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Catching the maximum market value of the electricity storage – technical, economic and regulatory aspects

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Abstract : The creation of competitive wholesale electricity markets allows to evaluate the "arbitrage value" of an electricity storage unit, which stems from buying and storing electricity when prices are low, and selling it when prices are high. The focus of this paper is to demonstrate that the arbitrage value can be highly sensitive with respect to the dimensioning of an electricity storage unit. A simulation model is explored to calculate the arbitrage value of different storage units by finding the optimal hourly operating strategy during one-year period. The results of simulation show that optimizing the dimensioning of a storage unit is as important as choosing the fittest technology. Furthermore we provide evidence that the optimal set-up of a storage unit can adapt to exogenous factors such as grid tariff and local electricity price characteristics. These findings suggest that the maximisation of market value of electricity storage should be based on the optimisation of the dimensioning of the storage unit in specific economic and regulatory environment.

Key words: electricity storage; arbitrage value; regulation

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1. Introduction

Due to the non-storability of electric energy, the production of electricity is adjusted simultaneously to the varying demand. Indirect storage technologies allow to decouple primary electricity generation from demand. By transforming electricity into a storable form of energy (mechanic energy, chemical energy, heat, etc.), storing this energy and, at a later point in time, retransforming it into electricity, power supply can be intertemporaly shifted. The two most important families of electricity storage technologies are on the one hand mechanical power conversion systems, such as Pumped Hydro Storage (PHS), Compressed Air Energy Storage (CAES) as well as flying wheel electricity storage. On the other hand there are electro-chemical power conversion systems, including Lead-acid, Sodium sulfur (NaS), *Lithium-ion (*Li-ion), Zinc bromide (Zn/Br), Nickel-cadmium (Ni/Cd) as well as Vanadium Redox batteries. The most commercial viable and widespread bulk energy storage technology to date is the PHS, with a global installed capacity of over 100 GW.

The use of energy storage technologies in electric systems has a long history. At the beginning of the 20th century, lead-acid batteries were charged during the day in order to supply the demand during the night in small local DC power systems. Later on the major tasks of electricity storage systems became to smooth the load curve, reduce the peak-load asset utilization, and thereby decrease the cost of supplying energy to end-users[2]. Most of the storage technologies were implemented in centrally planned electricity systems by vertically integrated utilities. Since the 1990s, the power sectors in many countries have been deregulated, splitting up vertically integrated monopolies, creating wholesale markets and introducing high-frequency price signals. These reforms have profound influence on the conduct of business in the electric sector. Investment decisions in generating and storage facilities, for example, are based more and more on market signals instead of guaranteed/regulatory tariff. In addition, the technical maturation of certain bulk energy storage technologies (CAES, batteries) raised the issue of their cost efficiency. Thus, a literature on the evaluation of storage technologies in the market context emerged.

The creation of spot market of electricity gives energy storage facilities the opportunity to exploit the hourly price differential in the market by buying and storing electricity when prices are low, and selling it when prices are high. The profit earned as such is called the “arbitrage value” of storage facility. Walawalkar and Apt (2008) offer a round estimation of the arbitrage value of an electricity storage unit with certain energy delivery duration by determining and fixing *a priori* a constant arbitrage period on daily basis in the PJM and New York electricity market. Sioshansi *et al* (2008) improve the estimation of the arbitrage value of storage by using a two-week optimization horizon on the PJM Spot market. Lund *et al* (2008) seek to find out the highest arbitrage value for a given CAES plant by optimizing its hourly operation strategy on a given spot market (Nordpool) at one-year horizon. Dufo-Lopez *et al* (2008) try to identify the average spot price spread that allows a Wind-Batteries system to be as profitable as a Wind-Only system. Much (2009) performs a price-based unit commitment planning for a given pump storage plant to assess the real option value of the storage unit.

While these studies are useful to give knowledge about the arbitrage value of or required by the energy storage facilities, they nevertheless feature two main drawbacks : first, most studies do not compare the potential arbitrage value of a storage facility to the corresponding fixed cost of the storage unit. As a consequence, we cannot figure out the storage unit that entails the best return on invested capital. And second, all papers assume that the storage units have equal charge and discharge capacity (or equal charge

[2] See Schoenung et al (1996).

and discharge duration). However, as we will present in detail in the next section, the three vectors of an electricity storage unit - storage capacity (MWh), charge rate (MW) and discharge rate (MW), can be configured separately in many cases.

Let's consider a simple example. For a given energy capacity, a storage unit can be shaped to high charge rate (short charge duration) and low discharge rate (long discharge duration) or inverse. These two configurations will entail almost the same investment cost but the second should have a higher arbitrage value than the first, as low prices in power markets generally last longer than peak prices[3]. Intuitively, the arbitrage value of a storage facility should thus be sensitive to its dimensioning.

One of the objectives of the present paper is to analyze the sensitivity of arbitrage value of a storage unit to its dimensioning. More generally, our work is aimed at developing a framework and a method to analyze the sensitivity of profitability of storage to different endogenous and exogenous factors[4] and to detect the eventual interactions between them. A sensitivity analysis of profitability of storage with respect to these factors can help us finding the most cost-effective storage unit as well as anticipating the perspective of energy storage in different scenarios in the future. We will concentrate in this paper on the impact of 1) Power rating dimensioning, 2) spot price dynamics, and 3) network tariff on the profitability of two electricity storage technologies: PHS and CAES.

