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Wolf-Peter Schill • Claudia Kemfert

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DIW Berlin
German Institute for Economic Research
Mohrenstr. 58
10117 Berlin
Tel. +49 (30) 897 89-0
Fax +49 (30) 897 89-200
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The Effect of Market Power on Electricity Storage Utilization: The Case of Pumped Hydro Storage in Germany

Updated Version March 2010

Wolf-Peter Schill[a,1,*], Claudia Kemfert[a,2]

[a] *DIW Berlin, Department of Energy, Transportation, Environment, Mohrenstraße 58, 10117 Berlin, Germany*

Abstract

We develop a game-theoretic electricity market model that allows analyzing strategic electricity storage in an imperfect market setting. We apply the model to Germany and examine different cases of strategic and non-strategic pumped hydro storage operation. We find that introducing storage generally smoothes conventional generation patterns and market prices and increases consumer rent and overall welfare. In contrast, electricity producers generally suffer from storage. We also find that the utilization of storage capacities depends on their operator's ability to exert market power both regarding storage and conventional generation. In particular, strategic operators tend to under-utilize their storage capacities, which in turn has welfare implications. The distribution of storage among players also matters. Accordingly, economic regulation of existing and future storage capacities may be necessary.

Keywords: Electric Power Markets, Storage, Market Power, Nash-Cournot
JEL: Q40, Q41, L13, D43

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*Corresponding author.
Email addresses: wschill@diw.de (Wolf-Peter Schill), ckemfert@diw.de (Claudia Kemfert)
[1] Tel.: +49 30 89789-675; Fax: +49 30 89789-113. The author is a member of the Graduate Center of Economic and Social Research, DIW Berlin.
[2] Tel.: +49 30 89789-663; Fax: +49 30 89789-113.

1. Introduction

Electricity storage has recently received increasing attention. For example, additional storage capacities may be required for integrating large amounts of fluctuating renewable energy into electricity systems. Future plug-in electric vehicles could provide substantial grid storage capacities. Currently, the major large-scale storage technology 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 and advanced batteries. Most electricity market models, however, neglect storage altogether. In particular, there is little research on the issue of strategic storage operation. In this paper, we analyze the impact of storage on conventional electricity generation and on market outcomes in an imperfect market setting. We examine how strategic and non-strategic storage operators differ in their utilization of storage capacities and how this affects market outcomes.

For this purpose, we develop the oligopolistic, game-theoretic Cournot model ElStorM (Electricity Storage Model). It allows analyzing strategic and non-strategic storage operation by various players who may also have market power regarding their conventional generation capacities. We apply the model to the German electricity market and the technology of pumped hydro storage. We examine counterfactual and realistic cases of pumped storage operation and compare the results regarding storage utilization, ramping requirements for conventional generation technologies, and welfare. Our main finding is that the utilization of a given storage capacity depends on its distribution among market players and on the market power of its owner(s). Strategic operators tend to under-utilize their storage capacities compared to competitive players. It should thus not be expected that storage capacities in imperfect electricity markets will be utilized to the fullest extent. This finding not only has welfare implications, but might also have consequences for the potential of future storage capacities to integrate fluctuating renewable energy. Depending on policy objectives, economic regulation of storage facilities might thus be necessary.

The paper is structured as follows. First, we discuss the relevant literature. Section 3 introduces the model ElStorM. Section 4 provides data and defines four different cases of strategic and non-strategic storage operation. Section 5.1 analyzes the impact of electricity storage on market outcomes in the simplest, counterfactual storage case. In section 5.2, we compare the four different cases of strategic and non-strategic storage operation regarding storage utilization, ramping of conventional generators and welfare. Section 5.3 examines why producers generally suffer from introducing storage in our model application. The last section summarizes and concludes.

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 approaches are used. Ventosa et al. (2005) review and classify various model types 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 the third approach, which is most suitable for analyzing market power issues. Equilibrium models are able to 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.

A large strand of literature analyzes imperfect competition in power power markets with Cournot models. Borenstein and Bushnell (1999) apply a Cournot oligopoly model to the Californian power market. They find that the potential for market power is particularly high in peak load hours. Lise et al. (2006) apply a Cournot model to the Northwestern European electricity market. They quantify how market power exertion by large producers harms consumers in different scenarios. The model includes environmental externalities like greenhouse gas emissions as well as two different 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. Lise and Kruse-mann (2008) model long-term investment decisions in a Cournot framework. With their recursive dynamic model dynLEM they simulate cost composition, investments and price paths for electricity markets between 2000 and 2050.

The models mentioned above do neither feature an hourly time representation, nor technical inter-period constraints. They rather draw on aggregated values. In contrast, Traber and Kemfert (2009a) introduce a game-theoretic model called ESYMMETRY which includes an hourly time resolution as well as some technical start-up constraints and related costs. They use the model for analyzing the impact of wind power on incentives for investments in thermal power plants. The authors find that increasing wind supply decreases investment incentives especially for natural gas plants. Their results, however, show that additional wind supply hardly substitutes conventional power generation.

Regarding electricity storage, some recent articles analyze storage in a perfect competition setting. For example, Crampes and Moreaux (2009) theoretically analyze how firms' combined decisions on hydro storage and thermal plants can lead to energy and cost savings. They find that combining storage with inflexible generation may result in net social welfare gains. Sioshansi et al. (2009) analyze electricity storage in the PJM market with a non-strategic optimization model and quantify the arbitrage value captured by storage owners. Since storage decreases peak prices and increases off-peak prices, they find that consumers benefit from storage while producers lose.

The strand of game-theoretic literature dealing with electricity storage is rather limited. There are several models that analyze 'hydro storage' in the sense of dispatchable hydro power: Hydro reservoirs allow generators to strategically shift production capacities from one period to another. Yet, most of these models assume 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 discharging, but not on storage loading. Rangel (2008) provides the most recent literature review on such strategic hydro scheduling in hydro-dominated markets like New Zealand, Norway and some South American countries. While market power potentials are usually related to exploiting temporal and geographical market separation, demand fluctuations or transmission capacity constraints, Rangel shows that players in hydro-dominated markets may also exploit market power potentials related to hydrological conditions, reservoir levels and inflow probabilities. He thus 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 of hydro power is an important factor in determining the extent of market power. Johnsen (2001) further explores this issue with 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. Garcia et al. (2001) develop an oligopoly model with dynamic Bertrand competition of hydro generators. Their simplified framework includes two players that hold equally sized, stochastically replenishing hydro reservoirs. They 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 multi-period 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. 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 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 storage utilization, since it not only deals with the strategic allocation of self-replenishing hydro resources between periods, but also with firms' strategic decisions on storage loading. By providing an analysis of strategic pumped hydro storage[3] operation, this paper complements the body of literature that deals with the possibilities of exerting market power in electricity markets.

