Modeling Strategic Electricity Storage: The Case of Pumped Hydro Storage in Germany

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We study the strategic utilization of storage in imperfect electricity markets. We apply a game-theoretic Cournot model to the German power market and analyze different counterfactual and realistic cases of pumped hydro storage. Our main finding is that both storage utilization and storage-related welfare effects depend on storage ownership and the operator's involvement in conventional generation. Strategic operators generally under-utilize owned storage capacity. Strategic storage operation may also lead to welfare losses, in particular if the total storage capacity is controlled by an oligopolistic generator that also owns conventional generation capacity. Yet in the current German situation, pumped hydro storage is not a relevant source of market power.

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1. INTRODUCTION

Interest in electricity storage is increasing. Grid storage capacity is expected to grow in many countries, mainly driven by the need to integrate large amounts of fluctuating renewable energy into electricity systems. Bulk electricity storage is primarily achieved through pumped hydro storage. However, other storage technologies might be increasingly used in the future.

Yet economic research on electricity storage is limited. In particular, energy economists pay little attention to the issue of strategic operation of pumped storage facilities. While the strategic dispatch of self-replenishing hydro reservoirs is studied to some extent, there is a research gap on the strategic utilization of storage facilities which can be actively charged and discharged, in the form of, for example, pumped hydro plants. In addition, the interrelation of storage operations with strategic conventional electricity generation scheduling is not yet studied.

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In this article, we examine the issue of strategic storage utilization with a model-based analysis, applied to the German power market and the case of pumped hydro storage. We develop the game-theoretic electricity market model ElStorM,[1] which allows analyzing strategic storage utilization in an oligopolistic market environment with imperfectly competitive generators. The strategic interaction between the firms is modeled as a Cournot oligopoly. Our analysis illustrates the dynamic interaction of profit-maximizing firms' decisions on strategic storage and the dispatch of other generation capacity. More specifically, we study the impacts of different storage operators on both storage utilization and welfare outcomes by drawing on various cases in which storage is assigned to different players. Storage players may either be merchant storage operators without involvement in conventional generation, or they may hold other generation capacity, as well. They may also differ in their ability to exert market power both regarding storage and conventional generation, i.e. to anticipate the effect of production decisions on market outcomes. Furthermore, the remaining generators in the market may be perfectly competitive or oligopolistic.

Our main finding is that storage utilization and storage-related welfare effects depend on the storage owner and its ability to exert market power. Strategic storage operators generally under-utilize their capacity. Regarding welfare, storage has two important effects. On the one hand, it generates arbitrage profits for the storage operator. On the other, it has a smoothing effect on market prices, which may decrease generators' surpluses and increase consumer rents. As a result, we find that the introduction of storage decreases total producer surplus. Yet an increase in consumer surplus outbalances the decrease in producer surplus. Overall welfare thus increases in all modeled cases, although the magnitude of the effect depends on storage ownership. Welfare gains from storage in an oligopolistic market environment are lowest if the total storage capacity is controlled by a single strategic generator. The most realistic cases show that, currently, strategic pumped hydro storage utilization is very unlikely to be a relevant source of market power in Germany.

The article is structured as follows. First, we discuss the relevant literature. Section 3 introduces the model ElStorM. Section 4 provides data and lists the different cases of storage operation by various strategic and non-strategic players. Section 5.1 analyzes the general effects of electricity storage on market outcomes. In 5.2, we analyze how storage utilization depends on different players. Section 5.3 studies welfare effects in detail. The last section summarizes and concludes.

2. LITERATURE

The literature on the topic of market power in restructured electricity markets is growing substantially. Green and Newbery (1992) made a seminal

1. ElStorM stands for Electricity Storage Model.

contribution with their case study of the British market. They found that the Nash equilibrium in supply schedules of two dominant generators might imply high markups on marginal costs and substantial deadweight losses. Several more recent articles empirically test different theories of oligopolistic firm behavior by competitive benchmark analyses. For example, Borenstein et al. (2002) perform such an analysis for the Californian power market from 1998 to 2000 and find substantial mark-ups on wholesale electricity prices in high demand periods due to market power exertion. Puller (2007) extends this analysis by studying different types of oligopoly pricing. Hortaçsu and Puller (2008) perform a comparable analysis for the bidders in the Texas hourly balancing market. Mansur (2008) develops an alternative econometric approach which accounts for intertemporal production constraints like start-up costs. An application to the American PJM market indicates that historic prices have exceeded competitive benchmarks, but not as much as other methods suggests. Weigt and Hirschhausen (2008) develop a competitive benchmark model for Germany that also includes start-up constraints and find that market prices in 2006 were above competitive levels.

Beyond retrospective empirical analyses, market power also plays an important role in bottom-up numerical electricity market modeling. Ventosa et al. (2005) review and classify various electricity market model types and show that partial equilibrium models are most suitable for market power analyses as these are able to deal with simultaneous profit maximization problems of all players in the market. These are either based on Cournot or Bertrand competition (quantity or price competition), or 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 bound by Cournot and Bertrand outcomes. Puller (2007) and Bushnell et al. (2008) provide empirical support that Cournot pricing may be the most reasonable assumption for electricity market modeling. Andersson and Bergman (1995) are among the first to implement the Cournot approach in a numerical model of the Swedish market. Borenstein and Bushnell (1999) perform a Cournot analysis for the Californian market, assuming three Cournot competitors and a competitive Fringe. Lise et al. (2006) apply a similar model to the Northwestern European electricity market and quantify how market power exertion by large producers harms consumers in different scenarios. Lise et al. (2008) find that scarce European cross-border transmission capacity and dry weather lead to additional market power exertion potentials. As for Germany, Traber and Kemfert (2009; 2010) use game-theoretic Cournot models to study the impact of German support for renewable electricity generation on prices, emissions, and profits as well as the impact of wind power on incentives for investments in thermal power plants. Our model, which is described in Section 3, implements strategic Cournot pricing in a numerical, game-theoretic partial equilibrium framework and thus follows the strand of literature mentioned above. We extend the methodological scope of the cited models by including both an hourly time resolution and intertemporal constraints.

The research reviewed so far does not include storage. Interest in modeling storage and its strategic interaction with conventional generation has recently increased. However, the strand of literature largely deals with hydro reservoirs only and not with pumped storage. There is a substantial difference between the two technologies. Hydro reservoirs are self-replenishing because of natural inflows. As opposed to thermal generation, a strategic dispatch of hydro reservoirs is not related to withholding capacity as such, but rather to strategically allocating hydro resources over different time periods. In contrast, pumped hydro storage operators may not only strategically decide on storage outputs, but also on *inputs*. This may complicate strategic decision-making and may also lead to additional market power potentials.

Rangel (2008) provides a literature review dealing with strategic scheduling of hydro reservoirs. He shows that players in hydro-dominated markets, like New Zealand, Norway and some South American countries, may exploit market power potentials related to hydrological conditions, reservoir levels and inflow probabilities. Scott and Read (1996) were among the first to study gaming by mixed hydro-thermal firms by applying a Cournot duopoly model to the New Zealand market. Borenstein and Bushnell (1999) use a Cournot oligopoly model to analyze the potential for market power exertion in the Californian power market before deregulation. They 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. He finds that a monopolist generates too much electricity from hydro resources in the first period compared to the competitive solution, which leads to welfare losses. Garcia et al. (2001) develop a simplified oligopoly model with dynamic Bertrand competition of hydro generators and find welfare losses from reservoir-related market power exertion. Bushnell (2003) develops a multi-period Cournot model of hydrothermal coordination in the Western United States in a mixed complementarity framework. He finds that strategic firms increase profits compared to competitive ones by shifting more hydro production toward off-peak periods. The model developed in this paper can be interpreted as an extension of Bushnell's approach to pumped hydro storage.