Still, we are aware of the fact that remunerations of a storage facility in the electricity sector are in most cases only partly market based. While most countries establish competitive spot markets, the compensation for the system services (reserve, frequency control, etc.) that storage facilities may (or have to) deliver often occurs at complicated regulated tariffs and at different conditions. These tariffs might or might not allow for a complementary use of the storage unit in the regulated and the non-regulated segment[5]. And they might be in favour of or penalize certain technologies or certain dimensioning of storage facility[6]. Hence the economic value of a storage facility should consist of the optimal combination of value stemming from the regulated tariffs and value stemming from competitive market operations.[7]

In this paper we restrain from entering into the details of regulated tariffs and the corresponding optimal allocation of storage capacity by assuming that market prices are efficient enough not to provide extraordinary arbitrage potentials between regulated and non-regulated prices. Thus, we suppose in this paper, that the dimensioning of a storage facility that is optimal with respect to market prices is not fundamentally different from a

[3] The negative prices that have been recently observed in some exchanges (Germany, Denmark, PJM, ERCOT, etc) may change our cognition about the typical price pattern with low prices lasting longer than high prices. However, as long as the occurrence of negative price is not as frequent as daily-cycled or weekly-cycled, we can consider that the price pattern does not change fundamentally.

4 Endogenous factors are defined as factors related to the storage unit itself, such as charge/discharge capacity, storage capacity, charge/discharge efficiency, parasitic loss, life cycle, etc. Exogenous factors refer to the economic and regulatory environment such as spot price patterns, fuels costs, CO2 cost, capacity payment arrangement, etc.

[5] Schoenung and Eyer (2008) have been aware of the versatility of energy storage facilities and endeavored to propose several plausible combinations of different application that an electricity storage unit can create in order to estimate the aggregated value of storage.

[6] For instance, NYISO allows energy storage units to receive capacity credit if they can provide energy for 4 successive hours (NYISO 2005)

[7] Nowadays, most of the electricity storage facilities are owned by producers in liberalized electricity markets. Besides providing required ancillary services, the electricity storage facilities are used to store low cost/low price energy for sale at higher market prices. Thus the electricity storage facilities participate either directly or indirectly in the spot market arbitrage.

unit that is dimensioned with respect to regulated tariffs in the same market.[8] The paper is structured as follows. In Section 2, we describe and explain the major technical and economical characterization of the analysis. Section 3 introduces the methodology that we explore to calculate the profitability of electricity storage units. In the section 4 results are presented and analyzed. The paper concludes with section 5.

2. Technical and economic characterization

In this section, the technical characterization of electricity storage technologies studied is explained. Then, the economic assumptions about the cost of electricity storage units investigated as well as the assumptions on the economic and regulatory environments are presented.

2.1 Technical characterization of electricity storage units

2.1.1 Possibility of dimensioning the electricity storage units

This paper attempts to investigate how the dimensioning of a storage unit may influence on its economic value. Therefore, the relevant technologies for such study should endow a flexibility of dimensioning. Such flexibility exists in CAES and PHS units, but is very limited for batteries.

Generally, an electricity storage unit consists of an energy storage reservoir and a power conversion system (PCS). The former determines the energy rating of the storage unit in MWh, the latter establishes the interface between the storage unit and the electric grid and is rated at the power level (MW) required for withdrawing power from the grid (charge the storage unit) or for injecting electricity to the grid (discharge the storage unit). For the technology of CAES, in the charging stage, we use electricity to drives a compressor that squeezes the ambient air into a cavern. Then the air is stored in the form of compressed air. In the discharging stage, the compressed air is released, heated with a small amount of fuel, and is fed into a turbine to generate electricity. A manufacturer can decide on the power of the corresponding compressor and turbine individually (i.e., they do not need to be of equal size)[9].

The principal of pumped storage technology is well known. Off-peak electricity is used to pump water from a lower elevation to a higher elevation where it is stored in a reservoir; during peak hours this water is released through a turbine to produce electricity. However, in the family of PHS units, we can further distinguish three possible technical configurations of PCS[10]: 1) Group of four units, in which a pump coupled to a motor and a turbine coupled to a generator; 2) Group of three units, in which a pump and turbine both coupled to a single reversible motor/generator and 3) Group of two units, in which a reversible pump-turbine (i.e. Francis turbine) coupled to a reversible motor/generator. In 1) and 2), we can optimise the pump and turbine ratings in order to achieve best performance, while in 3), the pump and turbine capacity is basically symmetric. Nowadays, most of the PHS plants are two units group, featuring the use of reversible Francis turbines. However, this does not make optimising the dimensioning of storage unit an irrelevant issue for future PHS facilities, mainly for two reasons. First, by coupling the reversible pump-turbines with pure turbines, we can still achieve different charge and

[8] Please note, that a negation of this strong assumption does not influence the main message of this paper (that the value of a storage unit can only be evaluated after its set-up has been optimized with respect to the market environments).

[9] As a matter of fact, the first CAES plant in the world, Huntorf plant in Germany, has a compressor of 60 MW and a turbine of 290 MW.