While the general model formulation is related to Traber and Kemfert (2009a), ElStorM provides a substantial extension of the Bushnell (2003) hydro-thermal scheduling approach. In contrast to the recent non-strategic model developed by Sioshansi et al. (2009), we explicitly model combined decisions of strategic players on storage operation and on conventional electricity generation. Features like uncertainty, investment decisions, and transmission constraints[4] have been excluded since they would significantly add to complexity without substantially contributing to our analysis of strategic storage. Instead, we focus on market imperfections and strategic behavior in a Cournot setting.

3. The model ElStorM

In our game-theoretic model ElStorM, firms maximize profits by deciding on hourly electricity generation levels of different technologies as well as hourly pumped hydro storage loading and discharging. In doing so, players face a range of technical constraints. A 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 not only electricity storage and an hourly time resolution, but also inter-period constraints for both conventional generation technologies and pumped storage. 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

[3] We focus on pumped hydro storage because it is the only large-scale storage technology 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.

[4] Leuthold et al. (2008) provide a recent example of a model that includes a representation of the European high-voltage electricity transmission network. Neuhoff et al. (2005) 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 behavioral assumptions on transmission and market design.

Item	Description	Unit
Sets and indices		
F	Firms with $f \in F$	
I	Generation technologies with $i \in I$	
T	Time with time periods $t \in T$, $\tau \in T$	hours
Parameters		
σ	Price elasticity of electricity demand	
$d0_t$	Hourly reference demand	MWh
$p0_t$	Hourly reference prices	€/MWh
$\overline{x}_{f,i}^{maxgen}$	Installed conventional generation capacity	MW
$\overline{st}_f^{maxout}$	Installed pumped storage discharging capacity	MW
$\overline{st}_f^{maxin}$	Installed pumped storage loading capacity	MW
$\overline{st}_f^{cap}$	Installed pumped storage capacity	MWh
$\xi_{up,i}$	Ramping up parameter for conventional generation	
$\xi_{down,i}$	Ramping down parameter for conventional generation	
vgc_i	Variable generation costs	€/MWh
$vstc$	Variable pumped storage costs	€/MWh
ovc_i	Other variable cost	€/MWh
fp_i	Fuel price	€/MWh$_{th}$
ep	Carbon emission price	€/t
se_i	Specific carbon emission	t/MWh
η_i	Generation efficiency	
η_{st}	Storage efficiency	
$\theta_{gen,f,i,t}$	Market power parameter for generation	0 or 1
$\theta_{st,f,t}$	Market power parameter for pumped storage	0 or 1
Variables		
Π_f	Profit of firm f	€
p_t	Price of period t	€/MWh
$x_{f,i,t}$	Generation of firm f with technology i in period t	MWh
X_t	Total supply in period t	MWh
$stout_{f,t}$	Generation of firm f in period t from pumped storage	MWh
$stin_{f,t}$	Pumped storage loading of firm f in period t	MWh
$\lambda_{gencap,f,i,t}$	Shadow price of conventional generation capacity constraint	€/MWh
$\lambda_{rup,f,i,t}$	Shadow price of ramping up constraint	€/MWh
$\lambda_{rdo,f,i,t}$	Shadow price of ramping down constraint	€/MWh
$\lambda_{stoutcap,f,t}$	Shadow price of storage discharging capacity constraint	€/MWh
$\lambda_{stincap,f,t}$	Shadow price of storage loading capacity constraint	€/MWh
λ_{stup}	Shadow price of upper storage capacity constraint	€/MWh
λ_{stlo}	Shadow price of lower storage capacity constraint	€/MWh
$\vartheta_{f,i,t}$	Market share of firm f - conventional generation	
$\vartheta_{f,t}^{out}$	Market share of firm f - storage discharging	
$\vartheta_{f,t}^{in}$	Market share of firm f - storage loading	
$crent_t$	Consumer rent of period t	€
$prent_{f,t}$	Producer rent of firm f in period t	€

Table 1: Sets, indices, parameters and variables

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 $stin_{f,t}$ and discharging $stout_{f,t}$ of their pumped hydro storage capacities. Each player faces the following constrained maximization problem:

$$\max_{\substack{x_{f,i,t}\\ stin_{f,t}\\ stout_{f,t}}} \left[\sum_{t \in T} \left[p_t \left(\sum_{i \in I} x_{f,i,t} + stout_{f,t} - stin_{f,t} \right) - \sum_{i \in I} vgc_i x_{f,i,t} - vstc \cdot stout_{f,t} \right] \right] \tag{1a}$$

$$s.t. \quad x_{f,i,t} - \overline{x}^{maxgen}_{f,i} \leq 0, \ \forall f,i,t \ (\lambda_{gencap,f,i,t}) \tag{1b}$$

$$x_{f,i,t} - x_{f,i,t-1} - \xi_{up,i} \overline{x}^{maxgen}_{f,i} \leq 0, \ \forall f,i,t \ (\lambda_{rup,f,i,t}) \tag{1c}$$

$$x_{f,i,t-1} - x_{f,i,t} - \xi_{down,i} \overline{x}^{maxgen}_{f,i} \leq 0, \ \forall f,i,t \ (\lambda_{rdo,f,i,t}) \tag{1d}$$

$$stout_{f,t} - \overline{st}^{maxout}_{f} \leq 0, \ \forall f,t \ (\lambda_{stoutcap,f,t}) \tag{1e}$$

$$stin_{f,t} - \overline{st}^{maxin}_{f} \leq 0, \ \forall f,t \ (\lambda_{stincap,f,t}) \tag{1f}$$

$$\sum_{\tau=1}^{t} stout_{f,\tau} - \sum_{\tau=1}^{t-1} stin_{f,\tau} \eta_{st} \leq 0, \ \forall f,t \ (\lambda_{stlo,f,t}) \tag{1g}$$

