyck and others that uncertainty will push towards flexible, less-capital intensive technologies is there clearly confirmed. But the results in Weber (2004) indicate that uncertainty does not preclude investment in capital intensive technologies, it only sets higher profitability targets.

Figure 11: Development of the optimal stock of new power plants between 2005 and 2040 under certainty



Given that uncertain CO_2 prices considerably reduce the willingness to make early investments in CO_2 abatement, the question raises, whether a CO_2 certificate trading system with highly volatile CO_2 prices is best suited to ensure that climate protection policies are rapidly followed by business. An answer to this question however requires further analysis. One might also argue that an important part of the volatility observed in the past has been a consequence of uncertainty about the political will to mitigate climate change.

In general, the results obtained with this new approach of backward induction of dynamic peak-load pricing equilibria are promising but further details have to be implemented in the methodology before it can provide reliable results on what are adequate investment strategies in the future. Notably, short term load uncertainty and longer term demand growth should also be described in detail to provide a more adequate picture of operation margins and corresponding investment opportunities in the liberalized electricity markets.

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