10 See Brown P. D (2006)

discharge capacity for PHS plant. The French Grand Maison PHS plant represents such a hybrid form of configuration, which has a turbine capacity of 1790 MW and pump capacity of 1160 MW, made up by 8 reversible Francis turbines and 4 Pelton turbines. Second, it is widely recognised that the potential of developing new hydro power plant or pumped storage plant is very limited because most of the suitable sites have been already explored. The tendency emerged in several countries such as Switzerland is to transform the old hydro power plant into pumped storage plant. In some cases, only pumps or some ancillary machinery need to be installed. Optimising the dimensioning of the PHS unit is what should be considered at the very beginning of such transformation project.

Compared to the CAES and PHS technologies, battery systems are characterised by a rather rigid input/output power ratio or power/energy ratio. The former is due to the fact that the PCS of battery systems is one single cellule which imports the electric energy from the grid into the battery and inversely, exports the electric energy from the battery to the grid. Thus, the charge and discharge capacity is d*e facto* symmetric as long as the two processes are carried out by one device. We may have the possibility to have very different charge and discharge capacity by installing a parallel PCS system. But this will lead to an important surcost which is not economical. The battery systems also have a rigid power/energy ratio. To date, notwithstanding the fact that the high-temperature NaS battery has achieved numerous successes in Japanese and American markets, there are only two available modules of NaS batteries for peak shaving purpose (50 kW/430 kWh, and 50 kW/360 kWh). The flow batteries may overcome this rigidity as the electrolyte, which decides the energy rating of the battery is stored in external tanks and can be increased independently from the power rating of the battery. However, the flow batteries are still in early phase of deployment and present low cost certainty.

Therefore, in our analysis we will focus on two electricity storage technologies which are CAES and PHS.

2.1.2 Cost elements of electricity storage unit

Conventionally, the power rating of an energy storage unit refers to its discharge power supposing either equal charge and discharge capacity or equal charge and discharge duration. In order to be able to deduce the cost of the charge unit and the cost of the discharge unit separately, we assume that the investment cost for the charge unit and the discharge unit are equal.[11] We refer to the report for the Department of Energy of the United States (DOE) realized by Schoenung and Hassenzahl (2003) in which they describe the elements of the investment cost for various electricity storage technologies. The power related cost displayed in this report refers to the cost for the whole PCS system per MW of discharge capacity, assuming an equal charge and discharge capacity for PHS and a charge/discharge power ratio of 0.73 for CAES. As explained above, we can therefore divide the total power related cost by 2 (by 1.73) to get the separate cost for charge capacity and discharge capacity for PHS (CAES), as presented in Table 1.

The energy related cost refers to the cost of the energy storage unit (reservoir) and Balance-of-Plant (BOP) cost. The Balance-of-plant consists in all the ancillary equipments that are needed to support the main equipments such as compressors and turbines in a plant. The balance-of-plant costs the energy storage facilities are typically proportional to their energy capacity. The fixed operation and maintenance (O&M) cost is calculated as the annual labor cost to operate and maintain the plant and is assumed to be proportional to the average of charge and discharge capacity.

[11] This assumption is a simplified representation of reality and should be subject to modification when more information is available.

Table 1. Fixed life-cycle cost for CAES, PHS and NaS

PNX 2007 CAES	optimal ROIC	optimal annual net profit	Charge hours	Discharge hours
Grid tariff=0€/MWh	**79%**	**8348186**	6	4
Grid tariff=10€/MWh	66%	6958162	6	4
Grid tariff=20€/MWh	**56%**	**5959296**	8	3

Source of data: Schoenung and Hassenzahl (2003)

* Separate charge /discharge capacity.

** Dollars are converted to Euros with a conversion rate 1:1

2.1.3 Efficiency of electricity storage technologies

The power conversion efficiencies of the two electricity storage technologies are presented in Table 2. PHS is a mature energy storage technology that we assume, based on the median of reported values, to have a round trip efficiency of 75%.[12] A CAES consumes around 0.65MWh of electricity and 1.17MWh of natural gas to produce 1MWh of electricity.[13] Thus the round trip efficiency of CAES is 154%[14]. The charge/discharge efficiencies are assumed to be symmetric and thus equal to the square root of their round trip efficiency.

Table 2. Efficiencies for CAES and PHS

	Round trip efficiency	Charge efficiency	Discharge efficiency
CAES	154%	124%	124%
PHS	75%	87%	87%

We select the two storage technologies to perform a sensitivity analysis on their arbitrage value with respect to different exogenous and endogenous factors. However, as stated above, the optimal composition of market value and non-market value can be different for different technologies. Hence, the comparison of the arbitrage value for different technologies cannot allow us to infer the relative advantage of one technology over the other. So we would like to emphasize that a direct comparison of the cost-effectiveness of these two technologies is not intended. Hereafter, we will introduce the main assumptions our analysis is based on.

2.2. Integration in electricity systems and markets

2.2.1 Additional fuel and CO2 emission cost for CAES.

Different from PHS, CAES needs to consume gas to produce electricity, thus the associated gas cost and CO_2 emission cost must be taken into account for operational decisions. CAES consumes about 1.17 MWh of natural gas and emits 250 kg of CO_2 per MWh of electricity produced. Assuming the gas price to be 20 €/MWh [15] and the CO_2 price to be 25 €/ton[16], the total fuel and CO_2 emission cost for CAES is about 30 € per MWh of

12 See Yiannis A. K, Emmanuel S. K. (2007) and Allen G et al (2006)

13 See Fritz Crotogino (2006)

14 Round trip efficiency is defined as the ratio between electricity injected and electricity re-produced. Because of external fuel consumption, the electrical round trip efficiency of CAES is above 100%.