In contrast to the aforementioned hydro reservoir literature, other studies explicitly deal with pumped hydro or comparable large-scale storage technologies. Yet these largely neglect market power issues. For example, Crampes and Moreaux (2010) theoretically analyze how firms' combined decisions on pumped hydro storage and thermal plants can lead to cost savings and net social welfare gains under the assumption of perfect competition. Sioshansi et al. (2009) analyze arbitrage profits to be captured by the owner of a price-taking storage device in the PJM market between 2002 and 2007 with an optimization model. As storage decreases peak prices and increases off-peak prices, they find that consumers benefit from storage while producers lose. In section 5, we show that these findings also apply in an oligopolistic market. Sioshansi (2010) models the strategic utilization of large-scale storage facilities by different owners and the effects on storage utilization and welfare. While consumers overuse their storage capacity, merchant storage operators and generators tend to underuse it. The author finds that private incentives for storage operation might not be aligned to the social optimum and that merchant storage operators should be encouraged from a welfare perspective. The model developed in this article shows some similarities to Sioshansi (2010), but is more refined due to the inclusion of intertemporal constraints. Even more importantly, we are able to explicitly model the interaction of strategic storage and thermal generation decisions in an oligopolistic market structure.

Summing up, our model and its application to the case of pumped hydro storage in Germany contribute to the literature in several ways. First, it increases the understanding of strategic storage utilization as it not only deals with the strategic allocation of self-replenishing hydro resources, but also with firms' strategic decisions on storage loading. We furthermore model the interaction of different players' combined decisions on thermal generation, storage loading, and discharging. We explicitly consider the price-smoothing effects of storage and related welfare impacts. Finally, we are able to compare the potential for exerting market power that is associated with pumped hydro storage operations to the market power potentials related to conventional generation. The article thus complements the body of literature that deals with the possibilities of market power exertion in power markets.

3. THE MODEL

We introduce the game-theoretic electricity market model, ElStorM. Firms maximize profits by deciding on hourly electricity generation levels of different conventional technologies as well as on hourly pumped hydro storage loading and discharging. In doing so, players face a range of technical constraints. The model formulation allows us to include strategic players that exert market power. The model solution represents a Cournot-Nash equilibrium. In contrast to earlier applications of Cournot approaches in electricity market modeling, ElStorM includes not only electricity storage, but also an hourly time resolution and intertemporal constraints for both conventional generation technologies and pumped storage. These features are essential for analyzing strategic storage operation. Table 5 in the Appendix 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 conventional technologies $i \in I$, for example, coal or natural gas. Firms also decide on hourly loading $stin_{f,t}$ and discharging $stout_{f,t}$ of pumped hydro storage. Each player faces the following constrained maximization problem. Player's indices f are omitted in order to improve readability.

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

s.t. $$x_{i,t} - \bar{x}_i \leq 0, \ \forall i,t \qquad (\lambda_{i,t}^{gen}) \tag{1b}$$

$$x_{i,t} - x_{i,t-1} - \xi_i^{up} \bar{x}_i \leq 0, \ \forall i,t \qquad (\lambda_{i,t}^{rup}) \tag{1c}$$

$$x_{i,t-1} - x_{i,t} - \xi_i^{down} \bar{x}_i \leq 0, \ \forall i,t \qquad (\lambda_{i,t}^{rdo}) \tag{1d}$$

$$stout_t - \overline{st}^{out} \leq 0, \ \forall t \qquad (\lambda_t^{stout}) \tag{1e}$$

$$stin_t - \overline{st}^{in} \leq 0, \ \forall t \qquad (\lambda_t^{stin}) \tag{1f}$$

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

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

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

$$stin_t, stout_t \geq 0, \ \forall t \tag{1j}$$

The objective function (1a) represents player f's profit function. It adds up revenues from selling electricity generated by conventional technologies $\sum_{i \in I} p_t x_{i,t}$ and by pumped storage $p_t stout_t$ for 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, $\sum_{i \in I} vgc_i x_{i,t}$, which represent fuel prices, emission prices, technology-specific generation efficiency and other variable costs. For reasons of consistency, variable costs of storage operation $vstc \cdot stout_t$ are also included, which are assigned to storage loading and assumed to be constant for every unit of electricity generated.[2] Furthermore, (1a) includes the costs $p_t stin_t$, 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. Firms thus face costs equal to the market price p_t for each unit of electricity stored at time t.

Condition (1b) represents maximum generation capacity restrictions. For each conventional technology i, a firm's actual power generation cannot exceed its installed capacity. (1c) and (1d) are intertemporal constraints on conventional generation. (1c) is a ramping up restriction: between two subsequent hours, electricity generation of a particular technology can only be increased to a certain degree, depending on a technology-specific parameter ξ_i^{up} and the total installed

2. It does not matter if variable storage costs are assigned to storage loading or discharging.

capacity. ξ_i^{up} takes on values between 0 and 1. For example, ξ_i^{up} is relatively small for inflexible nuclear power, but assumes the value 1 for perfectly flexible technologies. Likewise, condition (1d) represents technology-specific ramping down restrictions. Note that we draw on a stylized concept of ramping constraints in this context. Here, the term "ramping" does not refer to individual power plants, but to a firm's total capacity of a given technology. In the real world, thermal power plants face both start-up and ramping constraints. They cannot start up or shut down instantaneously due to thermal restrictions on minimum on- and off-times. For example, it takes several hours to get a coal plant fully operational. Once a plant is started up, there are still ramping constraints in the sense that output cannot instantly change. From a modeling perspective, it would be extremely challenging to fully represent these constraints. A detailed bottom-up approach would require to model individual power plants and include binary on/off variables, start-up and ramping restrictions for each single plant. The resulting mixed-integer unit commitment problem would invalidate the Karush-Kuhn-Tucker conditions for each player's optimization problem. Solving the resulting Nash-equilibrium problem would be very hard, if not impossible. We thus refrain from modeling individual power plants and rather focus on a firm's cumulative installed capacity of a given technology. Start-up and ramping constraints are represented by an aggregated ramping restriction that is not applied to single power plants, but to the whole capacity of a player's generation technology.

Conditions (1e) to (1h) constrain pumped hydro storage decisions.[3] (1e) resembles (1b) and states that the power 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 in any period t. In other words, the conditions represent limited generation and pumping capacity of pumped hydro plants. (1g) and (1h) represent reservoir restrictions, i.e. energy storage capacity. (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.[4] 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. As 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, because it is by design a very

3. Note that pumped hydro storage facilities do not directly store electricity, but rather the potential energy of water by pumping water through a pipe into an uphill reservoir. Later on, the stored energy can be retrieved by letting the water run downhill again, where it drives a generator that produces electricity. This process is characterized by mechanical and electrical losses, which lead to round-trip efficiencies of around 0.75 for average pumped hydro storage plants. That is, for each MWh of electricity used for pumping water into the reservoir, only 0.75 MWh can be retrieved again later.

4. The model could be extended by including additional natural inflows to the reservoir.

flexible technology. Conditions (1i) and (1j) ensure non-negativity of the variables $x_{i,t}$, $stin_t$ and $stout_t$.

Equation (2) defines total electricity supply X_t as the total amount of electricity generated by all firms by conventional technologies, plus generation from pumped storage, minus storage loading. The market clearing condition (3) makes sure that total supply equals demand in every period. 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, which is assumed to be time-invariant.

$$X_t = \sum_{f \in F} \left[\sum_{i \in I} x_{f,i,t} + stout_{f,t} - stin_{f,t} \right], \ \forall t \tag{2}$$

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

Equations (1a)–(1j) have to be solved for all players, whereas (3) links the problems of the individual players together. We formulate the optimization program as a mixed complementarity problem (MCP), which is the suitable formulation for this type of problem. The definition of an 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, an 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 (2), solve for p_t and insert the expression into (1a). We then derive the KKT optimality conditions (5a)–(5k), which are listed in the Appendix. The KKT conditions form our nonlinear mixed complementarity equation system. It consists of more than 80,000 variables and equations in our application. It is implemented in the General Algebraic Modeling System (GAMS), including real data on generation capacity, costs and demand from the German electricity market (Section 4). The problem is solved numerically 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 (4a) by integrating the demand function from 0 up to the actual quantity and subtracting the amount actually paid.[5] Producer rent for each player is calculated according to equation (4b) by summing up revenues and subtracting costs.

