Schill, Wolf-Peter; Kemfert, Claudia

Working Paper
The effect of market power on electricity storage utilization: the case of pumped hydro storage in Germany

DIW Discussion Papers, No. 947

Provided in Cooperation with:
German Institute for Economic Research (DIW Berlin)

Suggested Citation: Schill, Wolf-Peter; Kemfert, Claudia (2009) : The effect of market power on electricity storage utilization: the case of pumped hydro storage in Germany, DIW Discussion Papers, No. 947, Deutsches Institut für Wirtschaftsforschung (DIW), Berlin

This Version is available at:
http://hdl.handle.net/10419/29771

Terms of use:
Documents in EconStor may be saved and copied for your personal and scholarly purposes.
You are not to copy documents for public or commercial purposes, to exhibit the documents publicly, to make them publicly available on the internet, or to distribute or otherwise use the documents in public.
If the documents have been made available under an Open Content Licence (especially Creative Commons Licences), you may exercise further usage rights as specified in the indicated licence.
Wolf-Peter Schill • Claudia Kemfert

The Effect of Market Power on Electricity Storage Utilization
The Case of Pumped Hydro Storage in Germany

Berlin, November 2009
Opinions expressed in this paper are those of the author and do not necessarily reflect views of the institute.
The effect of market power on electricity storage utilization: the case of pumped hydro storage in Germany* 

Wolf-Peter Schill†, Claudia Kemfert‡ 

November 16, 2009

Abstract

In this paper, we develop the game-theoretic electricity market model ElStorM that includes the possibility of strategic electricity storage. We apply the model to the German electricity market and analyze different realistic and counterfactual cases of strategic and non-strategic pumped hydro storage utilization by different players. We find that the utilization of storage capacities depends on the operator and its ability to exert market power both regarding storage and conventional generation capacities. The distribution of storage capacities among players also matters. A general finding is that strategic operators tend to under-utilize their storage capacities. This affects generation patterns of conventional technologies and market outcomes. Strategic under-utilization of storage capacities might also diminish their potential for renewable energy integration. Accordingly, economic regulation of existing and future storage capacities may be necessary, depending on policy objectives. We also find that the introduction of electricity storage generally increases overall welfare, while outcomes vary between different cases. Strategic storage utilization decreases consumer rent compared to non-strategic storage utilization. However, this effect is less pronounced if storage capacities are distributed among several players.

JEL classifications: Q40, Q41, L13, D43

Keywords: Electricity market modeling, pumped hydro storage, strategic storage, oligopoly, market power, Germany, ElStorM

*The authors would like to thank Frauke Braun, Steven A. Gabriel, Christian von Hirschhausen, Thure Traber and the participants of the DIW Brainy Friday seminar for helpful comments.
†Corresponding author. Graduate Center of Economic and Social Research, DIW Berlin, email: wschill@diw.de, Tel: +49 30 89789-675, Fax: +49 30 89789-113
‡Department Energy, Transportation, Environment, DIW Berlin, email: ckemfert@diw.de, Tel: +49 30 89789-663, Fax: +49 30 89789-113
1 Introduction

1.1 Motivation

Electricity storage has recently received increasing attention in the light of renewable energy integration. Since wind and solar power have fluctuating and intermittent generation characteristics, electricity storage is an obvious strategy for integrating large amounts of such renewable technologies into electricity systems. Currently, the only large-scale storage technology available is pumped hydro storage. For decades, pumped storage has been used for balancing and back-up purposes. Possible future storage technologies include compressed air storage, advanced batteries, and plug-in electric vehicles. Most electricity market models, however, do not include storage. In particular, there is little research on the issue of strategic operation of storage capacities. In this paper, we analyze the impact of introducing storage on conventional electricity generation and on market results. We also examine the difference between strategic and non-strategic storage operation. Do strategic storage operators utilize their capacities differently than competitive ones, and what is the effect on market outcomes?

For this purpose, we have developed ElStorM, an oligopolistic, game-theoretic Cournot model of the German electricity market that includes pumped hydro storage. The model allows analyzing strategic and non-strategic operation of pumped storage capacities by various players who also may have market power regarding their conventional generation capacities. We examine counterfactual and realistic cases of pumped storage operation in Germany and compare the results regarding storage utilization, generation patterns of conventional technologies and welfare. Our main finding is that not only the existence of storage capacities matters, but also their operation and distribution among players. Strategic operators utilize storage differently than non-strategic ones. In particular, they tend to under-utilize their storage capacities. It should thus neither be taken for granted that storage capacities in electricity markets with imperfect competition will be fully utilized, nor that storage will be operated in a welfare-maximizing way. This finding not only has welfare implications, but might also have consequences for the potential of storage capacities to integrate renewable energy. Depending on policy objectives, economic regulation of storage facilities might thus be necessary.

The paper is structured as follows. In the remainder of this section, we discuss relevant literature. Section 2 introduces the general structure of ElStorM, the storage mechanism, and the model implementation. Section 3 provides data and defines different cases of strategic and non-strategic storage operation. Section 4.1 analyzes the effects of introducing electricity storage on conventional generation and market prices in the simplest, counterfactual storage case. Section 4.2 compares four different cases of strategic and non-strategic storage operation regarding storage utilization, ramping of conventional generators and welfare. The last section summarizes and concludes.
1.2 Literature

In recent years, electricity market modeling has received increasing interest among energy economists, mainly spurred by electricity market liberalization in many industrialized countries. Depending on the research focus, different modeling approaches are used. Ventosa et al. (2005) provide a review of recent modeling activities. They classify models according to specific attributes like the degree of competition, time scope, uncertainty representation, interperiod links, transmission constraints and market representation. They identify three major trends: agent-based simulation models, optimization models, and (partial) equilibrium models. In the following, we focus on the third approach, since it is most suitable for analyzing market power issues.

Equilibrium models deal with simultaneous profit maximization problems of all players in the market. They are either based on Cournot or Bertrand competition (quantity or price competition), or they apply the supply function equilibrium approach (firms compete both in quantity and prices). Klemperer and Meyer (1989) show that, drawing on some assumptions, supply function equilibria are bounded by Cournot and Bertrand outcomes. Borenstein and Bushnell (1999) find that a Cournot approach fits electricity markets very well, and that Cournot oligopoly modeling is a useful tool for electricity market power analyses. Using the Californian market as an example, they find that the potential for market power is particularly high in peak load hours. Applying a game-theoretic model to the Northwestern European electricity market, Lise et al. (2006) compare the implications of different market power scenarios and find that market power exertion by large producers harms consumers. The model features environmental externalities like greenhouse gas emissions as well as two load periods in order to capture different operational characteristics of electricity generators. With a similar approach, Lise et al. (2008) analyze the impacts of additional cross-border transmission capacities on European electricity markets with the game-theoretic COMPETES model. They find that the exertion of market power increases prices in countries where the number of firms is low and where cross-border transmission capacities are scarce. They also find that dry weather increases prices in hydro-rich northern European countries. Their model features 12 different load levels that represent a whole year. Traber and Kemfert (2009b) analyze the impact of German support for renewable electricity generation on prices, emissions and profits with the game-theoretic EMELIE model that includes emissions trading. They find a substitution effect (renewable energy displaces conventional sources) and a permit price effect (renewable energy decreases the demand for emission permits) of the German feed-in tariff on carbon emissions. While electricity-related emissions in Germany decrease significantly, they hardly change on the European level. Lise and Krusemann (2008) develop a dynamic version of the Cournot approach that includes long-term investment decisions. With a recursive dynamic model named dynLEM they simulate cost composition, investments and price paths for electricity markets between 2000 and 2050, drawing on a range of assumptions about demand, elasticities and the market structure.
The models mentioned above do neither feature an hourly time representation, nor technical inter-period constraints. They rather draw on aggregated values. In contrast, a recent paper by Traber and Kemfert (2009a) introduces a game-theoretic model called ESYMMETRY which includes an hourly time resolution as well as some technical start-up constraints and related costs. The model is used for analyzing the impacts of wind power on incentives for investments in thermal power plants. The authors find that increasing wind supply decreases investment incentives for natural gas plants. Their results, however, depend on the fact that additional wind supply hardly substitutes conventional power generation.