15 NBP price for gas was fluctuating around 20 €/MWh during 2007. (Source: CRE 2007. Electricity and gas market observatory)

16 The CO_2 price in 2007 was almost zero. However, for other years, we can reasonably assume that the CO_2 price is around 25 €/ton (Alberola et al (2007)).

electricity produced. In the computation, we take 30€/MWh as the variable cost of CAES, which has a direct impact on the operation decision.

2.2.2 Discounting rate

In the electricity sector, the annual discounting rate for investment is generally situated between 10% and 15%. A higher discounting rate corresponds to a higher required return on investment. In our analysis, we assume that the discounting rate for investment in electricity in storage is 10%.

2.2.3 Grid tariff for the connection of electricity storage units

To be able to do arbitration in electricity spot markets, bulk electricity storage units have to be connected to the grid. The grid tariff stipulation for energy storage units varies from country to country. For instance, the energy storage units in France are currently treated as load. The grid access tariff is given by [17]:

$$\text{Grid tariff} = a \times C_{\text{subscribed}} + b \times \tau^{c} \times C_{\text{subscribe d}} + X$$
$$\tau^{c} = \frac{E_{\text{withdrawn}}}{8760 \times C_{\text{subscribed}}}$$

Where a, b, c are cost coefficients which vary according to different voltage levels, X stands for the additional fees related to the power that goes above the subscribed capacity.

This formula indicates that the grid tariff is charged according to the power subscribed and to the amount of energy withdrawn from the grid. By contrast, the grid tariff design in Switzerland is more favorable for energy storage units. There, storage units are recognized as a feed-in source rather than load. A “correction factor” (K factor) allows to exempt connection points from the basic tariff, either fully or in part if they (re-) inject a certain fraction of their electricity withdrawn from the grid[18]. The K factor is calculated as :

$$K = \begin{cases} 1 & x \leq 1/4 \\ [5/(1+x)-1]/3 & 1/4 < x < 4 \\ 0 & x \geq 4 \end{cases}$$ x = feed-in energy/ feed-out energy

Therefore, when the feed-in energy is 4 times larger than the feed-out energy, the grid tariff is zero. It is also worth noting that the feed-out energy in the formula is measured as energy withdrawn from the grid minus energy used for the pumps and the stations' own needs. In other terms, the losses incurred during the energy storage and transformation process are not counted as consumption. Thus the Swiss energy storage facilities are much less burdened by the grid tariff than similar installations in other countries, e.g. France. The most energy storage friendly grid tariff is found in Germany, where the recently implemented German Grid Expansion Act exempts grid access fees for new back-up electric storage facilities for 10 years [19].

Our calculation shows that the grid tariff for energy storage generally situates between 0~20€ per MWh of energy withdrawn from grid for different utilization patterns and different tariff structure. We pick up three representative scenarios (as shown in Table 3 in order to test the sensitivity of the economic value of energy storage to the grid tariff).

[17] Source: RTE (2006).
[18] Source: Swiss grid (2009).
[19] Source: Platts—European Power Daily, volume 11, 26/08/2009

Table 3. Grid tariff for Energy storage units

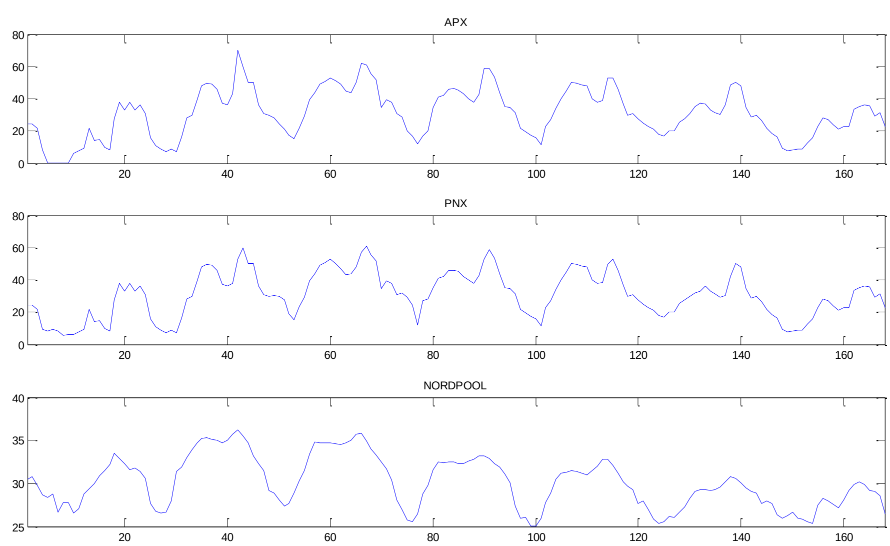
	Low scenario	Medium scenario	High scenario
Grid tariff	0 €/MWh	10 €/MWh	20 €/MWh

2.2.4 Spot market prices

We use hourly day-ahead spot market prices of the year 2007 in three organized electricity markets: Powernext in France, APX in the Netherlands, and NordPool in the Nordic countries. As presented in Figure 1, the NordPool spot market presents low price level and also low volatility because of the hydro dominance in the Nordic countries. By contrast, the APX is highly volatile (with the highest prices, on average 67.5 €/MWh, at 12 a.m.). The Powernext spot market generally represents a case in between, though the year 2007 was characterized by a number of extreme spikes up to 2500 €/MWh in October.[20] The exchange volume in the Powernext day-ahead market in 2007 was about 44 TWh, which is 8% of annual French electricity consumption[21]. In APX, the exchange volume is about 22 TWh, representing 18% of annual consumption[22]. The NordPool is the most liquid power exchange in Europe. The exchange volume in the NordPool spot market during 2007 was about 290 TWh, representing about 70% of annual consumption[23].