$$\sum_{\tau=1}^{t} stin_{f,\tau} \eta_{st} - \sum_{\tau=1}^{t-1} stout_{f,\tau} - \overline{st}^{cap}_{f} \leq 0, \ \forall f,t \ (\lambda_{stup,f,t}) \tag{1h}$$

$$x_{f,i,t} \geq 0, \ \forall f,i,t \tag{1i}$$

$$stin_{f,t}, stout_{f,t} \geq 0, \ \forall f,t \tag{1j}$$

The objective function (1a) represents player f's profit function. It adds up revenues from selling electricity generated by conventional technologies $\sum_{i \in I} p_t x_{f,i,t}$ and by pumped storage $p_t stout_{f,t}$ of each period 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 depends on a firm's decisions on conventional output, storage loading, and storage discharging. On the cost side, (1a) includes technology-specific variable generation costs $\sum_{i \in I} vgc_i x_{f,i,t}$. As shown in equation (2) below, vgc_i depend on fuel prices fp_i, emission prices ep, specific emissions se_i, technology-specific generation efficiency η_i and other variable costs ovc_i.[5] The profit function also includes variable costs of storage operation $vstc \cdot stout_{f,t}$, mainly reflecting maintenance costs. These costs are assumed to be constant for every unit of electricity generated and assigned to storage loading.[6] Furthermore, (1a) includes the costs $p_t stin_{f,t}$, reflecting the fact that electricity stored at period t had to be bought

[5]This type of cost representation is derived from Traber and Kemfert (2009a).

[6]It does not matter if variable storage costs are assigned to storage loading or discharging.

or could have been sold on the market at the price p_t. Firms thus face costs equal to the market price p_t for each unit of electricity stored at time t.

$$vgc_i = \frac{fp_i + ep \cdot se_i}{\eta_i} + ovc_i, \ \forall i \tag{2}$$

Condition (1b) represents maximum generation capacity restrictions. For each conventional technology i, a firm's actual power generation cannot exceed its installed capacity.[7] (1c) and (1d) are inter-period constraints. (1c) is a 'ramping up' restriction: between two subsequent 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. $\xi_{up,i}$ takes on values between 0 and 1. While $\xi_{up,i}$ is relatively small for inflexible nuclear power, it assumes the value 1 for perfectly flexible technologies. Likewise, condition (1d) 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 (1e) to (1h) relate to pumped hydro storage. Condition (1e) resembles (1b) and states that the amount of electricity generated from pumped storage cannot exceed the installed generating capacity in any period t. Likewise, condition (1f) constrains the amount of electricity that can be loaded into the storage facility at any period t, i.e. represents limited pumping capacities. Conditions (1g) and (1h) are restrictions on energy storage capacities, that is on available reservoirs. (1g) ensures that generation from storage stops once the reservoir is 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 (1h) represents the upper storage capacity constraint. For each period t, the amount that can be loaded into the storage facility cannot exceed the total reservoir capacity, given the history of inflows and outflows up to this period. This restriction makes sure that reservoirs never overflow. Conditions (1g) and (1h) include efficiency losses: since pumped storage facilities are not perfectly efficient, only a share η_{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 (1i) and (1j) ensure non-negativity of the variables $x_{f,i,t}$, $stin_{f,t}$ and $stout_{f,t}$.

The market clearing condition (3) is required to ensure that supply equals demand in every period. As in several other models[8], demand is represented by an iso-elastic function, drawing on exogenous hourly reference demands $d0_t$ and prices $p0_t$. σ is the price elasticity of demand. X_t represents total electricity supply, consisting of the total amount of electricity generated by all firms and

[7]We refrain from modeling individual power plants and rather focus on a firm's cumulative installed capacity of a given technology. This formulation avoids mixed-integer unit commitment problems, which would invalidate the KKT conditions for each player's optimization problem. Solving the resulting Nash-equilibrium problem would be much harder in the mixed-integer case, if at all possible.

[8]For example, Borenstein and Bushnell (1999) or Traber and Kemfert (2009b).

technologies, plus generation from pumped storage, minus storage loading, as shown in (4).

$$X_t = d0_t \left(\frac{p_t}{p0_t}\right)^{-\sigma}, \ \forall t \tag{3}$$

$$X_t = \sum_{f \in F} \Big[\sum_{i \in I} x_{f,i,t} + stout_{f,t} - stin_{f,t} \Big], \ \forall t \tag{4}$$

We formulate the optimization problem as a mixed complementarity problem (MCP), which is a more suitable formulation for 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 and can thus be used for modeling Karush-Kuhn-Tucker (KKT) optimality conditions. With a convex underlying optimization problem, as (1a-1j), the KKT approach leads to a globally optimal solution. We combine the market clearing condition (3) with (4), solve for p_t and insert it into (1a). We then derive the KKT optimality conditions from the optimization problem. This results in equations (5a-5k), which form our nonlinear mixed complementarity problem:

$$\begin{aligned} 0 \leq vgc_i &+ \lambda_{gencap,f,i,t} \\ &+ \lambda_{rup,f,i,t} - \lambda_{rup,f,i,t+1} - \lambda_{rdo,f,i,t} + \lambda_{rdo,f,i,t+1} \\ &- p_t \left(1 - \frac{\sum_{i \in I} \vartheta_{f,i,t}\theta_{gen,f,i,t} + \vartheta^{out}_{f,t}\theta_{st,f,t} - \vartheta^{in}_{f,t}\theta_{st,f,t}}{\sigma}\right) \\ &\perp \quad x_{f,i,t} \geq 0, \ \forall f,i,t \end{aligned} \tag{5a}$$

$$\begin{aligned} 0 \leq vstc_{st} &+ \lambda_{stoutcap,f,t} + \sum_{\tau=t}^{T} \lambda_{stlo,f,\tau} - \sum_{\tau=t}^{T-1} \lambda_{stup,f,\tau+1} \\ &- p_t \left(1 - \frac{\sum_{i \in I} \vartheta_{f,i,t}\theta_{gen,f,i,t} + \vartheta^{out}_{f,t}\theta_{st,f,t} - \vartheta^{in}_{f,t}\theta_{st,f,t}}{\sigma}\right) \\ &\perp \quad stout_{f,i,t} \geq 0, \ \forall f,t \end{aligned} \tag{5b}$$