Regarding electricity storage, there is a gap in the game-theoretic modeling literature. Ventosa et al. (2005) show that most models omit storage altogether. In particular, the issue of strategic pump storage utilization has received little attention from modelers. In contrast, there is a considerable strand of literature dealing with ‘hydro storage’ in the sense of dispatchable hydro power. Hydro reservoirs allow generators to strategically shift production capacities from one period to another. The literature dealing with this kind of ‘hydro storage’, however, mostly assumes that hydro reservoirs are replenished by natural inflows. Firms may decide strategically on hydro generation and on remaining reservoir levels, but not on replenishing their reservoirs. That is, players only decide on storage outputs, but not on inputs. Rangel (2008) provides the most recent literature review on strategic hydro scheduling in hydro-dominated electricity markets like New Zealand, Norway and some South American countries. While market power potential is usually related to exploiting temporal and geographical market separation, demand fluctuations or transmission capacity constraints, players in hydro-dominated markets may also exploit the market power potentials of hydrological conditions, reservoir levels and inflow probabilities. Rangel (2008) proposes market interventions by competition authorities and regulators in order to increase demand elasticity and decrease the concentration of hydro units.

In an early paper, Borenstein and Bushnell (1999) find that the availability level of hydro power is an important factor in determining the extent of market power. Johnsen (2001) explores this question in more detail in a stylized two-period model, where monopolists generate more electricity from hydro resources in the first period compared to the competitive solution. Thus, monopolists have less water left in the second period than competitive players. The author finds that this result fits well with Norwegian hydropower data. Garcia et al. (2001) develop an oligopoly model with dynamic Bertrand competition of hydro generators. Their simplified model framework includes two players that hold equally sized, stochastically replenishing hydro reservoirs and apply Markov strategies based on the initial state of their reservoirs. The authors find that the introduction of price caps can play a significant role in disciplining oligopolists since they limit opportunity costs of selling hydro power. Skaar (2004) builds upon this stylized theoretical framework and analyzes additional policy measures like increasing transmission capacity and demand rationing. Bushnell (2003) develops a multiperiod Cournot model of hydrothermal coordination in the Western United States.
The model includes both conventional generation and hydroelectric resources in a mixed complementarity framework. Firms strategically schedule their self-replenishing hydro resources in order to maximize profits. An important result is that strategic firms shift more hydro production towards off-peak periods than competitive ones. Kauppi and Liski (2008) apply a computational explicit dynamic model of imperfect competition to the Nordic power market. They estimate a market structure which explains the historical data of 2000-2005 and find that market power increases both reservoir levels and electricity prices. While social losses from imperfect competition in the Nordic power market are small, the potential for market power exertion increases substantially during events of extreme water shortage.

The game-theoretic Cournot model ElStorM developed in this paper increases the understanding of strategic hydro storage utilization, since it not only deals with the strategic allocation of hydro resources between periods, but also with firms’ strategic decisions on storage loading\(^1\). By providing an analysis of strategic pumped storage operation, this paper complements the body of literature that deals with the possibilities of exerting market power related to technical constraints of thermal generation, transmission capacity constraints, or locational disparities. ElStorM includes imperfect competition, an hourly time resolution, interperiod links like ramping constraints, and a representation of the whole electricity market. While the general formulation is related to Bushnell (2003) and to the more recent paper by Traber and Kemfert (2009a), ElStorM provides a substantial enlargement of the Bushnell (2003) hydro-thermal scheduling approach. Features like uncertainty, investment decisions, and transmission constraints are excluded since they would significantly add to complexity without substantially contributing to the analysis of strategic storage\(^2\). Instead, we focus on market imperfections and strategic behaviour in a Cournot setting.

2 The model ElStorM

ElStorM is a game-theoretic Cournot model of the German electricity market. Firms maximize profits by deciding on hourly electricity generation of various technologies

---

\(^1\)We focus on pumped hydro storage in this model, because it is the only large-scale storage technology that is currently available. Nonetheless, the storage mechanism is also applicable to other storage technologies. Pumped hydro storage facilities do not directly store electricity, but potential energy of water. Pumps and turbines/generators are located in a valley and connected by a pipe to an uphill reservoir or storage lake. Electricity can be ‘stored’ by pumping water into the reservoir. Later on, the water in the reservoir is used to generate electricity by running downhill again and driving the turbine/generator.

\(^2\)For an example of models with a network representation, see Neuhoff et al. (2005), who compare three Cournot models that include transmission constraints and analyze the robustness of the results. They find that within this model family, results are highly sensitive to structural and behavioural assumptions on transmission and market design. A recent example of a model that includes a representation of the European high-voltage electricity transmission network is provided by Leuthold et al. (2008).
as well as hourly pumped hydro storage loading and discharging. In doing so, firms face several technical constraints. The virtue of this model type is the representation of strategic players that exert market power. The model solution represents a Cournot-Nash equilibrium. In contrast to several earlier applications of this model type, ElStorM includes electricity storage, inter-period constraints for both conventional generation technologies and pumped storage, and an hourly time resolution. These features are essential for analyzing strategic storage operation.

Table 1 lists all model sets, indices, parameters and variables. In each time period \( t \in T \), profit-maximizing firms \( f \in F \) supply electricity by deciding on generation levels \( x_{f,i,t} \) of different technologies \( i \in I \): nuclear, lignite, hard coal, natural gas, oil, and (run-of-river) hydro power. In the following, these technologies are called ‘conventional technologies’. Firms also decide on hourly loading \( st_{in,f,t} \) and discharging \( st_{out,f,t} \) of their pumped hydro storage capacities.

While making a combined decision on hourly generation levels of conventional technologies, storage loading and storage discharging, each firm faces the following constrained maximization problem:

\[
\max_{x_{f,i,t}, st_{in,f,t}, st_{out,f,t}} \left[ \sum_{t \in T} p_t \left( \sum_{i \in I} x_{f,i,t} + st_{out,f,t} - st_{in,f,t} \right) - \sum_{t \in T} \sum_{i \in I} vgc_i \cdot x_{f,i,t} - \sum_{t \in T} vstc \cdot st_{out,f,t} \right]
\]

\[
\text{s.t. } x_{f,i,t} - x_{f,i,t-1} - \xi_{up,i} \cdot \frac{x_{f,i,t}}{x_{f,i,t-1}} \leq 0 \quad \forall f, i, t \quad (\lambda_{gencap,f,i,t}) \tag{2}
\]

\[
x_{f,i,t} - x_{f,i,t-1} - \xi_{down,i} \cdot \frac{x_{f,i,t}}{x_{f,i,t-1}} \leq 0 \quad \forall f, i, t \quad (\lambda_{rup,f,i,t}) \tag{3}
\]

\[
x_{f,i,t} - \frac{st_{out,f,t}}{st_{f,maxout}} \leq 0 \quad \forall f, t \quad (\lambda_{stoutcap,f,t}) \tag{5}
\]

\[
\sum_{\tau=1}^{t} st_{out,f,\tau} - \sum_{\tau=1}^{t-1} st_{in,f,\tau} \cdot \eta_{st} \leq 0 \quad \forall f, t \quad (\lambda_{stlo,f,t}) \tag{7}
\]

\[
\sum_{\tau=1}^{t} st_{in,f,\tau} \cdot \eta_{st} - \sum_{\tau=1}^{t-1} st_{out,f,\tau} - \frac{st_{cap}}{st_{f}} \leq 0 \quad \forall f, t \quad (\lambda_{stup,f,t}) \tag{8}
\]

\[
x_{f,i,t} \geq 0 \quad \forall f, i, t \quad (9)
\]

\[
st_{in,f,t}, st_{out,f,t} \geq 0 \quad \forall f, t \quad (10)
\]