5. 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,

$$crent_t = \int_0^{X_t} p0_t \left(\frac{x}{d0_t}\right)^{-\frac{1}{\sigma}} dx - p_t X_t, \ \forall t \tag{4a}$$

$$prent_{f,t} = \sum_{i \in I} x_{f,i,t}(p_t - vgc_i) + stout_{f,t}(p_t - vstc) - stin_{f,t} p_t, \ \forall f,t \tag{4b}$$

4. MODEL APPLICATION

We apply the model to the German electricity market during a typical winter week. A winter week is most suitable for analyzing storage in the German electricity market, as we find the highest peak loads and the highest prices in this season. We include three additional days both before and after the week in order to establish meaningful storage patterns that take into account the lower demand levels around the weekends. Thus, we model 13 days or 312 consecutive hours. Hourly data on German reference demand $d0_t$ and reference prices $p0_t$ is taken from the European Energy Exchange EEX for 16 January to 28 January 2009. We assume a price elasticity of demand of $\sigma = 0.45$. Calibrating the model with this value allows to replicate the reference demand and price levels very well. The value is also in line with other models (Borenstein and Bushnell 1999; Traber and Kemfert 2009). For reasons of simplicity and traceability, σ is assumed to be time-invariant. We perform sensitivity analyses for alternative assumptions on σ of 0.3 and 0.6.

We include six players, among them the four large strategic firms E.ON, RWE, Vattenfall, and EnBW. Combined, these firms hold more than 80% of total German generation capacity. The remaining generation capacity is assigned to a competitive generation firm named “Fringe”. In addition, we include a merchant storage player “NoGen” without any conventional generation capacity, which only engages in storage operations. As for conventional generation technologies, we include nuclear, lignite, hard coal, natural gas, oil, and hydro power. Natural gas includes combined cycle, steam and gas turbines. Hydro power includes run-of-river and other hydroelectric plants, but excludes pumped storage. Table 1 lists the conventional generation capacity available to different players. Data is derived from the database used by Traber and Kemfert (2009). It is adjusted with technology-specific plant availabilities in order to reflect regular maintenance and outages. We exclude other renewable technologies like wind power since its generation in Germany is currently not driven by wholesale market prices, but by technology-specific feed-in tariffs. Accordingly, it is only indirectly related to the price formation at EEX.

the choice of the lower integration limit is irrelevant as we do not look at absolute levels of consumer rent, but only at rent changes between different scenarios.

Table 1: Generation and Storage Capacity

	EnBW	E.ON	RWE	Vattenfall	Fringe	NoGen
Available conventional generation capacity in MW:						
Nuclear	3,974	7,553	3,496	1,402	946	0
Lignite	398	1,302	8,494	7,201	403	0
Hard coal	1,570	5,833	2,615	979	3,604	0
Natural gas	686	2,543	1,959	1,382	4,302	0
Oil	103	348	5	152	127	0
Hydro	299	1,055	447	0	625	0
Installed pumped hydro storage capacity:						
Storage loading and discharging rate in MW	1,006	1,017	1,023	2,893	456	0
Storage capacity in MWh	7,200	6,790	6,959	17,141	2,202	0

Table 1 also includes the pumped hydro storage capacity currently installed in Germany.[6] The total pumped hydro generation capacity amounts to around 6.4 GW. A literature survey shows that most pumped storage plants have roughly the same capacity for loading and discharging. We thus assume $\overline{st}_f^{out} = \overline{st}_f^{in}$. Note that these values refer to the power of turbines and pumps, and are accordingly measured in MW. In contrast, the installed storage capacity, $\overline{st}_f^{cap}$, refers to the volumes of the storage reservoirs and is thus measured in MWh. We assume that only 80% of the capacity shown in Table 1 is available for arbitrage purposes. In doing so, we reflect outages and regular maintenance, as well as the fact that some storage capacity is reserved for backup and black start purposes.

Table 2 lists ramping parameters and variable generation costs for conventional generation technologies. As explained in Section 3, the ramping parameters do not refer to single power plants, but to a player's overall capacity of the respective technology. Since bottom-up data on such aggregated ramping constraints does not exist, we draw on effective generation as reported to EEX over the course of a whole year. For a representative sample of weeks, we determine the maximum output changes between two consecutive hours for each technology

6. Sources include dena (2008) and company information provided by EnBW, E.ON, RWE, Vattenfall and Schluchseewerk. In addition to the domestic capacity listed in Table 1, German grid operators also utilize pumped hydro storage plants in neighboring countries to some extent. Yet for reasons of traceability and consistency, we only draw on domestic capacity. Note that 'Schluchseewerk' is a large German pumped hydro storage operator that is owned jointly by EnBW and RWE, each with a 50% share. An interview with a company representative showed that 50% of the company's storage capacity is operated for EnBW and another 50% for RWE. Accordingly, the total 'Schluchseewerk' capacity is assigned to EnBW and RWE with 50% each.

Table 2: Parameters for Conventional Generation Technologies

	Nuclear	Lignite	Hard Coal	Natural Gas	Oil	Hydro
ξ_i^{up}	0.05	0.07	0.22	0.28	0.68	0.22
ξ_i^{down}	0.10	0.06	0.18	0.26	0.72	0.19
vgc_i in €/MWh	10	25	30	40	50	10

and relate this value to the overall installed capacity of the respective technology. This results in the values listed in the table. For example, the data shows that the nuclear power plant fleet is usually ramped up only 5% of the total capacity within one hour and 10% down. While it may be technically feasible to achieve higher ramping rates in case of extreme events, our empirically founded ramping parameters represent the technology-specific generation flexibility for respective technologies very well.[7]

Table 2 also lists variable generation costs, which reflect fuel and other operational costs as well as emission costs. These are estimated drawing on dena (2005), Wissel et al. (2008), as well as data provided by EEX and the International Energy Agency. The costs of operating pumped hydro storage mainly consist of opportunity costs, $p_t stin_t$, and efficiency losses. We assume an average round-trip storage efficiency of $\eta_{st} = 0.75$ (dena 2008). That is, for each MWh that is loaded into pumped storage facilities, only 0.75 MWh can be retrieved again later. Because of a lack of reliable data, we neglect variable storage operation costs $vstc$. This simplifying assumption is not important as the variable costs of operating a pumped hydro storage plant (other than $p_t stin_t$) may indeed be close to zero. Nonetheless, this assumption might lead to slightly over-optimistic arbitrage profits.

Overall, we study 20 different cases, which are listed in Table 3. All cases draw on the same distribution of conventional generation capacity among the market players, as shown in Table 1. In contrast, the scenarios vary with respect to the existence and distribution of pumped hydro storage capacity among different players, which may or may not own other generation capacity. For example, in the counterfactual PC1 case, the total pumped hydro storage installed in Germany is completely assigned to the operator NoGen, which does not own any other generation assets. In PC4, the total storage capacity is distributed among the German generators in a realistic way according to Table 1. In other words, cases 1–3 and 5–7 (both PC and IC) have a counterfactual character as the total

7. In the first period, we relax the ramping restrictions on conventional generation in order to avoid distortions. We furthermore assume that the storage facilities are empty in period 1. We do not restrict storage levels in the final period, which in an optimal solution will result in an empty reservoir in the last period.