$$\begin{aligned} 0 \leq \lambda_{stincap,f,t} &- \sum_{\tau=t}^{T-1} \lambda_{stlo,f,\tau+1}\eta_{st} + \sum_{\tau=t}^{T} \lambda_{stup,f,\tau}\eta_{st} \\ &+ p_t \left(1 - \frac{\sum_{i \in I} \vartheta_{f,i,t}\theta_{gen,f,i,t} + \vartheta^{out}_{f,t}\theta_{st,f,t} - \vartheta^{in}_{f,t}\theta_{st,f,t}}{\sigma}\right) \\ &\perp \quad stin_{f,i,t} \geq 0, \ \forall f,t \end{aligned} \tag{5c}$$

$$0 \leq -x_{f,i,t} + \overline{x}_{f,i}^{maxgen}$$

$$\perp \lambda_{gencap,f,i,t} \geq 0, \ \forall f, i, t \quad (5d)$$

$$0 \leq -x_{f,i,t} + x_{f,i,t-1} + \xi_{up,i}\overline{x}_{f,i}^{maxgen}$$

$$\perp \lambda_{rup,f,i,t} \geq 0, \ \forall f, i, t \quad (5e)$$

$$0 \leq -x_{f,i,t-1} + x_{f,i,t} + \xi_{down,i}\overline{x}_{f,i}^{maxgen}$$

$$\perp \lambda_{rdo,f,i,t} \geq 0, \ \forall f, i, t \quad (5f)$$

$$0 \leq -stout_{f,t} + \overline{st}_{f}^{maxout}$$

$$\perp \lambda_{stoutcap,f,t} \geq 0, \ \forall f, t \quad (5g)$$

$$0 \leq -stin_{f,t} + \overline{st}_{f}^{maxin}$$

$$\perp \lambda_{stincap,f,t} \geq 0, \ \forall f, t \quad (5h)$$

$$0 \leq -\sum_{\tau=1}^{t} stout_{f,\tau} + \sum_{\tau=1}^{t-1} stin_{f,\tau}\eta_{st}$$

$$\perp \lambda_{stlo,f,t} \geq 0, \ \forall f, t \quad (5i)$$

$$0 \leq -\sum_{\tau=1}^{t} stin_{f,\tau}\eta_{st} + \sum_{\tau=1}^{t-1} stout_{f,\tau} + \overline{st}_{f}^{cap}$$

$$\perp \lambda_{stup,f,t} \geq 0, \ \forall f, t \quad (5j)$$

$$0 = X_t - d0_t \left(\frac{p_t}{p0_t}\right)^{-\sigma},$$

$$p_t \ free, \ \forall \ t \quad (5k)$$

Equations (5a-5k) include market shares $\vartheta_{f,i,t}$, $\vartheta_{f,t}^{out}$ and $\vartheta_{f,t}^{in}$ as defined in (6a-6c). They indicate a firm's market power regarding generation and storage. (5a-5k) 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.

$$\vartheta_{f,i,t} = \frac{x_{f,i,t}}{X_t}, \ \forall f, i, t \quad (6a)$$

$$\vartheta_{f,t}^{out} = \frac{stout_{f,t}}{X_t}, \ \forall f, t \quad (6b)$$

$$\vartheta_{f,t}^{in} = \frac{stin_{f,t}}{X_t}, \ \forall f, t \quad (6c)$$

Conditions (5a-5c) may be interpreted as follows. Equation (5a) includes a standard Cournot result: In case of positive market shares $\sum_{i \in I} \vartheta_{f,i,t}$ for conventional generation technologies, market prices exceed the sum of marginal costs and shadow prices of player f. The larger the market share of a player, the larger its ability to raise prices beyond marginal costs. While this is a common result of Cournot models, the inclusion of storage-related market shares $\vartheta_{f,t}^{out}$ and $\vartheta_{f,t}^{in}$ is a new contribution to the literature. Positive market shares regarding storage output $\vartheta_{f,t}^{out}$ have the same effect as positive 'conventional' market shares: larger $\vartheta_{f,t}^{out}$ increase a firm's ability to raise prices beyond marginal costs. The market share of storage input $\vartheta_{f,t}^{in}$, however, enters with a negative sign. Keep in mind that a firm faces costs for each MWh of electricity that is stored at period t. Thus, higher prices imply higher storage loading costs. The higher the market share $\vartheta_{f,t}^{in}$ of a player, the larger its interest in low prices during periods of storage loading. Strategically operated storage capacities thus mitigate a strategic player's incentives to raise prices by withholding conventional capacities during the periods of storage loading.

Condition (5b) 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 $\vartheta_{f,t}^{out}$. If a player also generates with conventional technologies, its cumulative market shares $\sum_{i \in I} \vartheta_{f,i,t}$ of these technologies allow raising prices. Again, high storage loading market shares mitigate a strategic player's incentives to raise prices, since $\vartheta_{f,t}^{in}$ enters with a negative sign.

Equations (5a-5k) 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 (Section 4). The problem is solved with the solver PATH, which represents a generalization of Newton's method, including a path search (Ferris and Munson, 2000).

After solving the complementarity problem, consumer rent and producer rent are calculated. Consumer rent of period t is determined according to equation (7a) by integrating the demand function from 0 up to the the actual quantity and subtracting the amount actually paid.[9] Producer rent for each player is calculated according to equation (7b) by summing up revenues and subtracting

[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.

costs.

$$crent_t = \int_0^{X_t} p0_t \left(\frac{x}{d0_t}\right)^{-\frac{1}{\sigma}} dx - p_t X_t, \ \forall t \tag{7a}$$

$$\begin{aligned} prent_{f,t} = & \sum_{i \in I} x_{f,i,t}(p_t - vgc_i) \\ & + stout_{f,t}(p_t - vstc) - stin_{f,t} p_t, \ \forall f, t \end{aligned} \tag{7b}$$

4. Data and scenarios

The data used in the model represents the German electricity market. Regarding reference demand $d0$ and reference prices $p0$, 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 $\sigma = 0.4$. 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, σ 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 more than 80% of total German generation capacity. We include an additional competitive fringe player named 'Fringe' and assign him the remaining generation capacities. Table 2 shows installed conventional generation capacities 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 (2009b).