The objective function (1) represents player f’s profit function. It includes revenues from selling electricity and costs of generation or storage in each period \( t \). Revenues
### Sets and indices

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$F$</td>
<td>Firms with $f \in F$</td>
<td></td>
</tr>
<tr>
<td>$I$</td>
<td>Generation technologies with $i \in I$</td>
<td></td>
</tr>
<tr>
<td>$T$</td>
<td>Time with time periods $t \in T$, $\tau \in T$</td>
<td>hours</td>
</tr>
</tbody>
</table>

### Parameters

| $\sigma$  | Elasticity of electricity demand      |        |
| $d_{0t}$  | Hourly reference demand               | MWh    |
| $p_{0t}$  | Hourly reference prices               | MWh    |
| $x_{\text{maxgen}}_{f}$ | Installed conventional generation capacity | MW    |
| $s\lambda_{\text{stout}}_{f}$ | Installed pumped storage generation (discharging) capacity | MW    |
| $s\lambda_{\text{stincap}}_{f}$ | Installed pumped storage loading capacity | MW    |
| $s\lambda_{\text{stst}}_{f}$ | Installed pumped storage capacity | MWh    |
| $\xi_{\text{up},i}$ | Ramping up parameter for conventional generation |        |
| $\xi_{\text{down},i}$ | Ramping down parameter for conventional generation |        |
| $v_{\text{gc}}$ | Variable generation costs | €/MWh |
| $v_{\text{vstc}}$ | Variable pumped storage costs | €/MWh |
| $v_{\text{oc}}$ | Other variable cost | €/MWh |
| $f_{p}$  | Fuel price                           | €/MWh  |
| $s_{\text{fr}}$  | Average start-up fuel requirement   | MWh/MWh |
| $s_{\text{dc}}$  | Average start-up depreciation costs | €/MWh |
| $e_{p}$  | Carbon emission price                | €/t    |
| $e_{s_{\text{c}}}$  | Specific carbon emission            | t/MWh  |
| $\eta_{\text{gen}}$  | Generation efficiency                |        |
| $\eta_{\text{st}}$  | Storage efficiency                   |        |
| $\theta_{\text{gen},f,i,t}$ | Market power parameter for generation | 0 or 1 |
| $\theta_{\text{st},f,t}$ | Market power parameter for pumped storage | 0 or 1 |

### Variables

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\Pi_{f}$</td>
<td>Profit of firm $f$</td>
<td>€</td>
</tr>
<tr>
<td>$p_{t}$</td>
<td>Price of period $t$</td>
<td>€/MWh</td>
</tr>
<tr>
<td>$x_{f,i,t}$</td>
<td>Generation of firm $f$ with technology $i$ in period $t$</td>
<td>MWh</td>
</tr>
<tr>
<td>$X_{t}$</td>
<td>Total supply in period $t$</td>
<td>MWh</td>
</tr>
<tr>
<td>$\text{stout}_{f,t}$</td>
<td>Electricity generation in period $t$ of firm $f$ from pumped storage</td>
<td>MWh</td>
</tr>
<tr>
<td>$\text{stin}_{f,t}$</td>
<td>Pumped storage loading in period $t$ of firm $f$</td>
<td>MWh</td>
</tr>
<tr>
<td>$\lambda_{\text{gencap},f,i,t}$</td>
<td>Shadow price of conventional generation capacity constraint</td>
<td>€/MWh</td>
</tr>
<tr>
<td>$\lambda_{\text{rup},f,i,t}$</td>
<td>Shadow price of ramping up constraint</td>
<td>€/MWh</td>
</tr>
<tr>
<td>$\lambda_{\text{rdo},f,i,t}$</td>
<td>Shadow price of ramping down constraint</td>
<td>€/MWh</td>
</tr>
<tr>
<td>$\lambda_{\text{stoutcap},f,t}$</td>
<td>Shadow price of storage generation capacity constraint</td>
<td>€/MWh</td>
</tr>
<tr>
<td>$\lambda_{\text{stinincap},f,t}$</td>
<td>Shadow price of storage loading capacity constraint</td>
<td>€/MWh</td>
</tr>
<tr>
<td>$\lambda_{\text{stup}}$</td>
<td>Shadow price of upper storage capacity constraint</td>
<td>€/MWh</td>
</tr>
<tr>
<td>$\lambda_{\text{stlo}}$</td>
<td>Shadow price of lower storage capacity constraint</td>
<td>€/MWh</td>
</tr>
<tr>
<td>$\vartheta_{i,t}$</td>
<td>Market share of firm $f$ - conventional generation</td>
<td></td>
</tr>
<tr>
<td>$\vartheta_{\text{fdis},t}$</td>
<td>Storage market share of firm $f$ - discharging</td>
<td></td>
</tr>
<tr>
<td>$\vartheta_{\text{fload},t}$</td>
<td>Storage market share of firm $f$ - loading</td>
<td></td>
</tr>
<tr>
<td>$\text{crent}_{t}$</td>
<td>Consumer rent of period $t$</td>
<td>€</td>
</tr>
<tr>
<td>$\text{prent}_{f,t}$</td>
<td>Producer rent of firm $f$ in period $t$</td>
<td>€</td>
</tr>
</tbody>
</table>

Table 1: Sets, indices, parameters and variables
include sales of electricity from conventional generation technologies \( p_t \cdot \sum_{i \in I} f_{i,t} \) and from pumped storage \( p_t \cdot stout_{f,t} \). As usual in electricity markets, there is one market price independent of the generation technology. Note that in the case of market power, the market price \( p_t \) not only depends on a firm’s decisions on conventional output, but also on storage loading and discharging. On the cost side, equation (1) includes technology-specific variable generation costs \( v_{gc_i} \). As shown in equation (11), \( v_{gc_i} \) depend on fuel prices \( f_{pi} \), emission prices \( ep \), specific emissions \( se_i \), technology-specific generation efficiency \( \eta_i \) and other variable costs \( ovc_i \). Variable generation costs also include a lump-sum premium for start-up costs: the terms \( sfr_i \) and \( sdc_i \) describe average start-up fuel requirements and depreciation costs that are positive for hard coal, gas and oil plants. They have been estimated under the assumption that a quarter of the installed capacity of these technologies has to be started up from zero output to 100% each day, given average daily full load hours. The profit function also includes variable costs of storage operation \( vstc \), reflecting staff and maintenance costs. These costs are assumed to be constant for every unit of electricity generated and assigned to storage loading. Equation (1) also includes costs of storage \( \sum_{t \in T} p_t \cdot stout_{f,t} \), reflecting the fact that electricity stored at period \( t \) had to be bought or could have been sold on the market at the price \( p_t \). Thus, firms face costs equal to the market price \( p_t \) for each unit of electricity stored at time \( t \).