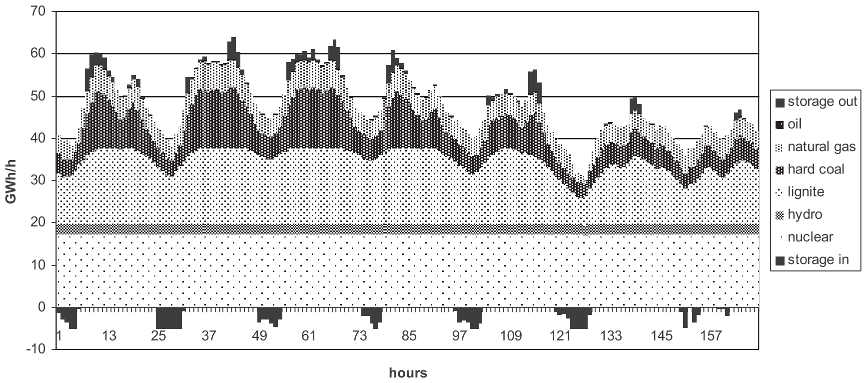
Table 3: Overview of Scenarios

Case	Conventional generation	Storage assigned to	Storage operation
PCBase	Perfect competition	—	—
PC1	Perfect competition	NoGen only	Non-strategic
PC2	Perfect competition	Fringe only	Non-strategic
PC3	Perfect competition	E.ON only	Non-strategic
PC4	Perfect competition	Real-world distribution	All non-strategic
PC5	Perfect competition	NoGen only	Strategic
PC6	Perfect competition	Fringe only	Strategic
PC7	Perfect competition	E.ON only	Strategic
PC8	Perfect competition	Real-world distribution	All strategic
ICBase	Imperfect competition	—	—
IC1	Imperfect competition	NoGen only	Non-strategic
IC2	Imperfect competition	Fringe only	Non-strategic
IC3	Imperfect competition	E.ON only	Non-strategic
IC4	Imperfect competition	Real-world distribution	All non-strategic
IC5	Imperfect competition	NoGen only	Strategic
IC6	Imperfect competition	Fringe only	Strategic
IC7	Imperfect competition	E.ON only	Strategic
IC8	Imperfect competition	Real-world distribution	EnBW, E.ON, RWE and Vattenfall strategic, Fringe non-strategic
EONBase	E.ON strategic	—	—
EON7	E.ON strategic	E.ON only	Strategic

storage capacity is concentrated in the hand of a single player. Note that all cases (except the baselines) assume the same overall storage capacity, but differ with respect to its distribution among firms.

The cases further differ with respect to market power assumptions. Storage operators may decide on storage loading and discharging in a strategic or in a non-strategic way. This means that $\theta_f^{st} = 1$ or 0 in the first order conditions (Appendix). Moreover, we make different assumptions on the general structure of the German electricity market. It may either be perfectly competitive (PC1-8) or an imperfectly competitive oligopoly with four strategic generators (IC1-8). That is, $\theta_f^{gen} = 0\ \forall f$ for the IC cases, but $\theta_f^{gen} = 1$ for the four largest generators in the PC cases. For illustrative purposes, we also include two additional counterfactual cases in which only the largest generating firm, E.ON, has market power regarding conventional generation. We then assign the storage capacity exclusively to E.ON, assuming that the player also utilizes it in a strategic way. For reasons of consistency, we label these cases EONBase and EON7. Table 6 in the Appendix summarizes the market power parameters θ_f^{gen} and θ_f^{st} for all scenarios. The different cases allow us to analyze the interrelation of storage and other generation decisions in a competitive or an oligopolistic market environment in depth. The most realistic case may be IC8, if one assumes oligopoly pricing on

Figure 1: Conventional Generation and Storage Utilization over One Week in IC1



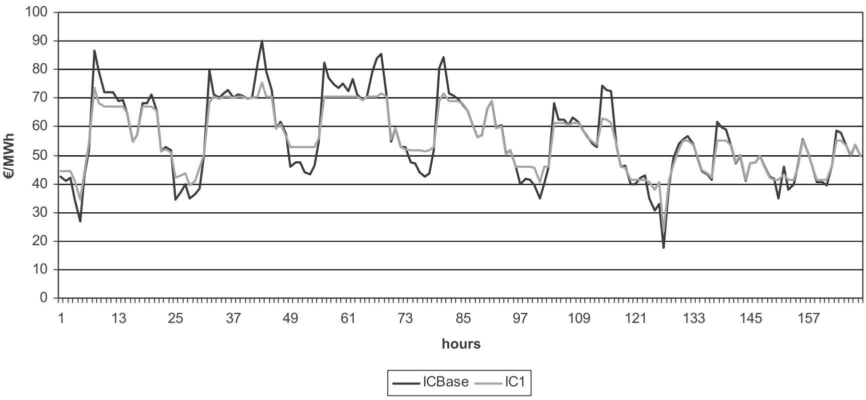
the German generation market. Other cases are less realistic, but interesting from an analytical point of view. For example, oligopolistic generating firms anticipate the price reactions of their conventional generation decisions in IC4, but not of their storage decisions. This may not be realistic, but the results are very illustrative.

5. RESULTS

5.1. General Effects of Introducing Storage

We illustrate the general effects of introducing storage to the German market by looking at the stylized IC1 case, which assumes an oligopolistic generation market. We however make the counterfactual assumption that all German storage capacity is in the hands of one or several merchant storage operators that carry out storage operations in a non-strategic way. As the merchant storage player's decisions are not distorted by any involvement in the conventional generation business, this case lends itself to illustrative purposes. Figure 1 shows the storage operation pattern in IC1 in the context of overall generation for a whole week (the 7 days in the middle of the 13 days modeled). A characteristic pattern of daily load peaks and nightly off-peak periods is visible. Nuclear and run-of-river hydro power are always generating due to low marginal costs. Lignite generation is principally running during weekdays and is, to some extent, ramped down during off-peak periods. Hard coal and natural gas provide medium and peak load, whereas oil serves peak loads only. Looking at pumped hydro storage, we find that a profit-maximizing storage operator loads storage during the night and discharges it during the daily peak hours. As a result, conventional generation is smoother than in the baseline without storage. This fact is reflected by the number of binding ramping constraints, which decreases from 1071 in ICBase to 945 in the IC7 case.

Figure 2: Prices over One Week in ICBase and IC1



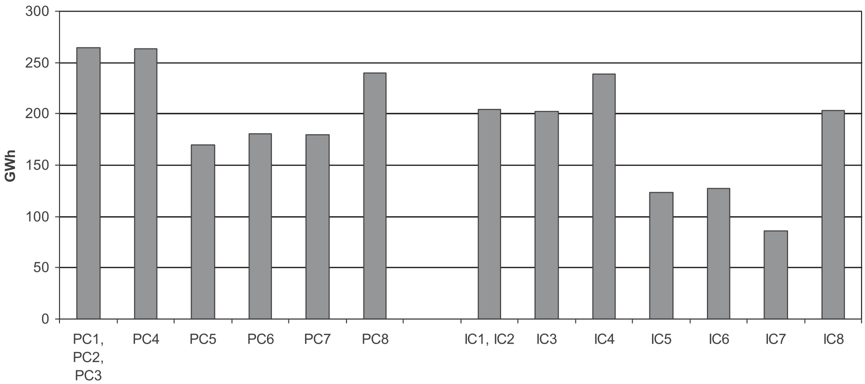
Buying electricity during inexpensive off-peak periods and selling it again during high-price peak periods allows the merchant storage operator to make arbitrage profits of around €2 million over 13 days. Extrapolating this value results in a yearly profit of around €58 million. Yet the introduction of storage smoothes electricity prices compared to the baseline due to additional demand in off-peak periods and additional supply in peak periods. Figure 2 shows that off-peak prices increase, while peak load prices decrease. This price-smoothing effect of storage negatively affects the producer rents of electricity generating firms, which benefit from peak prices. We find that generators' losses outweigh the merchant storage operator's profits. Overall producer surplus thus declines. For consumers, the opposite is true: their surplus increases because consumers benefit more from lower peak prices than they are harmed by higher off-peak prices. As the increase in consumer rent outweighs the decrease in producer rent, overall welfare increases.[8] Additional details on welfare results are provided below.

5.2. Storage Utilization of Different Players

Figure 3 shows that storage utilization is highest in the PC1-4 cases among all model runs. Perfect competition for both storage utilization and conventional generation thus leads to the highest possible utilization of existing storage capacity. Among the cases with perfectly competitive generators (PC1-8), storage utilization is low in the strategic storage cases PC5-7, in which the whole storage capacity is in the hands of a single strategic operator. In these cases, the players strategically under-utilize the storage capacity in order not to excessively

8. The results are in line with the findings by Sioshansi et al. (2009), which apply a strategic optimization model to the PJM market.