	EnBW	**E.ON**	**RWE**	**Vattenfall**	**Fringe**
Installed conventional generation capacities in MW:					
Nuclear	4,019	7,639	3,536	1,418	957
Lignite	404	1,320	8,614	7,303	409
Hard coal	2,674	9,933	4,453	1,667	6,136
Natural gas	1,044	3,871	2,982	2,103	6,548
Oil	440	1,483	21	646	541
Hydro	427	1,507	638	0	893
Installed storage capacities:					
Storage loading and discharging rate in MW	1,006	1,017	1,023	2,893	456
Storage capacity in MWh	7,200	6,790	6,959	17,141	2,202

Table 2: Installed generation and storage capacities

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

[10] http://www.eex.com/en/Market Data/Trading Data/Power, last accessed 14 January 2009.

[11] For example, compare Borenstein and Bushnell (1999) or Traber and Kemfert (2009b).

numerical simulation. Average availabilities are calculated from EEX data.[12] Moreover, the capacities of Traber and Kemfert (2009b) do not exactly match the registered capacities at EEX. In order to ensure consistency with reference price and demand data, 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[13], costs, emission and efficiency parameters. Data sources include Traber and Kemfert (2009a), dena (2005), EEX, UCTE, the International Energy Agency and own calculations. In addition, we assume a carbon emission price ep of €10/t.

	Nuclear	**Lignite**	**Hard Coal**	**Natural Gas**	**Oil**	**Hydro**
Availability and adjustment	87%	92%	58%	62%	55%	79%
Ramping parameters $\xi_{up,i} = \xi_{down,i}$	0.04	0.04	0.25	0.30	0.80	0.15
Fuel prices fp_i in €/MWh$_{th}$	2.1	4.5	7.2	21.7	17.2	0
Specific carbon emission se_i in t/MWh	0	0.40	0.34	0.19	0.28	0
Generation efficiency η_i	0.33	0.37	0.38	0.45	0.35	1.00
Other variable costs ovc_i in €/MWh	0.7	2.6	2.0	1.4	1.5	2.6

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 2 shows how the total capacity is distributed among different players. Data sources include company reports and other publications.[14] A literature survey showed that most pumped storage plants have roughly the same capacities for loading and discharging. Thus, we assume $\overline{st}_f^{maxout} = \overline{st}_f^{maxin}$. Note that these values refer to the power of turbines and pumps, and are accordingly measured in MW. In contrast, the installed storage capacities $\overline{st}_f^{cap}$ refer to the volumes of the storage reservoirs and are thus measured in MWh. We assume that only 80% of the capacities shown

[12]http://www.eex.com/en/Transparency/Power plant information/Data/Overview, last accessed 14 January 2009.

[13]We assume equal parameters for ramping up and down, i.e. $\xi_{up,i} = \xi_{down,i}$.

[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 2, German grid operators also utilize pumped hydro storage plants in neighboring countries to some extent. For reasons of traceability and consistency, we only draw on domestic capacities. Note that 'Schluchseewerk' is a large German pumped hydro storage operator who 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.

in Table 2 are available. On the one hand, this is due to outages and regular 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.[15] Furthermore, we assume variable storage operation costs $vstc_{pumpstor}$ of € 1/MWh generated from pumped storage and average storage efficiency of $\eta_{pumpstor} = 0.75$.[16] That is, for each MWh that is loaded into pumped storage facilities, only 0.75 MWh can be retreived again.

Five different cases are analyzed. First, we exclude pumped storage altogether in the **nostor** scenario in order to establish a base case. 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 pump storage in a non-strategic way, just like its other generation assets ($\theta_{st,Fringe,t} = 0\ \forall i, t$). In contrast, we assume that E.ON operates its storage capacities as well as its conventional generation assets in a strategic way ($\theta_{st,E.ON,t} = 1\ \forall t$). 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 2). In the **realstor-allcomp** case, all players operate their storage capacities in a non-strategic way ($\theta_{st,f,t} = 0\ \forall f, t$). In contrast, in the **realstor-4strat** case, the four largest players operate their storage capacities strategically, just like their conventional generation capacities ($\theta_{st,EnBW,t} = \theta_{st,E.ON,t} = \theta_{st,RWE,t} = \theta_{st,Vattenfall,t} = 1\ \forall t$). Note that conventional generation decisions of the four largest players are assumed to be strategic in all scenarios ($\theta_{gen,EnBW,t} = \theta_{gen,E.ON,t} = \theta_{gen,RWE,t} = \theta_{gen,Vattenfall,t} = 1\ \forall t$) while the Fringe always generates electricity competitively ($\theta_{gen,Fringe,i,t} = 0\ \forall i, t$). Analyzing the two realistic 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 base case 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.
4. **realstor-allcomp**: Realistic storage capacities, all players operate storage competitively.
5. **realstor-4strat**: Realistic storage capacities, largest four players operate storage strategically.

[15] These estimations are based on interviews with industry representatives.
[16] Compare Tiedemann et al. (2008).

5. Results

5.1. General effects of introducing storage

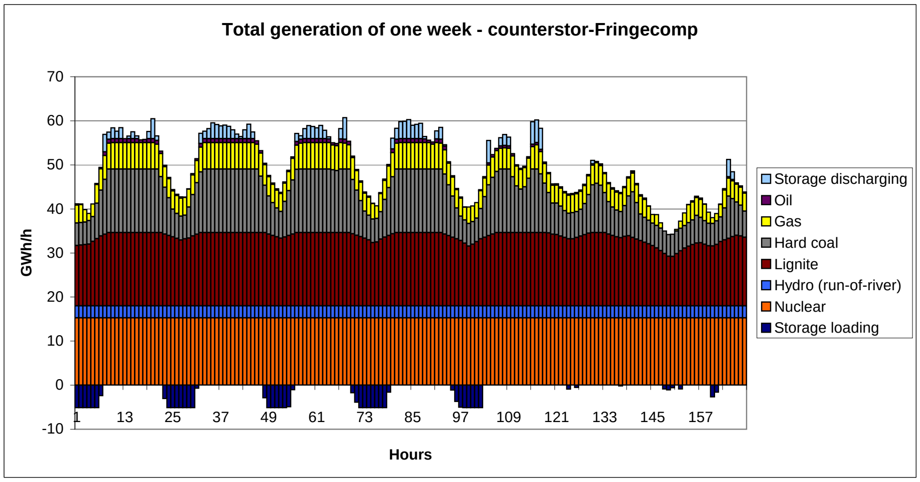

Figure 1: Total generation of one week in the **counterstor-Fringecomp** case

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 $\theta_{st,Fringe,t} = 0 \; \forall t$. Figure 1 shows storage loading and discharging in the context of total electricity generation for one week. 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 observable for most days. Nuclear and run-of-river hydro plants 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.