We assume that these three spot markets are competitive and liquid so that the market participants act as price takers. Therefore, we can consider that the operations of electricity storage units respond to the market price but don't have any influence on the price levels.

Figure 1. Prices in the first week of 2007 for the three considered markets



3. Methodology

The aim of this section is to introduce a methodology that is suited to demonstrate that the profitability of a storage facility from market arbitrage crucially depends on its dimensioning, and on exterior economic and regulatory environment such as the

[20] CRE (2008).
[21] Source: Powernext 2007 Market Activity
[22] Source: APX Group Annual Report 2007
[23] Source: Nord Pool Annual Report 2007

electricity price dynamics and grid tariff. To test these hypotheses we proceed in three steps: First, we define a finite number of storage facilities. Second, we calculate the ex-post optimal hourly strategy for each unit in different markets. In a third step, we compare the annual net profit of the storage unit with its levelized investment cost to obtain the Return on Invested Capital (ROIC).

3.1 Storage units' set-up

For each of the two studied storage types – pumped hydro storage and compressed air storage– we consider different combinations of charge rate, discharge rate and storage capacity for a given amount of initial investment cost which is 100 m € (Fixed O&M cost is not included) in order to facilitate the calculation of profitability indicator later on. We consider 64 different storage configurations, which are characterized by an identical initial investment of 100m €, and all combinations of eight steps of maximum charge duration (1, 2, 3, 4, 6, 8, 10, 12 hours until full charging from zero) and eight steps of maximum discharge duration (1, 2, 3, 4, 6, 8, 10, 12 hours until full discharging of the completely filled storage)[24]. To obtain the corresponding dimensioning in terms of power/capacity we note that the charge/discharge duration is the ratio of the capacity divided by the charge/discharge rate:

$$\text{maximum charge duration} = \frac{\text{energy capacity}}{\text{maximum charge rate} \times \text{charge efficiency}}$$

$$\text{maximum discharge duration} = \frac{\text{energy capacity} \times \text{discharge efficiency}}{\text{maximum discharge rate}}$$

The maximum charge rate is the active power rating of the storage facility in charging phase. It can be thought of as the maximum rate at which energy is withdrawn from the grid and injected into the storage facility.

The maximum discharge rate is the active power rating of the storage facility in discharging phase. It can be thought of as the maximum rate at which energy is taken out of the storage facility and injected into the grid.

As the total investment costs are:

$$\begin{aligned} \text{investment cost} & \\ &= \text{energy related cost} \times \text{energy capacity} \\ &+ \text{charge unit related cost} \times \text{Max. charge rate} \\ &+ \text{discharge unit related cost} \times \text{Max. discharge rate} \end{aligned}$$

the maximum charge and discharge rate as well as the storage capacity can be calculated (by rearranging the three equations according to the three unknown variables) for each considered unit taking into account the cost components and efficiencies given in Table 2 and Table 1. Given a total investment cost of 100 million €, the discharge capacity in these configurations ranges from some 80 MW to some 200 MW, representing medium-sized electricity storage facilities.

3.2 Ex-post optimal hourly strategy

In the second step, taking the price dynamics in three different markets – namely France,

[24] The selection of these eight steps of charge/discharge duration is based on the observation of intra-daily spot market price pattern: the low prices that usually happen during the off-peak hours can hardly last for 12 consecutive hours, whereas the peak prices often occurs during several hours.

Netherlands and Nordpool - for one representative year (2007) we can calculate the payoff under the optimal strategy given the above defined technical characteristics.

The ex-post optimal storage strategy (i.e., the path of charging/discharging decisions ΔV_t) is calculated by maximizing the annual gross profit $\pi = \sum_{t=t_0}^{\infty} \Delta V_t p_t - c(\Delta V_t, p_t, V_t)$ with respect to the given electricity prices p_t and the cost function $c(\Delta V_t, p_t)$. The cost of charging/discharging actions of storage units depends on the technology. The CAES, for example, requires an external energy source as the compressed air has to be heated in order to expand and to drive the turbine. Thus, fuel and emission costs for discharging are assumed to be 30 €/MWh. Losses (due to the power conversion efficiency) are also treated as cost. This is necessary, as treating losses physically would lead to significant rounding errors, because the volume levels and the decisions have always to correspond to the volume grid (1MWh).[25] Thus, charging a storage unit by 10 MWh when the price is 10 €/MWh does not only cost 100 € but 117.65 € when the charging efficiency is at 85%.[26] Discharging a storage unit by 10 MWh when the price is at 100 € does not earn 1000 € but 850 € when discharging efficiency is 85%. We assume that the storage facility does not encompass a time loss (loss of energy when it is stored in the reservoir), for the reason that the time loss rate is very low for these three technologies and that they are intended to short term arbitrage.