Figure 3: Total Storage Output over 13 Days in Different Cases



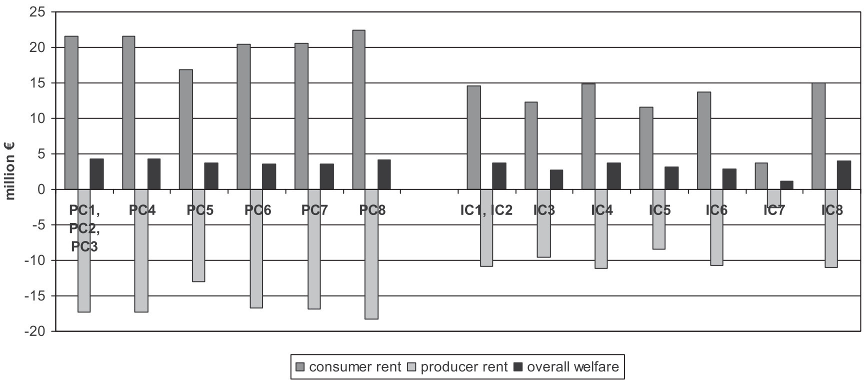
smooth prices, which results in higher arbitrage gains. The strategic case PC8 provides an exception to this finding. In this case, storage is distributed among several strategic operators, which makes it difficult for a single operator to withhold storage capacity. Storage utilization is thus nearly as high as in the non-strategic cases.

Looking at the cases that assume oligopolistic generators, we find that storage utilization is always lower than in the respective cases with perfectly competitive generators. Storage utilization is highest in the IC4 case, in which storage is distributed among the generators and operated in a non-strategic way. Storage utilization in the non-strategic IC1-3 and the strategic IC8 cases is nearly equal. As in the PC cases, we find that the distribution of the total storage capacity among several strategic operators (IC8) leads to storage utilization comparable to the non-strategic cases. If the storage capacity is in the hands of a single strategic operator (IC5-7), storage utilization is substantially lower. This effect is much more pronounced than in the previously discussed PC5-7 cases. In particular, concentrating the total storage capacity in the hand of a strategic operator, which also holds large strategic conventional generation capacity leads to a substantial under-utilization (IC7). Summing up, independent of our assumptions on the market power of generators, strategic storage operation always results in a lower use of the storage capacity than non-strategic operation. The under-utilization of storage capacity is more pronounced in an oligopolistic generation market and particularly high if the total storage capacity is concentrated with a single strategic generator.

5.3. Welfare Results

Figure 4 shows storage-related welfare effects over the 13 modeled days. It indicates the differences between the respective storage case and the baseline

Figure 4: Comparison of Welfare Results: Differences to Respective Baselines over 13 Days



runs without storage. In all cases, storage increases overall welfare and consumer rents, whereas total producer rent decreases. In the following, we analyze the welfare results in more detail.

5.3.1. Producer rents

Total producer surplus decreases after introducing storage in all cases. Table 4 shows that this is not necessarily the case for individual producer surpluses. A storage operator's surplus may increase after introducing storage due to additional arbitrage profits. A profit-maximizing merchant storage operator, which owns no conventional generation capacity, always makes positive profits from utilizing storage. Arbitrage profits are even larger if storage is operated strategically (compare PC1, PC5 and IC1, IC5). Yet the surpluses of all other generators, which do not participate in storage activities, decrease because they suffer from the price-smoothing effect of storage. As the losses of other players outweigh the storage operator's arbitrage gains, overall producer rent decreases compared to the baseline – a general results that holds for all model runs.

Looking at other storage cases, however, we find that a storage operator that also owns conventional generation capacity may be worse off after introducing storage compared to the baseline (PC2-4, PC6-8, IC3-4, and IC7-8). At first glance, this is a surprising result, as profit-maximizing players could decide to not utilize any storage capacity. Another intriguing finding is that strategic storage operation sometimes leads to even bigger losses for storage operators than the respective non-strategic storage case (PC8 vs. PC4, IC8 vs. IC4). Three effects explain these seemingly counter-intuitive results. They are related to the first-order conditions of the optimization problem listed in the Appendix. First, players imperfectly foresee their decision's impact on market prices in several cases, which results in a lack of coordination between the maximization of arbitrage

Table 4: Producer Rent Differences to Respective Baselines over 13 Days in Million €. Bold numbers indicate storage operators

Cases with perfectly competitive generators								
	PC1	PC2	PC3	PC4	PC5	PC6	PC7	PC8
EnBW	–2.13	–2.13	–2.13	**–1.67**	–1.72	–2.14	–2.17	**–1.77**
E.ON	–5.84	–5.84	**–3.08**	**–5.39**	–4.68	–5.73	**–2.81**	**–5.70**
RWE	–5.13	–5.13	–5.13	**–4.67**	–4.15	–5.19	–5.27	**–5.04**
Vattenfall	–3.37	–3.37	–3.37	**–2.14**	–2.72	–3.40	–3.45	**–2.36**
Fringe	–3.61	**–0.85**	–3.61	**–3.43**	–2.83	**–0.26**	–3.21	**–3.43**
NoGen	**+2.76**	0.00	0.00	0.00	**+3.05**	0.00	0.00	0.00
Total	–17.32	–17.32	–17.32	–17.31	–13.05	–16.73	–16.91	–18.30
Cases with oligopolistic generators								
	IC1	IC2	IC3	IC4	IC5	IC6	IC7	IC8
EnBW	–1.27	–1.27	–1.02	**–0.87**	–1.19	–1.49	–0.36	**–0.89**
E.ON	–4.11	–4.11	**–2.21**	**–3.91**	–3.28	–3.86	**–0.23**	**–4.19**
RWE	–3.53	–3.53	–3.02	**–3.25**	–2.91	–3.51	–0.87	**–3.07**
Vattenfall	–2.38	–2.38	–1.88	**–1.67**	–2.00	–2.47	–0.57	**–0.96**
Fringe	–1.70	**+0.37**	–1.39	**–1.45**	–1.67	**+0.58**	–0.53	**–1.95**
NoGen	**+2.06**	0.00	0.00	0.00	**+2.62**	0.00	0.00	0.00
Total	–10.92	–10.92	–9.52	–11.15	–8.42	–10.76	–2.56	–11.07

profits and generation-related profits. For example, the Fringe player in PC2 neither adjusts its generation decisions to the price-smoothing effect of storage, nor does it take into account its conventional generation when deciding on storage inputs and outputs ($\theta^{st}_{Fringe} = \theta^{gen}_{Fringe,i} = 0$ in equations 5a–5c). Whereas the Fringe player makes positive arbitrage profits in PC2, its profits in conventional generation decrease even more due to the price-smoothing effect of storage. The same argument holds for PC2-4. In the cases PC6-8, storage operators are able to anticipate the price-effects of storage operation when deciding on storage inputs and outputs as well as on conventional generation ($\theta^{st}_f = 1$). However, players in these cases are assumed not to take into account the price effects of their conventional generation decisions ($\theta^{gen}_f = 0$). Accordingly, the $\vartheta^{gen}_{f,i,t}\theta^{gen}_f$ terms in the first order conditions are zero while $\vartheta^{out}_{f,t}\theta^{st}_f$ and $\vartheta^{in}_{f,t}\theta^{st}_f$ are positive. In general, $\vartheta^{in}_{f,t}$ is larger than $\vartheta^{out}_{f,t}$, as storage is loaded in off-peak periods, but discharged in peak periods. Players may thus be better of than in the non-strategic storage cases PC2-4, but still worse off than in PCBase.