\[
v_{gc_i} = \frac{f_{pi} + ep \cdot se_i}{\eta_i} + ovc_i + (f_{pi} + ep \cdot se_i) \cdot sfr_i + sdc_i \quad \forall i \quad (11)
\]

Condition (2) represents the firm’s maximum generation capacity restrictions. For each conventional technology \( i \), a firm’s actual power generation cannot exceed its installed capacity. Conditions (3) and (4) represent inter-period constraints. (3) is a ‘ramping up’ restriction: between two hours, electricity generation of a particular technology can only be increased or ‘ramped up’ to a certain degree, depending on a technology-specific parameter \( \xi_{up,i} \) and the total installed capacity. \( \xi_{up,i} \) has values between 0 and 1. While \( \xi_{up,i} \) is relatively small for inflexible nuclear power, it takes the value 1 for flexible gas plants (see Table 3). Likewise, condition (4) represents technology-specific ‘ramping down’ restrictions. In contrast to Traber and Kemfert (2009a), we include not only restrictions on ramping up, but also on ramping down.

Conditions (5) to (8) concern pumped hydro storage. Condition (5) resembles (2). It states that the amount of electricity generated from pumped storage cannot exceed the installed generating capacity in any period \( t \). Likewise, condition (6) constrains
the amount of electricity that can be loaded into the storage facility at any period \( t \), i.e. considers limited pumping capacities. Conditions (7) and (8) represent restrictions on energy storage capacities, i.e. on available reservoirs. Condition (7) ensures that generation from storage stops once the reservoirs are empty. The amount of electricity generated from pumped hydro storage in any period \( t \) thus cannot exceed the net of previous inflows and outflows. Condition (8) represents the upper storage capacity constraint. For each period \( t \), the amount that can be loaded into the storage facility cannot exceed total reservoir capacities, given the history of inflows and outflows up to this period. This restriction makes sure that reservoirs never overflow. Conditions (7) and (8) include efficiency losses: since pumped storage facilities are not perfectly efficient, only a share \( \eta_{st} \) of stored electricity can be recovered. There is no ramping constraint for pumped storage, since it is by design a very flexible technology. Conditions (9) and (10) ensure non-negativity of the variables \( x_{f,i,t} \), \( stin_{f,t} \) and \( stout_{f,t} \).

The market clearing condition (12) is required to ensure that supply equals demand in every period. As in other models\(^7\), demand is represented by an iso-elastic function, drawing on exogenous reference demands \( d_0 \) and prices \( p_0 \). \( \sigma \) represents price elastiticy of demand\(^8\). \( X_t \) represents total electricity supply, consisting of the total amount of electricity generated by all firms and technologies, plus generation from pumped storage, minus storage loading, as shown in (13).

\[
X_t = d_0 t \left( \frac{p_t}{p_0} \right)^{-\sigma} \quad \forall t \tag{12}
\]

\[
X_t = \sum_{f \in F} \sum_{i \in I} x_{f,i,t} + \sum_{f \in F} \left[ stout_{f,t} - stin_{f,t} \right] \quad \forall t \tag{13}
\]

We re-formulate the optimization problem (1 - 10) as a nonlinear mixed complementarity problem (MCP), which allows analyzing market power issues in a partial equilibrium setting. The definition of a MCP, its application to economic analyses and its implementation in GAMS is described by Rutherford (1995) and Ferris and Munson (2000). Consisting of a square system of equations, a MCP problem is a generalization of special cases like nonlinear equation systems or complementarity problems. Mixed complementarity problems incorporate both equalities and inequalities. Thus, MCPs can be used for modeling Karush-Kuhn-Tucker (KKT) optimality conditions. With a convex underlying optimization problem, the KKT approach leads to a globally optimal solution. We combine the market clearing condition (12) with (13), solve for \( p_t \) and insert it into (1). We then and derive the KKT optimality conditions from the optimization problem. This results in equations (14-24), which form our mixed complementarity problem:

\(^7\)For example, Borenstein and Bushnell (1999) or Traber and Kemfert (2009b)

\(^8\)It is assumed that elasticity neither depends on the time period nor on the demand level. Time-dependent or demand-dependent elasticities might be more realistic, but would complicate our analysis of strategic storage.
\begin{align*}
0 & \leq vgc_i + \lambda_{\text{gencap},f,i,t} + \lambda_{\text{rup},f,i,t} - \lambda_{\text{rup},f,i,t+1} - \lambda_{\text{rdo},f,i,t} + \lambda_{\text{rdo},f,i,t+1} \\
& \quad - p_t \left( 1 - \frac{\vartheta_{f,i,t} \cdot \theta_{\text{gen},f,i,t} + \vartheta_{\text{rup},f,i,t} \cdot \theta_{\text{gencap},f,i,t} - \vartheta_{\text{rup},f,i,t} \cdot \theta_{\text{rup},f,i,t}}{\sigma} \right) \\
& \quad \perp x_{f,i,t} \geq 0 \quad \forall f, i, t \quad (14) \\
0 & \leq \lambda_{\text{stincap},f,t} + \lambda_{\text{stoutcap},f,t} + \sum_{\tau=t}^{T} \lambda_{\text{stlo},f,\tau} - \sum_{\tau=t}^{T-1} \lambda_{\text{stup},f,\tau+1} \\
& \quad - p_t \left( 1 - \frac{\sum_{i \in I} \vartheta_{f,i,t} \cdot \theta_{\text{gen},f,i,t} + \vartheta_{\text{out},f,t} \cdot \theta_{\text{stcap},f,t} - \vartheta_{\text{in},f,t} \cdot \theta_{\text{stcap},f,t}}{\sigma} \right) \\
& \quad \perp \lambda_{\text{stincap},f,t} \geq 0 \quad \forall f, t \quad (15) \\
0 & \leq -x_{f,i,t} + x_{\text{maxgen}}_{f,i,t} \\
0 & \leq -x_{f,i,t} + x_{f,i,t-1} + \xi_{\text{up},i} \cdot x_{\text{maxgen}}_{f,i} \\
0 & \leq -x_{f,i,t-1} + x_{f,i,t} + \xi_{\text{down},i} \cdot x_{\text{maxgen}}_{f,i} \\
0 & \leq -\text{stout}_{f,t} + \text{stmaxout}_{f,t} \\
0 & \leq -\text{stincap}_{f,t} + \text{stmaxin}_{f,t} \\
0 & \leq -\sum_{\tau=1}^{t} \text{stout}_{f,\tau} + \sum_{i=1}^{t-1} \text{stincap}_{f,\tau} \cdot \eta_{\text{st}} \\
0 & \leq -\sum_{\tau=1}^{t} \text{stincap}_{f,\tau} \cdot \eta_{\text{st}} + \sum_{\tau=1}^{t-1} \text{stout}_{f,\tau} + \text{stmaxcap}_{f,t} \\
0 & = X_t - d_0 \left( \frac{p_t}{p_0_t} \right)^{-\sigma} \quad , \quad (p_t) \quad \text{free} \quad \forall t \quad (24)
\end{align*}
Equations (14-24) include market shares $\vartheta_{f,i,t}$, $\vartheta_{out}^{f,t}$ and $\vartheta_{in}^{f,t}$ as defined in (25-27). These market shares indicate a firm’s market power regarding generation and storage. They also include market power parameters $\theta_{gen,f,i,t}$ and $\theta_{st,f,t}$. Exogenously assigning the values 0 or 1 allows ‘switching’ off and on market power for specific firms both regarding generation and storage operation.