The general idea of the method is to optimize storage usage decisions backwards in time using a discrete (hourly) time grid and a discrete volume grid. The volume grid stretches from minimum to maximum storage level at equal distance (1 MWh) volume steps. At each point in time, only a well defined set of decisions are allowed. The decision must not imply that the storage volume becomes smaller (bigger) than the minimum (maximum) storage capacity and that the injection (or withdrawal) exceeds the charge (or discharge) capacity:[27]

$$V^{min} < V_{t-1} + \Delta V_t < V^{max}$$
$$\Delta V^{min} < \Delta V_t < \Delta V^{max}$$
$$|\Delta V_t| = 1\text{MWh} \times N \qquad N \in \{1,2,3 \ldots\}$$

Each storage level at each point in time implies a certain *continuation value* (i.e., the value that the energy stored at this point of time will bring later before termination date) that depends on the characteristics of the unit and the future price development. Any storage decision leads to a present payoff (negative if charging and positive if discharging) as well as a change in the *continuation value* (positive if charging and negative if discharging). Thus, the storage operator has to select the decision that maximizes the sum of the present payoff and the *continuation value* at each point in time. To do so, a certain termination date (T) and termination volume (V_T) have to be defined. We assume that both, the initial volume V_0 and the desired storage level in the last period V^* equal the half of the maximum storage level V^{max}. We impose that the payoff is zero if the volume exceeds a desired level (V^*) and that a punishment of doubling the price for volumes below the desired level has to be paid.[28] This yields:

[25] Example: at a charge efficiency of 85% and a charge rate of 3 MW/h the loss would be 0 MWh/h (3 MWh - 3 MWh×0.85 = .45 ≈ 0) while at 4 MWh it would be 1 MWh/h (4 MWh - 4 MWh×0.85 = .6 ≈ 1). This would distort the decision, as charging 3MWh would in the above example always be preferable to charge 4MWh.
[26] 11.765MWh×0.85≈10MWh.
[27] Consider a storage unit with 10 MWh storage capacity, a charge rate of 5 MWh and a discharge rate of 2 MW. At 11 p.m. the storage unit is plain (10 MWh stored). Thus, only three decisions are allowed in the subsequent hour: do nothing, discharge one MWh or discharge 2 MWh.
[28] This essentially imposes that the storage operator will in almost all cases end up at the desired storage level at the termination date.

$$\text{Value}_{\text{T}}\left(\text{p}_{\text{T}}, \text{V}_{\text{T}}\right) = \text{Payoff}_{\text{T}}\left(\text{p}_{\text{T}}, \text{V}_{\text{T}}\right) = \begin{cases} 0 & \text{V}_{\text{T}} > \text{V}^* \\ -2(\text{V}^* - \text{V}_{\text{T}})\text{p}_{\text{T}} & \text{V}_{\text{T}} < \text{V}^* \end{cases}$$

Having the payoff at the termination date for each volume level one can find the optimal decision in $\text{T} - 1$ for each volume level. This is done by finding the decision that maximizes the sum of present payoff and *continuation value* (i.e., the payoff at the termination date) for the set of allowed decisions at this volume.[29] The continuation value at a certain the volume level in $\text{T} - 1$ is the sum of the present payoff and the continuation value given the above deduced optimal decision. Thus, the continuation values at $\text{T} - 1$ can be calculated for all volume levels :

$$\begin{aligned} &\text{Value}_{\text{T}-1}\left(\text{p}_{\text{T}-1}, \text{V}_{\text{T}-1}, \Delta\text{V}_{\text{T}-1}\right) \\ &\qquad = \text{p}_{\text{T}-1} \times \Delta\text{V}_{\text{T}-1} + \left(\frac{1}{1+\text{r}}\right)^{\frac{1}{8760}} \\ &\qquad \times \left(\text{Value}_{\text{T}}\left(\text{p}_{\text{T}}, \text{V}_{\text{T}-1} + \Delta\text{V}_{\text{T}-1}\right) - \text{c}(\Delta\text{V}_{\text{T}-1}, \text{p}_{\text{T}-1})\right) \end{aligned}$$

"r" refers to hourly discounting rate in the optimization algorithm. Proceeding as before, the optimal decisions and the continuation values at $\text{T} - 2$ can be calculated. This backward iteration is continued until $\text{t} = 0$ is reached:

$$\begin{aligned} &\text{Value}_{\text{T}-\text{i}}\left(\text{p}_{\text{T}-\text{i}}, \text{V}_{\text{T}-\text{i}}, \Delta\text{V}_{\text{T}-\text{i}}\right) \\ &\qquad = \text{p}_{\text{T}-\text{i}} \times \Delta\text{V}_{\text{T}-\text{i}} + \left(\frac{1}{1+\text{r}}\right)^{\frac{1}{8760}} \times \left(\text{Value}_{\text{T}-\text{i}+1}\left(\text{p}_{\text{T}-\text{i}+1}, \text{V}_{\text{T}-\text{i}+1}\right) - \text{c}(\Delta\text{V}_{\text{T}-\text{i}}, \text{p}_{\text{T}-\text{i}})\right) \end{aligned}$$

It is at this point, that the optimal strategy can be deduced as now the continuation values at all volume levels and at all points in time are known. Departing from the initial volume (that has to be defined), and knowing the (recursively calculated) continuation values for each volume in $\text{t} = 2$ one can deduce the optimal decision in $\text{t} = 1$. The initial volume plus the optimal decision lead to the volume in $\text{t} = 2$, knowing the volume in $\text{t} = 2$ the optimal decision in $\text{t} = 2$ can be deduced which implies the volume in $\text{t} = 3$. Correspondingly one can continue until $\text{t} = \text{T}$, calculating the optimal path of decisions. To calculate the arbitrage value, however, these last iterations are unnecessary, as the highest continuation value in $\text{t} = 1$ by definition already represents the ex post optimal storage value.