Second, other strategic generators adjust their production to storage-related price effects. Note that the four strategic generators are able to take into account market price reactions to their conventional generation decisions in the cases IC1-8, as well as to storage decisions in IC5-8 (compare Table 6). For example, the storage operator E.ON is able to foresee the price reactions to its conventional generation decisions in IC3, and also of its storage decisions in IC7. Yet storage operators' surpluses still decrease compared to the baseline in IC3-4 and IC7-8. In these cases, the three other oligopolistic players adjust generation to the new market situation. For example, in IC7, EnBW, RWE and Vattenfall increase their generation levels during E.ON's storage loading periods and slightly decrease them during storage discharging periods, compared to ICBase. As a result, the players that are not involved in storage operations manage to diminish storage-related producer rent losses. Accordingly, their surpluses in IC1-3 and IC5-7 are higher compared to the respective PC cases, in which they are not able to adjust their generation strategically. E.ON in turn plays an optimal strategy given its rivals' generation decisions. The other oligopolistic generators' strategies, however, harm E.ON in such a way that even strategic storage operation leads to a small loss of surplus compared to the baseline (IC7). Accordingly, E.ON is not able to benefit from storage in our model—neither in a perfectly competitive, nor in an oligopolistic market.[9] An additional model run shows that E.ON would only be able to benefit from storage if it was the only strategic generator in the market, i.e. if the other three generators were not able to adjust their generation. The results of this additional run (EON7) are listed in Table 7 in the Appendix.

There is a third effect which explains the low producer rents of storage operators in the cases PC8 and IC8, in which the total storage capacity is distributed among all generators as in the real world. Overall, producers suffer heavily from storage in these cases because they face a prisoners' dilemma. Producers would be better off if all agreed not to utilize any storage capacity, however, such behavior does not represent a stable Nash-Cournot solution. Each player has an incentive to deviate from this point by using its storage capacity to make some arbitrage profits. The resulting price-smoothing effect harms all other generators, which, in turn, also have an incentive to make arbitrage profits. In the end, cases 4 and 8 (both PC and IC) result in high overall storage utilization with according price-smoothing, such that all generators are worse off than in the respective baselines.

Finally, our results suggest that pumped hydro storage investments are not attractive for incumbent German generating firms. In the cases with realistic distribution of storage among generators, we find that producer rents are always lower than in the baseline case without storage, irrespective of our assumptions on market imperfections (PC4, PC8, IC4, and IC8). Generators are harmed by

9. Note that E.ON's producer surplus is still much higher in the strategic IC7 compared to the non-strategic IC3. Besides, E.ON is better off in IC7 compared to not using its storage capacity at all. This can be shown with an additional model run in which E.ON's storage utilization is exogenously fixed to zero. Finally, a sensitivity analysis shows that the finding depends on demand elasticity: Under the assumption of $\sigma = 0.6$, E.ON is able to make a positive profit in the IC7 case.

the price-smoothing effect of storage, which diminishes their surpluses from conventional generation. In contrast, merchant storage operators, which are not involved in conventional generation, make positive arbitrage profits in the counterfactual cases. The same is true for non-strategic generating firms in an oligopolistic market environment (IC2), although to a much lower extent. Pumped storage investments may thus only be attractive for merchant operators and generating firms without market power.[10]

5.3.2. Consumer rents

Figure 4 indicates that storage has a positive effect on consumer surplus in all modeled cases. Consumer rent is particularly high in those cases in which producer surplus is low, and vice versa. Consumers are better off in most cases with non-strategic storage utilization compared to the respective strategic cases. This is particularly true for IC3 vs. IC7: if a strategic generator in an oligopolistic market environment also has a monopoly over storage, strategic storage utilization harms consumers most. The consumer benefits of storage nearly vanish in IC7. Consequently, storage should not be concentrated in the hand of a large oligopolistic generator from a consumer's point of view. In contrast, in a market with perfectly competitive generators (PC cases), strategic storage impacts consumer rents less. Yet in the cases with realistic distribution of storage between different players, strategic storage does not harm consumers. In contrast, consumers benefit most in PC8 and IC8 due to the aforementioned price-smoothing prisoners' dilemma that storage operators face.

5.3.3. Overall welfare

As consumer rent gains are higher than producer losses, storage increases overall welfare in all model runs. Among the cases with perfectly competitive generators, overall welfare does not differ much. Non-strategic storage (PC1-4) generally leads to higher overall welfare than strategic storage utilization (PC5-8). In an oligopolistic market (IC1-8), overall welfare gains of storage are always lower than in PC1-8, whereas differences between the cases are larger. The non-strategic storage cases (IC1-4) still deliver high overall welfare outcomes, but the strategic case IC8 leads to even higher welfare. This is due to high consumer rents in the IC8 case, which result from the storage operators' prisoner's dilemma discussed above. IC8 and IC 4 have the same distribution of storage capacity among players. As the strategic storage case IC8 leads to higher overall welfare

10. It is clear that drawing definite conclusions on the viability of pumped hydro storage investments in Germany is beyond the scope of this article. Note that we only refer to the arbitrage value of storage. Yet pumped storage facilities can generate additional revenue streams by offering other and higher-value ancillary services to the power market in the real world. For example, the provision of reserve capacity or reactive power may lead to higher revenue streams than arbitrage.

than the non-strategic IC4, we conclude that strategic storage operation may have a market power mitigating effect in an otherwise oligopolistic market environment if capacity is distributed among different strategic players.[11] In contrast, monopolistic storage leads to lower overall welfare levels. Strategic merchant storage (IC5) and strategic storage of a generator that has no market power in generation (IC6) leads to welfare results slightly lower than the non-strategic storage cases. Yet welfare gains of storage nearly disappear when the total storage capacity is controlled by the large strategic generator E.ON due to low consumer rents (IC7). We thus conclude that strategic storage operation in an oligopolistic market should be avoided for welfare reasons, if storage is not distributed among several players that also hold other generation capacity.[12]

Finally, we compare the magnitude of welfare losses from strategic storage utilization with those related to strategic conventional generation. Among all model runs, we find the largest potential welfare losses from strategic storage utilization between IC3 and IC7. Strategic storage leads to welfare losses of nearly €2 million for the modeled 13 days, or around €47 million extrapolated to one year. In the more realistic IC8 case, there are hardly any welfare losses of strategic storage compared to IC4 due to the prisoners' dilemma described above. In contrast, the welfare difference between a perfectly competitive and an oligopolistic generation market (PCBase vs. ICBase) is substantially higher at around €47 million for 13 days, or €1.3 billion for a whole year. Accordingly, we conclude that the strategic use of pumped hydro storage is not a relevant source of market power in Germany.

5.4. Sensitivity Analyses for Different Demand Elasticities

The model runs discussed above have been calculated for a price elasticity of demand of 0.45, as this value leads to the most realistic results regarding generation levels and prices. We test the robustness of this assumption for alternative values of $\sigma = 0.3$ and $\sigma = 0.6$.[13] Figure 5 in the Appendix shows the results regarding storage capacity utilization. Note that the same overall storage capacity is available in all cases. We find that more elastic demand ($\sigma = 0.6$) generally increases storage utilization, as price differences between single hours increase and arbitrage becomes more profitable. In contrast, less elastic demand ($\sigma = 0.3$) generally leads to lower storage utilization. Yet the main findings, as discussed

11. The decreasing effect of storage on spot prices can be compared to the effect of forward markets. These may also mitigate market power and improve efficiency under certain conditions. Adilov (2010) makes a recent contribution to this strand of the literature.

12. Note that our results partly support the findings by Sioshansi (2010). He argues that growing numbers of storage operators, i.e. increasingly non-strategic storage utilization, increase welfare, whereas merchant storage operation is closest to the welfare maximum. Yet we show that the issue is more complex in a market with imperfectly competitive generators, in particular if storage is distributed between them.

13. A solver problem occurred for IC3 with $\sigma = 0.3$. We thus omit this case.

in section 5.2, hardly change. Strategic storage operators generally under-utilize their capacity. Monopolistic storage operation in a market with strategic generation (IC5-7) leads to the lowest utilization levels. We thus conclude that our storage utilization results are robust against varying assumptions on demand elasticity.

Figures 6 and 7 show sensitivity results regarding welfare. For $\sigma = 0.6$, results are very robust: Non-strategic storage generally leads to higher welfare than strategic storage. IC8 once again provides an exception because of the prisoner's dilemma discussed above. For $\sigma = 0.3$, results slightly change. The overall welfare gain of storage is now lower in the perfect competition cases (PC1-8) than in the imperfect ones (IC1-8). This is because the market power potential of conventional generators increases with lower demand elasticity. Accordingly, the price-smoothing effect of storage is more valuable in an imperfect competition environment. Yet the most notable difference is that monopolistic storage operation by a strategic generator in an imperfect market (IC7) now leads to welfare and consumer rent losses compared to the baseline without storage. This finding, however, only reinforces our previous conclusion that monopolistic storage ownership should be avoided for welfare reasons.