\[
\vartheta_{f,i,t} = \frac{x_{f,i,t}}{X_t} \quad \forall f, i, t \tag{25}
\]

\[
\vartheta_{out}^{f,t} = \frac{stout_{f,t}}{X_t} \quad \forall f, t \tag{26}
\]

\[
\vartheta_{in}^{f,t} = \frac{stin_{f,t}}{X_t} \quad \forall f, i, t \tag{27}
\]

Conditions (14-16) may be interpreted as follows. Equation (14) includes a standard Cournot result: In case of positive market shares $\vartheta_{f,i,t}$ for conventional generation technologies, market prices exceed the sum of marginal costs and shadow prices. The larger the market share of a firm, the larger its market power and its ability to raise prices beyond marginal costs. While this is a common result of Cournot models, the inclusion of storage-related market shares $\vartheta_{out}^{f,t}$ and $\vartheta_{in}^{f,t}$ is a new contribution to the literature. Positive market shares regarding storage output $\vartheta_{out}^{f,t}$ have the same effect as positive ‘conventional’ market shares: larger $\vartheta_{out}^{f,t}$ increase a firm’s ability to raise prices beyond marginal costs. The market share of storage input $\vartheta_{in}^{f,t}$, however, enters with a negative sign. Keep in mind that a firm has opportunity costs for electricity that is stored and not sold at period $t$. Thus, higher prices imply higher storage loading costs. The higher the market share $\vartheta_{in}^{f,t}$ of a player, the larger its interest in low prices in periods of storage loading. Strategically operated storage capacities thus mitigate a player’s incentives to raise prices by withholding conventional capacities during periods of storage loading. In contrast, in such periods strategic players with large storage-loading market shares $\vartheta_{in}^{f,t}$ may exert market power with their conventional capacities in order to drive down prices.

Condition (15) on storage outputs may be interpreted in a similar way. The market price exceeds storage-related marginal costs in the case of positive storage-related market power $\vartheta_{out}^{f,t}$. If a player also holds conventional generation capacities, its cumulative market shares $\sum_{i \in I} \vartheta_{f,i,t}$ of these technologies allow raising prices. Again, high storage loading market shares decrease a strategic player’s incentives to raise prices, since $\vartheta_{in}^{f,t}$ enters with a negative sign.

Equations (14-24) form an MCP equation system consisting of more than 60,000 variables and equations. It is implemented in the General Algebraic Modeling System (GAMS), including real data on generation capacities, costs and demand from the German electricity market. The problem is solved with the solver PATH, which represents a generalization of Newton’s method, including a path search (cp. Ferris and
After solving the complementarity problem, consumer rent \( \text{crent}_t \) and producer rent \( \text{pren}_t \) are calculated. Consumer rent of period \( t \) is determined according to equation \((28)\) by integrating the demand function from 0 up to the actual quantity\(^9\) and subtracting the amount actually paid. Producer rent for each player is calculated according to equation \((29)\) by summing up revenues and subtracting costs.

\[
\text{crent}_t = \int_0^{X_t} p_0 t \left( \frac{x}{d_0 t} \right)^{-\frac{1}{\sigma}} dx - p_t X_t \quad \forall t \tag{28}
\]

\[
\text{pren}_{f,t} = \sum_{i \in I} x_{f,i,t} \cdot (p_t - v_{gc_i}) + \text{stout}_{f,t} \cdot (p_t - v_{stc}) - \text{stin}_{f,t} \cdot p_t \quad \forall t \tag{29}
\]

### 3 Data and scenarios

The data used in the model represents the German electricity market. Regarding reference demand \( d_0 \) and reference prices \( p_0 \), hourly EEX data\(^{10}\) is used for one characteristic week in October 2008 between Monday, 13 and Sunday, 19.

We assume a short-term elasticity of demand of \( \sigma = 0.35 \). Calibrating the model with this value provides a reasonable replication of the reference data and is also in line with earlier models\(^{11}\). For reasons of simplicity and traceability, \( \sigma \) is assumed to be time-invariant.

Five players are included in the model: E.ON, RWE, Vattenfall and EnBW are the largest strategic market players. Together they hold around 81% of the German generation capacity (cp. Table 2). In addition, a competitive fringe player named ‘Fringe’ is included, which is assigned the remaining generation capacity. Table 2 shows installed capacities of conventional electricity generation technologies for these five players. ‘Natural gas’ includes natural gas combined cycle, steam and gas turbines. ‘Hydro’ includes run-of-river plants and other hydroelectric plants, but excludes pumped storage capacities. Data on generation capacities is derived from Traber and Kemfert\( (2009a)\).

Since not all plants are available at a given time due to maintenance and outages, the installed capacities listed in Table 2 are not fully utilized in the numerical simulation. Average availabilities are calculated from EEX data\(^{12}\). Moreover, the capacities of

---

\(^9\)In the numerical application, \( x = 1 \) is used as the lower integration limit for reasons of solvability. \( x = 0 \) would result in a division by zero. Other non-zero values are possible, as well. However, the choice of the lower integration limit is irrelevant since we do not look at absolute levels of consumer rent, but only at rent changes between different scenarios.

\(^{10}\)http://www.eex.com/en/Market Data/Trading Data/Power

\(^{11}\)For example, compare Borenstein and Bushnell (1999) or Traber and Kemfert (2009b)

\(^{12}\)http://www.eex.com/en/Transparency/Powder plant information/Data/Overview
Table 2: Installed conventional capacities in MW

<table>
<thead>
<tr>
<th>Technology</th>
<th>EnBW</th>
<th>E.ON</th>
<th>RWE</th>
<th>Vattenfall</th>
<th>Fringe</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>4,019</td>
<td>7,639</td>
<td>3,536</td>
<td>1,418</td>
<td>957</td>
</tr>
<tr>
<td>Lignite</td>
<td>404</td>
<td>1,320</td>
<td>8,614</td>
<td>7,303</td>
<td>409</td>
</tr>
<tr>
<td>Hard coal</td>
<td>2,674</td>
<td>9,933</td>
<td>4,453</td>
<td>1,667</td>
<td>6,136</td>
</tr>
<tr>
<td>Natural gas</td>
<td>1,044</td>
<td>3,871</td>
<td>2,982</td>
<td>2,103</td>
<td>6,548</td>
</tr>
<tr>
<td>Oil</td>
<td>440</td>
<td>1,483</td>
<td>21</td>
<td>646</td>
<td>541</td>
</tr>
<tr>
<td>Hydro</td>
<td>427</td>
<td>1,507</td>
<td>638</td>
<td>0</td>
<td>893</td>
</tr>
</tbody>
</table>

Traber and Kemfert (2009a) do not exactly match the registered capacities at EEX. For reasons of consistency (all reference price and demand data are derived from EEX), the capacities listed in Table 2 are adjusted in order to match capacities registered at EEX. Table 3 lists the combined ‘Availability and adjustment’ factors. The table also includes other technical parameters like ramping up and down parameters\(^\text{13}\), costs, emission and efficiency parameters. Data sources include Traber and Kemfert (2009a), dena (2005), EEX, UCTE, International Energy Agency and own calculations. In addition, we assume a carbon emission price \(e_p\) of \(\euro20/t\).