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. Figure 2 illustrates storage operation in the respective week in more detail. Obviously, storage always needs to be loaded before it can be discharged. The pattern of nighttime loading and peak-hour discharging is clearly visible. Sensitivity analyses show that assuming lower storage efficiency and/or or higher storage costs results in similar storage patterns, but in lower overall storage utilization.

Introducing pumped storage 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

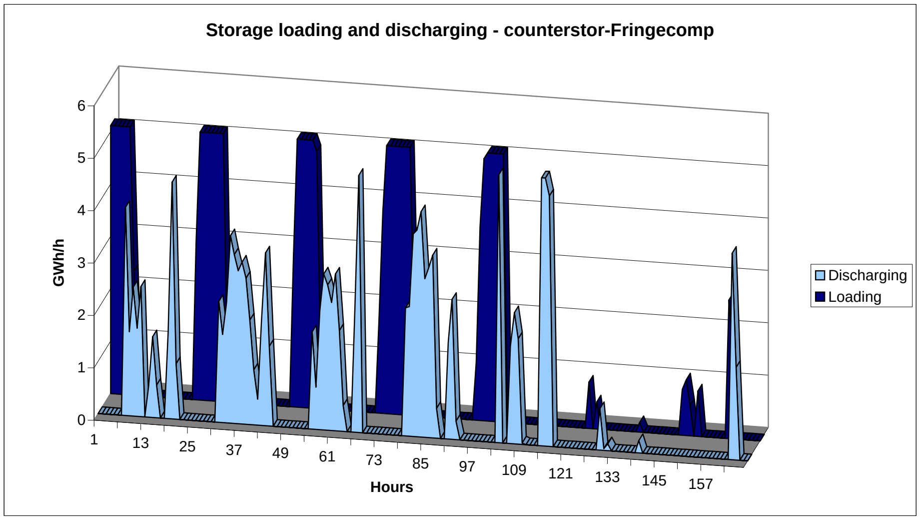

Figure 2: Storage loading and discharging in the **counterstor-Fringecomp** case

from 448 in the **nostor** case to 384 in the **counterstor-Fringecomp** case. Storage thus has a smoothing effect on conventional electricity generation - in particular, regarding hard coal and lignite.[17]

The introduction of pumped storage also has a smoothing effect on market prices. Storage allows to increase the utilization of cheap base-load power and to decrease expensive peak load generation. Storage substantially decreases peak prices and only moderately increases off-peak prices. Figure 3 illustrates this result by comparing prices of the **nostor** and **counterstor-Fringecomp** cases. Since electricity demand is much higher in peak periods than in off-peak periods, the price smoothing effect of storage leads to consumer benefits of about € 24 million and to producer losses of about € 18 million over the whole week, i.e. a net welfare gain. This result corresponds with the findings of Sioshansi et al. (2009).

5.2. Strategic and non-strategic storage operation

In the following, we compare the outcomes of all scenarios outlined in section 4 regarding storage utilization, ramping requirements and welfare. Our main finding is that the utilization of the same total storage capacity depends on the storage operator and on its ability to exert market power both regarding storage and conventional generation capacities. In turn, the number of binding ramping restrictions and welfare results also depend on the storage operator. Table 4 shows the major results.

[17] Although we cannot go into details in this context, this effect of storage is very valuable for renewable electricity expansion, since intermittent sources like wind generally increase ramping requirements.

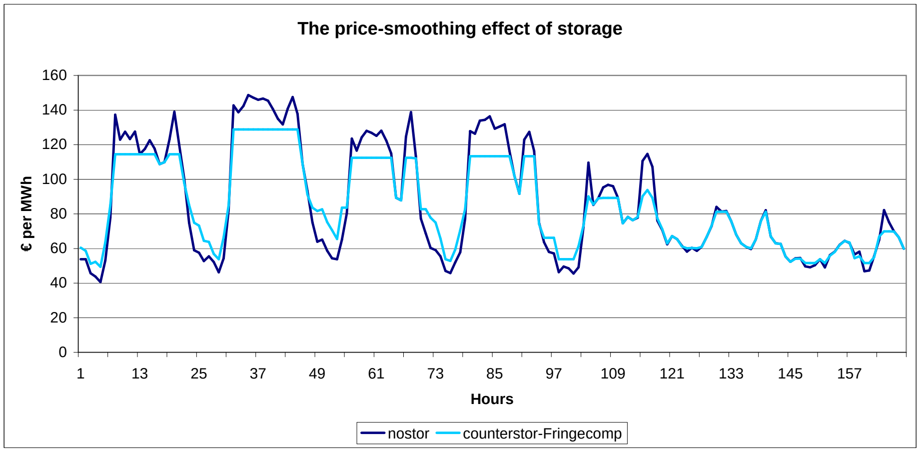

Figure 3: Comparison of prices: **nostor** and **counterstor-Fringecomp**

	nostor	**counterstor-Fringecomp**	**counterstor-E.ONstrat**	**realstor-allcomp**	**realstor-4strat**
Total generation from storage in GWh	0	146	46	168	142
Number of binding ramping restrictions:					
Ramping up	241	204	212	198	173
Ramping down	207	180	190	179	164
Total	448	384	402	377	337
Welfare change compared to **nostor** in million €:					
Consumer rent		+24.1	+11.4	+24.9	+26.3
Producer rent		-18.2	-8.3	-19.1	-19.5
Overall welfare		+5.9	+3.1	+5.8	+6.8

Table 4: Major results of different cases for one week

Figure 4 shows that total storage output over one week (168 hours) 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 setting: In the **counterstor-Fringecomp** case, where the Fringe player operates the total storage capacity in a non-strategic way (just like its other generation capacities), total storage output is around 146 GWh. In contrast, in the **counterstor-E.ONstrat** case, where the E.ON uses the same storage capacity in a strategic way (like its other generation capacities), total storage output is only 46 GWh. If storage is assigned to the players according to real data, non-strategic storage operation results in total storage output of about 168 GWh (**realstor-allcomp**), while strategic operation of the four largest players results in total storage output of only 142 GWh (**realstor-4strat**). These results indicate that a given storage capacity is utilized to the highest degree if it is distributed among several players and operated in a non-strategic way.