6. SUMMARY AND CONCLUSIONS

We develop a game-theoretic electricity market model that allows the analysis of strategic electricity storage. We apply the model to the German market and the case of pumped hydro storage. Drawing on different counterfactual and realistic cases, we study the complex interaction between players' decisions on conventional generation and storage under various market power assumptions, and the resulting effects on storage utilization and welfare. Most results are robust for varying assumptions on price elasticity of demand. Although we focus our analysis on the example of pumped hydro storage, the results are applicable to other large-scale storage technologies as well, for example compressed air storage or grid-connected batteries.

We find that storage generally smoothes conventional generation patterns and electricity prices. Our main finding, however, is that not only does the existence of a storage capacity in a market matter, but also storage ownership. Strategic players generally under-utilize their storage capacity. In particular, an oligopolistic generator that exclusively controls the total storage capacity of the market, massively under-utilizes its capacity. In contrast, strategic storage hardly results in under-utilization if the total storage capacity is distributed between several strategic players.

Whereas storage leads to arbitrage profits for the respective players, its price-smoothing effect decreases generation-related producer surplus for all generating firms. Storage operators that also engage in conventional generation may suffer a net loss of their surplus compared to the baseline without storage. There are different reasons for this results, among them a lack of coordination between the maximization of arbitrage profits and generation-related profits as well as adjustments of other strategic generators to the new situation. Moreover, storage operators face a prisoners' dilemma if the total capacity is distributed among several generators. As a consequence of these effects, overall producer rent declines compared to the baseline. In contrast, storage causes an even larger increase in consumer surplus, such that overall welfare increases in all storage cases when compared to the baseline. Nonetheless, welfare results differ substantially between the cases. The positive effect of storage on overall welfare is generally higher in the cases of non-strategic storage operation when compared to the strategic ones. Welfare losses of strategic storage are particularly high if a large oligopolistic generator exclusively controls storage operations. Yet in an oligopolistic market environment, strategic storage operation may lead to high overall welfare, if the total storage capacity is distributed among different players.

Our results suggest that strategic storage is unlikely to be a relevant source of market power in Germany. As storage is distributed across several strategic generators, which face a prisoner's dilemma, strategic storage neither jeopardizes consumer rent nor overall welfare. Moreover, we find that potential welfare losses of strategic storage, even in a counterfactual worst case scenario, are much lower than the welfare losses from strategic conventional generation. Accordingly, economic regulation of existing German pumped hydro capacity is not required. However, the situation may change if additional future storage capacity is controlled by single strategic generators. For example, the involvement of oligopolistic generating firms into loading and discharging of future electric vehicle fleets should be scrutinized.

Aside from welfare considerations, high utilization of storage capacity may be a policy objective. For example, the large-scale system integration of fluctuating renewable generators may require storage capacity to be utilized to the greatest possible extent. Although this issue is not explicitly modeled here, strategic under-utilization of storage capacity may provide an obstacle to renewable integration. In this case, regulators should ensure that storage is operated in a non-strategic way or that capacity is suitably distributed between players.

Finally, our results suggest that investing in new storage capacity is not attractive for players that also hold other generation capacity. Thus, it should not be expected that the incumbent German generators will invest in additional storage capacity, although the resulting effect on overall welfare may be positive. If policy makers aim to increase German storage capacity, they should think about ways of incentivizing investments. Our results suggest that economic incentives could be justified by storage-related welfare gains.

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7. APPENDIX

7.1. Sets, indices, parameters, and variables

Table 5: Sets, Indices, Parameters, and Variables

Item	Description	Unit
Sets and Indices		
F	Firms with $f \in F$	
I	Generation technologies with $i \in I$	Hours
T	Time with $t \in T$	
Parameters		
σ	Price elasticity of electricity demand	
$d0_t$	Hourly reference demand	MWh
$p0_t$	Hourly reference prices	€/MWh
$\bar{x}_{f,i}$	Installed conventional generation capacity	MW
$\overline{st}_f^{out}$	Installed pumped storage discharging capacity	MW
$\overline{st}_f^{in}$	Installed pumped storage loading capacity	MW
$\overline{st}_f^{cap}$	Installed pumped storage capacity	MWh
ξ_i^{up}	Ramping up parameter for conventional generation	
ξ_i^{down}	Ramping down parameter for conventional generation	
vgc_i	Variable generation costs	€/MWh
$vstc$	Variable pumped storage costs	€/MWh
η_{st}	Storage efficiency	
θ_f^{gen}	Market power parameter for generation	0 or 1
θ_f^{st}	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
$\lambda_{f,i,t}^{gen}$	Shadow price of conventional generation capacity constraint	€/MWh
$\lambda_{f,i,t}^{rup}$	Shadow price of ramping up constraint	€/MWh
$\lambda_{f,i,t}^{rdo}$	Shadow price of ramping down constraint	€/MWh
$\lambda_{f,t}^{stout}$	Shadow price of storage discharging capacity constraint	€/MWh
$\lambda_{f,t}^{stin}$	Shadow price of storage loading capacity constraint	€/MWh
$\lambda_{f,t}^{stup}$	Shadow price of upper storage capacity constraint	€/MWh
$\lambda_{f,t}^{stlo}$	Shadow price of lower storage capacity constraint	€/MWh
$\vartheta_{f,i,t}^{gen}$	Conventional generation market share of firm f	
$\vartheta_{f,t}^{out}$	Storage discharging market share of firm f	
$\vartheta_{f,t}^{in}$	Storage loading market share of firm f	
$crent_t$	Consumer rent of period t	€
$prent_{f,t}$	Producer rent of firm f in period t	€

7.2. KKT conditions

$$0 \le vgc_i + \lambda^{gen}_{f,i,t} + \lambda^{rup}_{f,i,t} - \lambda^{rup}_{f,i,t+1} - \lambda^{rdo}_{f,i,t} + \lambda^{rdo}_{f,i,t+1} - p_t\left(1 - \frac{\sum_{i \in I} \vartheta^{gen}_{f,i,t}\theta^{gen}_f + \vartheta^{out}_{f,t}\theta^{st}_f - \vartheta^{in}_{f,t}\theta^{st}_f}{\sigma}\right) \perp x_{f,i,t} \ge 0,\ \forall f,i,t \tag{5a}$$

$$0 \le vstc + \lambda^{stout}_{f,t} + \sum_{\tau=t}^{T}\lambda^{stlo}_{f,\tau} - \sum_{\tau=t}^{T-1}\lambda^{stup}_{f,\tau+1} - p_t\left(1 - \frac{\sum_{i \in I} \vartheta^{gen}_{f,i,t}\theta^{gen}_f + \vartheta^{out}_{f,t}\theta^{st}_f - \vartheta^{in}_{f,t}\theta^{st}_f}{\sigma}\right) \perp stout_{f,t} \ge 0,\ \forall f,t \tag{5b}$$

$$0 \le \lambda^{stin}_{f,t} - \sum_{\tau=t}^{T-1}\lambda^{stlo}_{f,\tau+1}\eta_{st} + \sum_{\tau=t}^{T}\lambda^{stup}_{f,\tau}\eta_{st} + p_t\left(1 - \frac{\sum_{i \in I} \vartheta^{gen}_{f,i,t}\theta^{gen}_f + \vartheta^{out}_{f,t}\theta^{st}_f - \vartheta^{in}_{f,t}\theta^{st}_f}{\sigma}\right) \perp stin_{f,t} \ge 0,\ \forall f,t \tag{5c}$$

$$0 \le -x_{f,i,t} + \bar{x}_{f,i} \perp \lambda^{gen}_{f,i,t} \ge 0,\ \forall f,i,t \tag{5d}$$