<table>
<thead>
<tr>
<th>Technology</th>
<th>Nuclear</th>
<th>Lignite</th>
<th>H. Coal</th>
<th>N. Gas</th>
<th>Oil</th>
<th>Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>Availability and adjustment</td>
<td>87%</td>
<td>92%</td>
<td>59%</td>
<td>62%</td>
<td>55%</td>
<td>79%</td>
</tr>
<tr>
<td>Ramping param. (\xi_{\text{up},i} = \xi_{\text{down},i})</td>
<td>0.04</td>
<td>0.04</td>
<td>0.25</td>
<td>0.30</td>
<td>0.80</td>
<td>0.15</td>
</tr>
<tr>
<td>Fuel prices (f_p) in (\euro/MWh)</td>
<td>2.1</td>
<td>4.5</td>
<td>7.2</td>
<td>21.7</td>
<td>17.2</td>
<td>0</td>
</tr>
<tr>
<td>Spec. carbon emission (s_e) in t/MWh</td>
<td>0</td>
<td>0.40</td>
<td>0.34</td>
<td>0.19</td>
<td>0.28</td>
<td>0</td>
</tr>
<tr>
<td>Generation efficiency (\eta)</td>
<td>0.33</td>
<td>0.37</td>
<td>0.38</td>
<td>0.45</td>
<td>0.35</td>
<td>1.00</td>
</tr>
<tr>
<td>Other var. costs (ovc) in (\euro/MWh)</td>
<td>0.7</td>
<td>2.6</td>
<td>2.0</td>
<td>1.4</td>
<td>1.5</td>
<td>2.6</td>
</tr>
<tr>
<td>Start-up fuel req. (sfr) in MWh/MWh</td>
<td>0</td>
<td>0</td>
<td>2.2</td>
<td>1.6</td>
<td>1.6</td>
<td>0</td>
</tr>
<tr>
<td>Start-up depreci. costs (sfr) in (\euro/MWh)</td>
<td>0</td>
<td>0</td>
<td>1.7</td>
<td>4.6</td>
<td>4.6</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 3: Parameters for conventional generation technologies

The total pumped hydro storage generation capacity currently installed in Germany amounts to around 6.4 GW. Table 4 shows how the total capacity is distributed among different players. Data sources include company reports and other publications\(^\text{14}\). The literature survey showed that most pumped storage plants have roughly the same capacities for loading and discharging. Thus, we assume \(st_f^{\text{maxout}} = st_f^{\text{maxin}}\). Note that these values refer to the power of turbines and pumps, and are accordingly measured in MW. In contrast, the installed storage capacities \(st_f^{\text{cap}}\) refer to the volumes of the

\(^{13}\)We assume equal parameters for ramping up and down, i.e. \(\xi_{\text{up},i} = \xi_{\text{down},i}\).

\(^{14}\)Sources include Tiedemann et al. (2008) and company information provided by EnBW, E.ON, RWE, Vattenfall and Schluchseewerk. In addition to domestic capacities listed in Table 4, German grid operators also utilize pumped hydro storage plants in neighbouring countries to some extent. For reasons of traceability and consistency, only domestic capacities have been included. Note that ‘Schluchseewerk’ is a large German pumped hydro storage operator, which is owned by EnBW and RWE with 50% each. An interview with a company representative showed that 50% of the company’s storage capacities are operated for EnBW and another 50% for RWE. Accordingly, the total ‘Schluchseewerk’ capacities have been assigned to EnBW and RWE with 50% each.
storage lakes and are thus measured in MWh. However, we assume that only 80% of the capacities shown in Table 4 are available at a given time. On the one hand, this is due to outages and maintenance, which leads to average pump storage availabilities of about 95%. On the other, it reflects the fact that around 15% of total capacities are reserved for backup and black start purposes\textsuperscript{15}. Furthermore, we assume variable storage operation costs $v_{\text{pumpstor}}$ of € 1 per MWh generated from pumped storage and average storage efficiency of $\eta_{\text{pumpstor}} = 0.75$\textsuperscript{16}. That is, for each MWh that is loaded into pumped storage facilities, 0.75 MWh can be retrieved again.

\begin{table}[h]
\begin{tabular}{|l|c|c|c|c|c|}
\hline
 & EnBW & E.ON & RWE & Vattenfall & Fringe \\
\hline
Storage generation capacity $st_{\text{gen}}$ in MW & 1,006 & 1,017 & 1,023 & 2,893 & 456 \\
\hline
Storage loading capacity $st_{\text{load}}$ in MW & 1,006 & 1,017 & 1,023 & 2,893 & 456 \\
\hline
Installed storage capacity $st_{\text{cap}}$ in MWh & 7,200 & 6,790 & 6,959 & 17,141 & 2,202 \\
\hline
\end{tabular}
\caption{Storage capacities}
\end{table}

Five different cases are analyzed. First, we exclude pumped storage altogether in the nostor case for reasons of comparison. Then, the total German pumped hydro storage capacity is either assigned to the Fringe player, or to the largest player E.ON. We assume that the Fringe operates pumps storage in a non-strategic way, just like its other generation assets ($\theta_{\text{st,Fringe},t} = 0 \ \forall t$ and $\theta_{\text{gen,Fringe},i,t} = 0 \ \forall i, t$). In contrast, we assume that E.ON operates its storage capacities as well as its conventional generation assets in a strategic way ($\theta_{\text{st,E.ON},t} = 1 \ \forall t$ and $\theta_{\text{gen,E.ON},i,t} = 1 \ \forall i, t$). These two simple, counterfactual cases provide an illustrative example for analyzing the basic properties of the storage mechanism and the general effects of strategic and non-strategic storage operation. We name them counterstor-Fringecomp and counterstor-E.ONstrat, respectively. After that, we look at two cases in which the pumped storage capacities are assigned to the players according to real data from the German electricity market (compare Table 4). In the realstor-allcomp case, all players operate their storage capacities in a non-strategic way ($\theta_{\text{st},i,t} = 0 \ \forall i, t$). In contrast, in the realstor-4strat case, the four largest players operate their storage capacities strategically, just like their conventional generation capacities ($\theta_{\text{st,EnBW},t} = \theta_{\text{st,E.ON},t} = \theta_{\text{st,RWE},t} = \theta_{\text{st,Vattenfall},t} = 0 \ \forall t$). Analyzing the latter two cases is more complex than analyzing the counterfactual ones, but leads to a better understanding of the situation on the German electricity market. In the following, the five cases are summed up:

1. nostor: The market result without storage capacities
2. counterstor-Fringecomp: Total storage capacity is counterfactually assigned to Fringe, which operates storage competitively
3. counterstor-E.ONstrat: Total storage capacity is counterfactually assigned to E.ON, which operates storage strategically

\textsuperscript{15}These estimations are based on interviews with industry representatives.
\textsuperscript{16}Compare Tiedemann et al. (2008)
4. **realstor-allcomp**: Realistic storage capacities, all players operate storage competitively

5. **realstor-4strat**: Realistic storage capacities, largest four players operate storage strategically

### 4 Results

#### 4.1 General effects of introducing storage

First, we look at the simplest case **counterstor-Fringecomp** where the total German pumped storage capacity is assigned to the Fringe firm, which operates it in a non-strategic way, that is \( \theta_{st,\text{Fringe},t} = 0 \) \( \forall t \). Figure 1 shows storage loading and discharging in the context of total electricity generation.