Regarding the impact of storage on conventional electricity generation, we

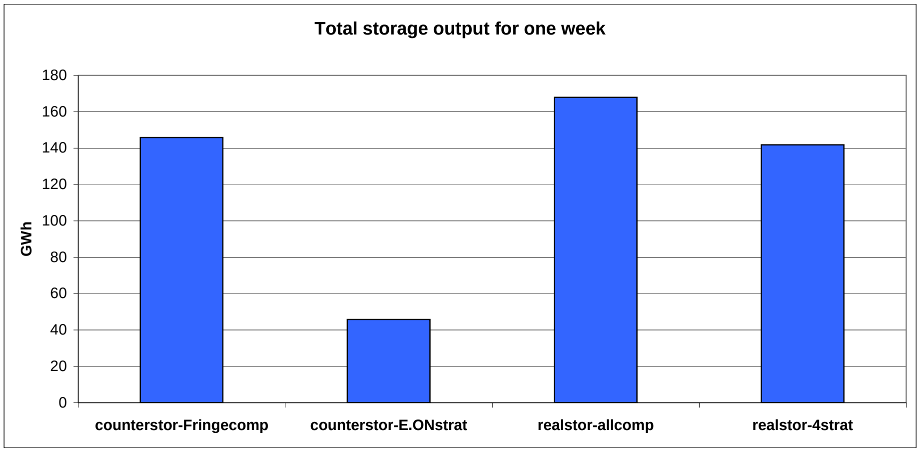

Figure 4: Comparison of total storage output for one week

find a decrease in the number of binding ramping restrictions in all cases, although results vary considerably. In the strategic **counterstor-E.ONstrat** case, where the storage capacity is under-utilized, introducing storage has the smallest impact on conventional generation. Interestingly, its smoothing effect is most visible in the **realstor-4strat** case.[18]

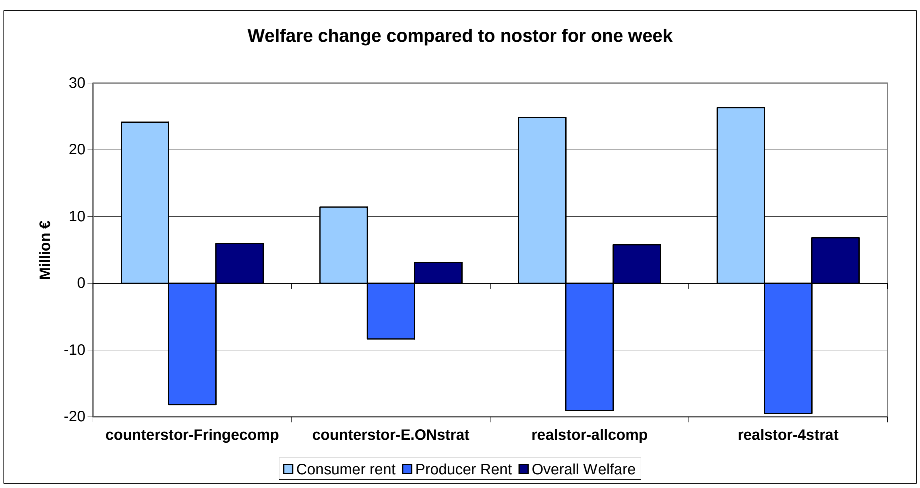

Figure 5: Welfare change compared to nostor for one week

[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, might change results.

Looking at the welfare results, we find that introducing storage increases consumer rent and overall welfare in all cases, though outcomes differ substantially. Figure 5 illustrates absolute changes in consumer rent, producer rent, and overall welfare of the four scenarios for the total week compared to the **nostor** case. Comparing the cases with counterfactual storage assignment (the two cases on the left-hand side of Figure 5), we find that consumers benefit more from introducing storage in the competitive **counterstor-Fringecomp** case, where storage utilization is high, than in the strategic **counterstor-E.ONstrat** case, where the storage capacity is under-utilized. The reason for this result is the price-smoothing effect of storage, which decreases peak prices substantially. While consumers benefit from this effect, producers suffer. Therefore, E.ON under-utilizes its storage capacity in order not to smooth prices too much. Accordingly, E.ON's producer rent in **counterstor-E.ONstrat** is much higher (about € 6 million) than in **counterstor-Fringecomp**. All other strategic producers are also better off in **counterstor-E.ONstrat** compared to **counterstor-Fringecomp**, while for the Fringe player the opposite is true. That is, other strategic players are able to free-ride on E.ON's strategic storage utilization, while the Fringe is not. Overall, introducing storage leads to a substantial overall welfare gain of around € 6 million in the non-strategic **counterstor-Fringecomp** case, and only about € 3 million in the strategic **counterstor-E.ONstrat** case.

Looking at the cases with realistic assignment of storage capacities (the two cases on the right-hand side of Figure 5), we find that consumers are slightly better off and producers slightly worse off in the strategic storage scenario compared to the competitive one. Unlike in the counterfactual cases, producers do not benefit from strategic storage operation. There is a game-theoretic explanation for this unexpected result. The four strategic storage operators might altogether be better off if they agreed to hold back some storage capacity. However, an individual player has an incentive to deviate from such an agreement: by utilizing some additional storage capacity he can make an extra arbitrage profit, while the price-smoothing effect of storage harms the other players. Since this is true for all four strategic players, they face a prisoner's dilemma situation. Finally, the **realstor-4strat** outcome materializes, where storage utilization is much higher than in the strategic **counterstor-E.ONstrat** scenario - in which only E.ON controls the total storage capacity, such that no other player can respond to E.ON's storage under-utilization. The **realstor-4strat** case leads to the lowest total producer rent of all scenarios, but to the highest consumer rent and highest overall welfare - nearly € 7 million higher than in the case without storage.[19]

	counterstor-Fringecomp-a	counterstor-Fringecomp-b	counterstor-Fringecomp	counterstor-E.ONstrat	realstor-allcomp	realstor-4strat
EnBW	-2.85%	-3.09%	-3.09%	-1.64%	-2.46%	-2.70%
E.ON	-3.81%	-3.80%	-3.95%	-0.10%	-3.79%	-3.82%
RWE	-3.59%	-3.83%	-3.99%	-2.02%	-3.76%	-3.64%
Vattenfall	-3.62%	-3.89%	-3.92%	-2.09%	-2.70%	-2.44%
Fringe	+0.19%	-0.01%	-0.11%	-2.40%	-3.92%	-4.65%
Total	-3.00%	-3.17%	-3.27%	-1.50%	-3.43%	-3.50%

Table 5: Relative producer rent changes compared to **nostor**

5.3. Why storage may harm producers in oligopolistic electricity markets

As shown on the right-hand side of Table 5, a general finding of our analysis is that every single producer suffers losses from introducing storage compared to **nostor**. This holds for all four cases analyzed above - no matter if the player operates storage competitively or not. All players would be better off if they decided not to utilize their storage capacities at all. So why do they still use them?