$$0 \le -x_{f,i,t} + x_{f,i,t-1} + \xi^{up}_i \bar{x}_{f,i} \perp \lambda^{rup}_{f,i,t} \ge 0,\ \forall f,i,t \tag{5e}$$

$$0 \le -x_{f,i,t-1} + x_{f,i,t} + \xi^{down}_i \bar{x}_{f,i} \perp \lambda^{rdo}_{f,i,t} \ge 0,\ \forall f,i,t \tag{5f}$$

$$0 \le -stout_{f,t} + \overline{st}^{out}_f \perp \lambda^{stout}_{f,t} \ge 0,\ \forall f,t \tag{5g}$$

$$0 \le -stin_{f,t} + \overline{st}^{in}_f \perp \lambda^{stin}_{f,t} \ge 0\ ,\forall f,t \tag{5h}$$

$$0 \le -\sum_{\tau=1}^{t} stout_{f,\tau} + \sum_{\tau=1}^{t-1} stin_{f,\tau}\eta_{st} \perp \lambda^{stlo}_{f,t} \ge 0,\ \forall f,t \tag{5i}$$

$$0 \le -\sum_{\tau=1}^{t} stin_{f,\tau}\eta_{st} + \sum_{\tau=1}^{t-1} stout_{f,\tau} + \overline{st}^{cap}_f \perp \lambda^{stup}_{f,t} \ge 0,\ \forall f,t \tag{5j}$$

$$0 = \mathrm{X}_t - d0_t\left(\frac{p_t}{p0_t}\right)^{-\sigma},\ p_t\ free,\ \forall t \tag{5k}$$

Equations (5a)–(5k) include market shares $\vartheta^{gen}_{f,i,t}$, $\vartheta^{out}_{f,t}$, and $\vartheta^{in}_{f,t}$ as defined in (6a)–(6c). They indicate a player's ability to raise prices beyond marginal costs.

(5a)–(5k) also include market power parameters θ_f^{gen} and θ_f^{st}. By exogenously assigning the values 0 or 1, we can "switch" off and on market power for specific firms both regarding generation and storage operation.

$$\vartheta_{f,i,t}^{gen} = \frac{x_{f,i,t}}{X_t}, \ \forall f,i,t \tag{6a}$$

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

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

Conditions (5a)–(5c) may be interpreted as follows. Equation (5a) includes a standard Cournot result: In case of positive market shares $\sum_{i \in I} \vartheta_{f,i,t}^{gen}$ 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. Whereas this is a common feature 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 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. The reason is that storage operators face 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. Strategic storage operation thus mitigates a strategic generator's incentives to raise prices by withholding conventional capacity during the periods of storage loading. Note that the market shares also enter equations (5b) and (5c), which may be interpreted accordingly.

7.3. Market Power Parameters in Different Scenarios

Table 6: Market Power Parameters in Different Scenarios. Note that the parameters hold for all technologies *i* and hours *t*.

Case	Conventional generation	Storage
PCBase	$\theta_f^{gen}=0\forall f$	—
PC1, PC2, PC3, PC4		$\theta_f^{st}=0\forall f$
PC5, PC6, PC7, PC8		$\theta_f^{st}=1\forall f$
ICBase	$\theta_f^{gen}=1$ for $f=$EnBW, E.ON, RWE, Vattenfall $\theta_f^{gen}=0$ for $f=$Fringe	—
IC1, IC2, IC3, IC4		$\theta_f^{st}=0\forall f$
IC5, IC6, IC7, IC8		$\theta_f^{st}=1\forall f$
EONBase	$\theta_f^{gen}=1$ for $f=$E.ON $\theta_f^{gen}=0$ for $f=$EnBW, RWE, Vattenfall, Fringe	—
EON7		$\theta_f^{st}=1\forall f$

7.4. Additional Model Run

In this model run, we assume that the largest generating firm, E.ON, is the only player to have market power regarding conventional generation. That is, $\theta_f^{gen}=1$ for $f=$E.ON, whereas $\theta_f^{gen}=0$ for $f=$EnBW, RWE, Vattenfall, Fringe. Furthermore, we assign the whole storage capacity to E.ON and assume that it is operated in a strategic way.

Table 7: Producer Rent Differences to EONBase in Million €. The bold number indicates the storage operator.

	EON7
EnBW	–0.45
E.ON	**+0.04**
RWE	–1.07
Vattenfall	–0.70
Fringe	–0.97
NoGen	0.00
Total	–3.15

7.5. Sensitivity Analyses for Different Demand Elasticities

Figure 5: Total Storage Output over 13 Days for Different Values of σ

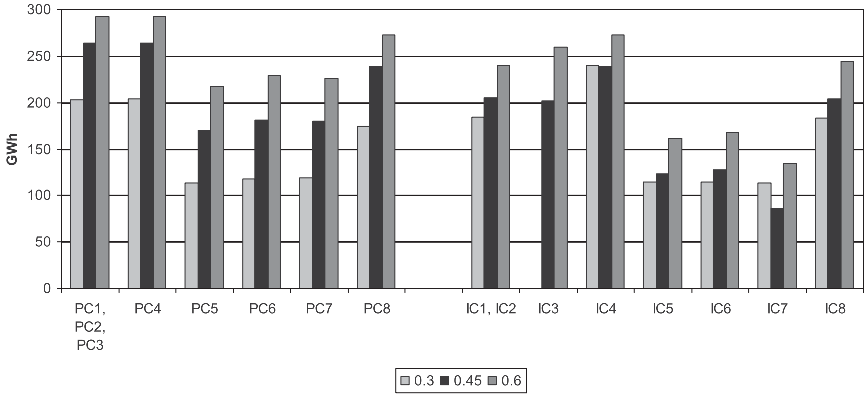


Figure 6: Welfare Results for $\sigma = 0.6$: Differences to Respective Baselines over 13 Days

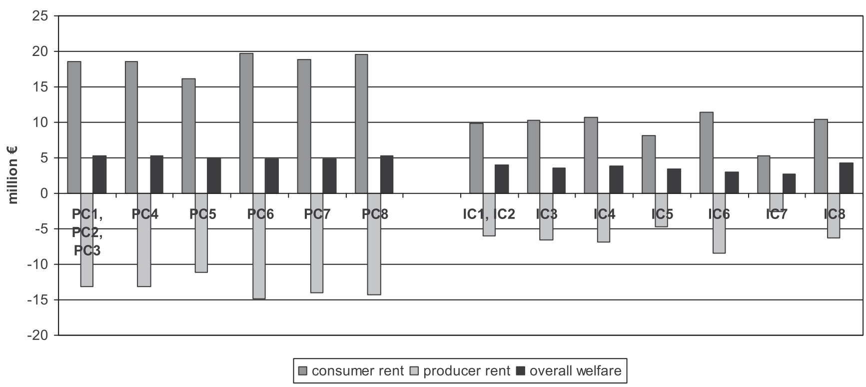
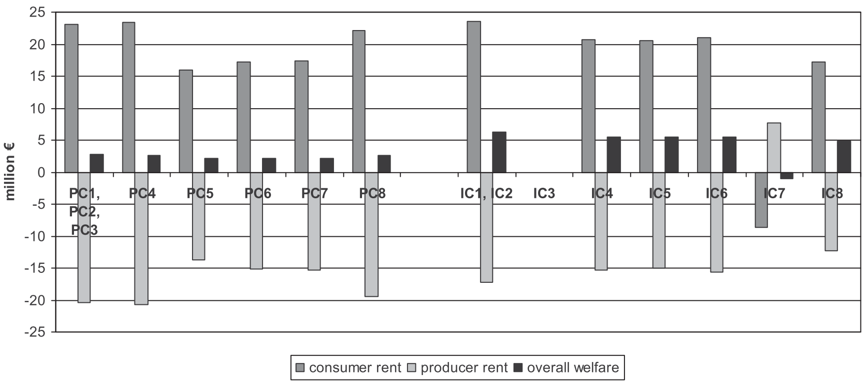


Figure 7: Welfare Results for $\sigma = 0.3$: Differences to Respective Baselines over 13 Days



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