![Figure 1: Total generation in the counterstor-Fringecomp case](image)

Starting on a Monday, the different consumption levels of working days and the weekend are visible. A characteristic daily double peak - around noon and in the evening - is also observable for most days. Nuclear and run-of-river hydro plants (in contrast to hydro pumped storage) are providing base load due to technology-specific ramping restrictions (in the case of nuclear) and low marginal costs (both nuclear and hydro). Lignite and hard coal provide medium load. It is obvious that ramping restrictions are more tight for lignite than for hard coal. Gas and oil provide peak load. Overall, Figure 1 indicates that the model provides a reasonable representation of the German electricity generation market.
As for storage, we observe a characteristic pattern of storage loading at nighttime (when prices are low) and discharging at the daily peak load hours (when prices are high). This result corresponds well with the operational characteristics expected from real pumped storage facilities. Comparing counterstor-Fringecomp to nostor, we find that pumped hydro output mainly substitutes peak load gas and oil generation. Figure 2 illustrates storage operation in the respective week in more detail. We can see that pumped storage facilities always need to be loaded before they can be discharged. The characteristic pattern of nighttime storage loading and peak-hour discharging is clearly visible. Some sensitivity analyses show that assuming lower storage efficiencies or higher storage costs results in similar storage patterns, but in lower overall storage utilization.

![Storage loading and discharging - counterstor-Fringecomp](image)

**Figure 2**: Storage loading and discharging in the counterstor-Fringecomp case

Comparing ramping restrictions between the cases with and without storage, we find that introducing pumped storage has a smoothing effect on conventional generation - in particular, regarding hard coal and lignite. Introducing storage substantially decreases the number of binding ramping restrictions (i.e. positive shadow prices $\lambda_{rup,f,i,t}$ and $\lambda_{rdo,f,i,t}$) in the 168 periods from 426 in the nostor case to 301 in the counterstor-Fringecomp case\(^{17}\). This is an important storage characteristic in the context of renewable electricity integration, which in general increases ramping requirements.

The introduction of pumped storage also has a smoothing effect on market prices.\(^{17}\)

\(^{17}\)Note that this results holds even though ramping-related costs are not included in the model.
Storage allows increasing the generation of cheap base-load technologies and accordingly decreasing the generation of expensive peak load power. Since the market price is determined by the most expensive generation technology, storage utilization accordingly decreases peak prices and only moderately increases off-peak prices. Figure 3 illustrates this result by comparing prices in the nostor and counterstor-Fringecomp cases. In the respective week, the price smoothing effect of introducing storage leads to consumer benefits of about \( € 7 \text{ million} \) and to producer losses of about \( € 3.5 \text{ million} \), i.e. a net welfare gain.

![Prices in the nostor and counterstor-Fringecomp cases](image)

**Figure 3:** Comparison of prices: nostor and counterstor-Fringecomp

### 4.2 Different cases of strategic and non-strategic storage operation

In this section we compare the model results of the cases counterstor-Fringecomp, counterstor-E.ONstrat, realstor-allcomp, and realstor-4strat to the nostor case without storage. The major finding is that storage utilization and market outcomes depend on the storage operator and on its ability for exerting market power both regarding storage and conventional generation capacities.

Figure 4 shows that total storage output over the 168 periods varies substantially between the cases. In both the counterfactual and the realistic scenarios, storage utilization is higher in the case of non-strategic storage operation. We find a particularly large difference in the counterfactual scenarios. In the counterstor-Fringecomp case, where the total storage capacity is operated by the Fringe player in a non-strategic way (just like Fringe’s other generation capacities), total storage output is around 130 GWh. In contrast, in the counterstor-E.ONstrat case, where the total storage
capacity is strategically operated by E.ON (and E.ON also strategically operates its other generation capacities), total storage output amounts to less than 8 GWh. If storage is assigned to the players according to real data, non-strategic storage operation results in total storage output of about 173 GWh (realstor-allcomp), while strategic operation of the four largest players results in total storage output of only 135 GWh (realstor-4strat). These results show that storage utilization is highest if storage is distributed among several players and operated in a non-strategic way. This is a relevant finding in the context of renewable electricity integration.

Regarding the impact of storage on conventional generation technologies, we find that storage generally decreases the number of binding ramping restrictions, i.e. smoothes conventional generation. Compared to nostor, which has 426 binding ramping restrictions, we find 301 binding ramping restrictions in the non-strategic counterstor-Fringe case, but 432 in the strategic counterstor-E.ONstrat case, where much less storage is used. There are 284 binding ramping restrictions for realstor-allcomp and 312 for realstor-4strat, respectively. That is, ramping restrictions are generally lower in the non-strategic cases, where storage utilization is higher\(^{18}\). Table 5 in the Appendix provides more details on storage utilization and ramping restrictions in the different cases.

As for welfare, we find that the introduction of storage increases welfare in all cases except counterstor-E.ONstrat. Figure 5 illustrates absolute changes in producer welfare.

\(^{18}\)Note that ramping as such does not involve any costs in our model. Including a bottom-up representation of ramping-related costs, e.g. costs of thermal inefficiencies or additional fuel requirements, results might change.
rent, consumer rent, and total welfare of the four scenarios compared to the nostor case. Table 6 in the Appendix provides more details on welfare results and on relative changes in producer rent.

Comparing the cases with counterfactual storage assignment (the two cases on the left-hand side of Figure 5), we find that consumers are much better off in the counterstor-Fringecomp case, where storage utilization is high, compared to the counterstor-E.ONstrat case, where the storage capacity is massively under-utilized. The reason for this result is the price-smoothing effect of storage that was discussed in Section 4.1. Pumped storage allows using a larger amount of cheap base-load technologies, which results in substantially lower peak prices. While consumers benefit from this effect, producers lose. Therefore, E.ON massively under-utilizes its storage capacity in the counterstor-E.ONstrat case in order not to smooth prices too much. E.ON’s producer rent in counterstor-E.ONstrat is slightly higher than in the case without storage and much higher (about € 2.1 million) than in counterstor-Fringecomp. All other producers free-ride on E.ON’s price-driving strategy while consumers lose. In contrast, only the Fringe player’s producer rent increases in counterstor-Fringecomp compared to nostor, while the four large players suffer losses. Introducing storage leads to a substantial overall welfare gain in the non-strategic counterstor-Fringecomp case, but to a small net welfare loss in the strategic counterstor-E.ONstrat case.

In both cases with realistic assignment of storage capacities, realstor-allcomp and realstor-4strat (the two cases on the right-hand side of Figure 5), overall welfare increases compared to nostor. Consumers benefit from introducing storage in both cases, while producers lose. Although less pronounced than in the counterfactual cases, we find again that consumers are better off with non-strategic storage operation, since it leads to higher storage utilization. As expected, producers are better off in the
strategic case, although they still suffer losses compared to the nostor case. Above, we have shown that the producer rent increases compared to nostor if a single player strategically operates the whole storage capacity of the market. In contrast, strategic storage operators suffer losses in the realstor-4strat case, where the storage capacity is distributed among players, compared to nostor. The reason is that withholding storage capacity is difficult for a single player in this setting, since other players may jump in. Total storage utilization is thus much higher in realstor-4strat than in counterstor-E.ONstrat. This results in smoother prices, which benefits consumers and harms producers. Another interesting finding of the realstor-allcomp case is that every single player suffers losses compared to nostor. All players would be better off if they agreed not to utilize their storage capacities at all. However, the players have an incentive to deviate from this point and to utilize some storage capacity in order to make additional profits. This situation resembles the classic prisoner’s dilemma.

5 Summary and conclusion

We have developed ElStorM, a game-theoretic, computational Cournot model of the German electricity market that includes pumped hydro storage. Drawing on real data of the German electricity market, and using reference demand and price data of a characteristic week in October 2009, we have analyzed different cases of strategic and non-strategic pumped storage utilization by players that may also have market power regarding their conventional generation capacities.