In this paper we assume that the storage operator chooses the optimal strategy with full price foresight. This simplification implies an overestimation of the true arbitrage value. In the context of our research (dependence of the arbitrage value on technology, dimensioning and price development) this is less of an issue for three reasons. First, in electricity markets the price spreads as well as the hours with the lowest and highest prices are quite predictable, leading to on average, very modest deviations between a realistic (ex ante optimal strategy, i.e., without knowing the price development in advance) and an ex post optimal strategy.[30] Second, if we demonstrate, that the ex post optimal strategy leads to very different arbitrage values for different technologies, dimensioning

[29] Example: We assume the storage unit described in FN 27. The termination date is 12 p.m., the price at 11 p.m. and 12 p.m. is 20€ and the desired volume is 50 MWh. Thus, the three allowed decisions (0MWh, -1MWh and -2MWh) relate to a present payoff of 0€, 20€ and 40€, the termination volume is 10 MWh, 9MWh and 8MWh and thus the termination payoff is zero for all three decisions. Consequently the last decision (40€ present payoff + 0€ continuation value) is optimal.

[30] Only in cases were price spikes occur in an unexpected single hour (i.e., after the storage has been emptied at the typical high price hour) significant deviations of the ex post optimal (high gain) and the ex ante optimal strategy (average gain) might occur.

and markets – also the ex ante optimal strategy would produce different arbitrage values. And third, some studies such as Sioshansi et al (2008) and Lund et al (2008) have already proven that real operation strategies under imperfect foresight of hourly spot price can capture 85% ~ 90% or more of the potential arbitrage value, depending on the accuracy of the prevision method employed.

3.3 ROIC—indicator of profitability

The optimization function seeks the operation strategies that maximize the payoff of the storage unit (gross profit) disregarding the investment cost or the annual fixed O&M cost. The annual net profit is obtained by subtracting annual fixed O&M cost from the gross profit:

$$\text{Annual Net profit} = \text{Annual gross profit} - \text{Annual O\&}M\ cost$$

The annual fixed O&M cost of each unit is calculated according to:

$$\text{annual O \&}M\ cost = \frac{(\text{Max. charge rate} + \text{Max. discharge rate}) * \text{O\&}M\ cost}{2}$$

The ROIC is then calculated as :

$$\text{ROIC} = \text{present\_value\_Annual Net Profit}/\text{Annualized Investment cost}$$

with annual interest rate=10%

ROIC >1 means the investment is profitable
ROIC<1 means the investment cost is not recovered
ROIC <0 means the cash flow generated by the investment is not even able to cover the annual O&M cost.

Calculating the ROIC for all the possibilities of dimensioning in different markets and under different grid tariff will provide evidence, that the storage arbitrage value is strongly driven by all three factors. Based on this analysis, finally, the most profitable project (i.e. technology and dimensioning) in each market can be selected.

4. Results

4.1 General result.

Table 4 displays the arbitrage value and ROIC for the best and worst dimensioning of each technology in the three spot markets (assuming 5€/MWh of grid tariff). The corresponding annual net profit of these installations varies widely: with -0.4 m € of a CAES (1 hour of maximum charge and discharge duration) in the Nordic market to 8.6 m € of a CAES (8h, 4h) in the Dutch market. The ROIC for all the cases investigated is less than 1, indicating that net present value of the income stream from arbitrage operations covers the investment cost in none of the cases. The ROIC negative, which is the case for all the installations in NordPool, implies that even if the storage unit is offered for free, it is better not to use it for arbitrage in the market, because the price spread in the Nordic market is so small and infrequent that the cash flow generated by arbitrage is not even sufficient to pay back the annual fixed O&M cost. The highest ROIC rate, 81%, is found in APX 2007 for a CAES dimensioned at 8 hours of charge and 4 hours of discharge. It suggests that, in the most favorable case, if the interest rate were below 8% or the investment cost could be reduced by around 14%, the storage unit could eventually break even. Hereafter, we will investigate the results for the three target objectives.