There is again a game-theoretic answer. Keep in mind that the model not only features strategic storage operation, but also strategic generation decisions by the four largest players. If storage is introduced to the market, these players adjust their strategic generation decisions to the new situation, which in the end leads to the results discussed above.

We demonstrate this effect for the simple example of **counterstor-Fringecomp**.[20] Starting from the case without storage, we assign the total storage capacity to the Fringe player. We assume that the four strategic players still behave as in the scenario without storage by fixing their generation decisions to the **nostor** results, and only allow the Fringe player to freely decide on conventional generation and storage operation. We name this scenario **counterstor-Fringecomp-a**. As shown in Table 5, storage now increases the Fringe's producer rent compared to the case without storage - storage would be profitable. However, given the new storage capacity in the market, the generation decisions of the strategic players are not optimal. Every strategic player has an incentive to deviate from this solution. For example, if we fix all decision variables to the result of **counterstor-Fringecomp-a** and only allow E.ON to freely decide on its conventional generation, we get the result **counterstor-Fringecomp-b**. E.ON is now slightly better off than before, while all other producers suffer losses. But again, this solution is not stable, since other strategic players have incentives to deviate from this point. In the end, we arrive at the **counterstor-Fringecomp** result, which is the stable Nash-Cournot solution. It represents another example of a prisoner's dilemma: all strategic players would have been better off if they had agreed to stick to the **counterstor-**

[19] We have to note that our model results show some sensitivity to demand elasticity σ. However, this is a common characteristic of Cournot models.

[20] Note that in this example, storage is operated competitively by the Fringe player. The remaining players, however, strategically decide on electricity generation.

Fringecomp-a solution. We find similar situations in the remaining cases, all leading to the stable Nash-Cournot solutions listed on the right-hand side of Table 5, in which no producer benefits from storage operation.

6. Summary and conclusion

We have developed ElStorM, a game-theoretic, computational Cournot model that allows to analyze strategic electricity storage utilization in an imperfect market setting. We have applied the model to the German electricity market and pumped hydro storage. Drawing on real market data and using reference demands and prices of a characteristic week in October 2008, we have analyzed four cases of strategic and non-strategic pumped storage utilization by different players that may also have market power regarding their conventional generation capacities.

We find realistic patterns of storage loading and discharging which resemble real pumped hydro storage operation cycles. Introducing storage generally relaxes ramping constraints of conventional generation technologies, smoothes market prices, decreases producer rent, and increases both consumer rent and overall welfare. Our main finding, however, is that not only the existence of a storage capacity in a market matters, but also who operates it. The utilization of a given storage capacity depends on the market power of its operator(s), i.e. the operator's ability to use storage and/or conventional generation capacities in a strategic way. The distribution of storage capacities among players also matters. In turn, varying degrees of storage utilization lead to different market results and welfare outcomes. Our analysis indicates that the interrelation of strategic and/or non-strategic electricity storage with strategic electricity generation in an imperfect electricity market is a very complex issue that may lead to counter-intuitive results.

In the counterfactual scenarios, we assign the total storage capacity either to the competitive Fringe player or to the largest strategic player E.ON. Storage utilization is much higher in the non-strategic **counterstor-Fringecomp** case compared to the strategic **counterstor-E.ONstrat** scenario. If we distribute the storage capacity realistically among the players according to actual German data, we also find that storage utilization is higher in the non-strategic **realstor-allcomp** scenario compared to the strategic **realstor-4strat** case - although less pronounced than in the counterfactual setting. We thus conclude that strategic storage operators generally under-utilize their capacities.

Looking at the welfare results, we find that consumer rent and overall welfare in the counterfactual scenarios are substantially higher in the non-strategic case than in the strategic one. The strategic **counterstor-E.ONstrat** case leads to the lowest consumer rent and lowest overall welfare of all storage scenarios. Accordingly, storage facilities should not be exclusively operated by a single strategic player from a regulatory perspective. In contrast, our results imply that exclusive storage operation by non-strategic fringe players can provide a measure for mitigating market power in imperfect electricity generation markets.

In the scenarios with a realistic distribution of storage capacities among players we find that consumer rent and overall welfare are slightly higher in the strategic **realstor-4strat** case than in the non-strategic **realstor-allcomp** one. We thus conclude that strategic storage utilization may not harm consumers if storage capacities are well-distributed. If storage is distributed properly among strategic generators, even their strategic utilization may mitigate generation-related market power.

We also find that strategic players get caught in a prisoner's dilemma. All players would be better off by not utilizing storage at all - but such a behavior does not represent a stable Nash-Cournot solution. Since storage decreases electricity generators' rents, we conclude that investing into additional storage capacities might not be very attractive for German market players - although in the real word, there are other reasons for using storage aside from arbitrage, for example providing back-up capacities and reactive power supply.

Under the assumption that the large-scale integration of fluctuating renewable energy sources like wind power requires storage capacities to be utilized to the greatest extent, under-utilization of storage capacities by strategic players may provide a serious obstacle. Although we did not model the case of wind integration here, 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.

Our findings are relevant for future European electricity system designs that rely on large storage capacities. For example, storage is an important component of the 'Smart Grids' [21] concept. 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 Scandinavian region (Trieb et al., 2006). Last, but not least, future plug-in electric vehicle fleets may provide substantial grid storage capacities. Centralized loading and discharging of these battery capacities might be prone to strategic operation. From a welfare-maximizing perspective, it should be ensured that the right players coordinate loading and discharging of such vehicle fleets.

Future applications of ElStorM will analyze strategic storage in the light of large-scale wind integration and in the context of plug-in electric vehicle fleets, which add both dispatchable load and additional storage capacities to the electricity system. Another possible field for research is expanding ElStorM's storage mechanism towards a representation of demand-side measures like load shifting or interruptible load.

[21] Compare the European Technology Platform for the Electricity Networks of the Future, http://www.smartgrids.eu, last accessed 14 January 2009.

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