First, we find that the storage mechanism developed in this paper results in realistic patterns of storage loading and discharging which are comparable to real pumped storage operation cycles. Introducing storage generally smooths both conventional generation and market prices, and increases overall welfare. Our main finding, however, is that not only the amount of available storage capacities matters, but also storage operation. The utilization of storage capacities depends on a player’s market power regarding both storage capacities and conventional generation, and also on the distribution of storage capacities among players. In turn, varying degrees of storage utilization have an impact on conventional electricity generation and welfare.

Analyzing the effects of strategic and non-strategic storage utilization, it is useful to look separately at the results regarding storage utilization and welfare. We find that the utilization of a given storage capacity heavily depends on the ability of a player to operate it in a strategic or non-strategic way. A player’s market power regarding its conventional generation capacities and the distribution of storage capacities among players also matter. In the counterfactual cases, where the total storage capacity is assigned to only one player, storage utilization is much higher in the case of non-strategic storage operation by the Fringe Player (counterstor-Fringecomp) compared to strategic operation by the largest player E.ON (counterstor-E.ONstrat). With a realistic
assignment of storage capacities to the players according to actual German data, we also find that storage utilization is higher in the non-strategic case (realstor-allcomp) compared to strategic storage operation (realstor-4strat), although less pronounced. We thus conclude that strategic storage operators generally under-utilize their capacities. Our results indicate that non-strategic storage operation should be ensured if high storage utilization is a policy objective.

Regarding welfare, we find that introducing storage increases overall welfare all cases except the strategic counterstor-E.ONstrat. Looking at the counterfactual scenarios, consumer rent and overall welfare are much higher in the non-strategic case than in the strategic one. Consumers are even worse off in counterstor-E.ONstrat compared to the reference case without storage. Accordingly, storage facilities should not be exclusively operated by a single strategic player from a consumer perspective. Our results imply that storage operation by a non-strategic players may provide an opportunity for mitigating generation-related market power. Looking at the cases where storage capacities are distributed realistically among players, we also find that consumer rent is higher in the non-strategic realstor-allcomp case compared to the strategic realstor-4strat, although less pronounced than in the counterfactual cases. Nonetheless, strategic storage harms consumers much less if storage capacities are distributed among several strategic players (realstor-4strat) compared to the case where the whole storage capacity is concentrated at a single strategic player (counterstor-E.ONstrat). Total producer rent decreases after introducing storage in all scenarios except counterstor-E.ONstrat due to the price-smoothing effect of storage. From this we conclude that storage investments might not be very attractive for the market players in Germany.

We have to note that our welfare results do not perfectly reflect the real situation on the German electricity market, since prices in our model do not fluctuate as heavily as they do in reality. This is due to imperfect foresight in the real world, and due to missing ramping cost components. Our welfare results also show some sensitivity to demand elasticity $\sigma$. We can, however, expect that the welfare effects of introducing storage were even greater in the case of larger price fluctuations.

From our analysis, we draw the conclusion that not only the amount of installed storage capacities matters, but also their operation. In electricity markets with imperfect competition, it should not be taken for granted that existing storage capacities will always be fully utilized, or that they will be operated in a welfare-maximizing way. Moreover, pumped storage as such might provide previously unnoticed possibilities for exerting market power in electricity markets, since players not only strategically decide on storage outputs - comparable to dispatchable hydro in the traditional literature on hydro-dominated markets - but also on storage inputs.

Under-utilization of storage capacities by strategic players may form an obstacle to large-scale renewable energy integration, which requires storage capacities to be utilized
to the greatest extent. Although we did not model wind integration, our findings imply that there may be a need for economic regulation of storage operators in order to achieve a maximum level of storage utilization. From a renewable energy integration perspective, it should be ensured that the total storage capacity is distributed between different players, and that they operate it in a non-strategic way. This might be particularly important for large future storage capacities that are currently being discussed, for example compressed air storage or advanced batteries19.

Our findings are also relevant in the light of ongoing discussions about future electricity system designs. For example, electricity storage is an important part of the ‘Smart Grid’ concept20. Likewise, the idea of a pan-European ‘Super Grid’, which envisions wide-area transmission of renewable electricity, also includes large-scale electricity storage for balancing purposes, for example pumped hydro storage in the Alps or in Scandinavian countries. Trieb et al. (2006) provide an example of such a concept. Last, but not least, the much-discussed idea of plug-in electric vehicles may result in large future grid storage capacities. Centralized loading and discharging of these battery capacities might be prone to strategic operation. From a regulatory perspective, it is an important question which players should coordinate loading and discharging of such vehicle fleets.

As for future research, we recommend including strategic storage into other electricity market models. A future application of ElStorM will analyze strategic storage in the light of large-scale wind integration. Another ElStorM application will analyze market impacts of future plug-in electric vehicle fleets, which introduce both dispatchable demand and additional storage capacities to the electricity system. Another possible field for research is expanding our storage mechanism towards a representation of demand-side measures like load shifting or interruptible load.

\footnote{19For example, see U.S. Department of Energy http://www.sandia.gov/ess/index.html or Electricity Storage Association http://www.electricitystorage.org/site/technologies/}

\footnote{20Compare the European Technology Platform for the Electricity Networks of the Future, http://www.smartgrids.eu}
References


6 Appendix

<table>
<thead>
<tr>
<th></th>
<th>counterstor-</th>
<th>realstor-</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>nostor</td>
<td>Fringecomp</td>
</tr>
<tr>
<td>Total storage output in GWh</td>
<td>0</td>
<td>130</td>
</tr>
<tr>
<td>Number of binding ramping restrictions:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ramping up</td>
<td>231</td>
<td>167</td>
</tr>
<tr>
<td>Ramping down</td>
<td>195</td>
<td>134</td>
</tr>
<tr>
<td>Total</td>
<td>426</td>
<td>301</td>
</tr>
</tbody>
</table>

Table 5: Comparison of storage utilization and binding ramping restrictions

<table>
<thead>
<tr>
<th></th>
<th>counterstor-</th>
<th>realstor-</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>nostor</td>
<td>Fringecomp</td>
</tr>
<tr>
<td>Absolute change compared to nostor in €:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total welfare change</td>
<td>+3,559,808</td>
<td>-43,680</td>
</tr>
<tr>
<td>Consumer rent change</td>
<td>+7,096,704</td>
<td>-631,232</td>
</tr>
<tr>
<td>Total producer rent change</td>
<td>-3,536,918</td>
<td>+587,551</td>
</tr>
</tbody>
</table>

Relative change compared to nostor in %:

<table>
<thead>
<tr>
<th></th>
<th>counterstor-</th>
<th>realstor-</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>nostor</td>
<td>Fringecomp</td>
</tr>
<tr>
<td>Total producer rent change</td>
<td>-0.79%</td>
<td>+0.13%</td>
</tr>
<tr>
<td>EnBW producer rent change</td>
<td>-0.78%</td>
<td>+0.13%</td>
</tr>
<tr>
<td>E.ON producer rent change</td>
<td>-1.43%</td>
<td>+0.10%</td>
</tr>
<tr>
<td>RWE producer rent change</td>
<td>-0.78%</td>
<td>+0.14%</td>
</tr>
<tr>
<td>Vattenfall producer rent change</td>
<td>-0.86%</td>
<td>+0.15%</td>
</tr>
<tr>
<td>Fringe producer rent change</td>
<td>+1.46%</td>
<td>+0.16%</td>
</tr>
</tbody>
</table>

Table 6: Comparison of welfare results