Table 4. Arbitrage values and ROIC for the best and worst dimensioned storage units

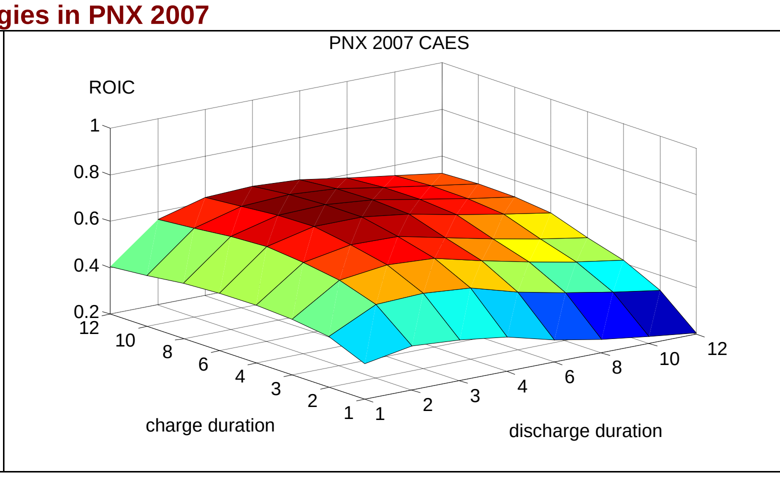
Case		optimal ROIC	optimal annual net profit	charge hours	discharge hours
PNX 2007 CAES	max	72%	7 608 027	6	4
PNX 2007 CAES	min	23%	2 479 835	1	12
PNX 2007 PHS	max	46%	4 890 483	12	8
PNX 2007 PHS	min	10%	1 038 922	1	12
APX 2007 CAES	max	81%	8 562 495	8	4
APX 2007 CAES	min	26%	2 733 386	1	12
APX 2007 PHS	max	55%	5 796 965	12	8
APX 2007 PHS	min	10%	1 103 985	1	12
NORDPOOL 2007 CAES	max	-2%	-154 428	12	12
NORDPOOL 2007 CAES	min	-4%	-406 977	1	1
NORDPOOL 2007 PHS	max	0%	-3 225	12	12
NORDPOOL 2007 PHS	min	-2%	-192 677	1	12

4.2 Sensitivity of ROIC of energy storage unit to its dimensioning

Figure 2 demonstrates impressively that the dimensioning of the installation has an impact on its profitability, as the ROIC of both technologies is distributed in the shape of a tent with more or less steep slope. The optimal layout for a CAES in France for example produces a NPV of -238 m €, while the worst layout losses almost three times as much (-766 m €). The worst technology choice is - apart from two exemptions (see appendix) - to have the shortest allowed charging duration (1h) and the longest allowed discharging duration (12h). This is due to the fact that low prices usually persist for longer hours, while high prices are shorter lived. Besides, the distribution of ROIC does not follow the same pattern for the two technologies. We can infer that different variable and fixed cost components of energy storage technologies lead to very sensitivity of ROIC with respect to the dimensioning.

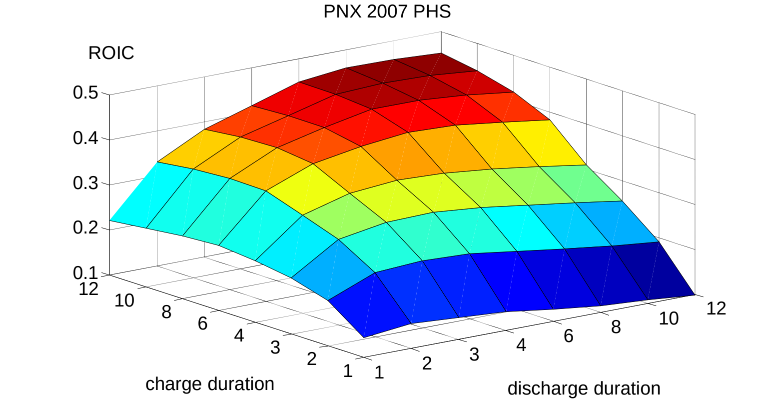
Figure 2. Sensitivity of arbitrage value to storage units' dimensioning for different technologies in PNX 2007

CAES



optimal
ROIC: 72%
charge: 6h
discharge: 4h

PHS



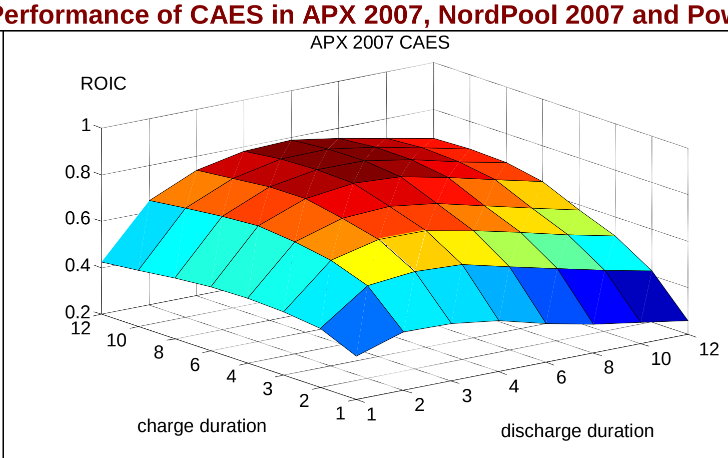
optimal
ROIC: 46%
charge: 12h
discharge: 8h

4.3 Sensitivity of ROIC of energy storage unit to spot price pattern

The results show that for a given storage technology, the optimal ROIC as well as the sensitivity of the ROIC to its dimensioning vary in different markets. Figure 3 compares the performances of CAES in PNX, APX and NordPool spot market during 2007. The optimal ROIC of CAES can be as high as 81% in APX, and as low as -2% in NordPool, confirming that a market featured by high volatility and large price spread (APX) is more favorable for the energy storage units than a market with a flat price pattern (NordPool).

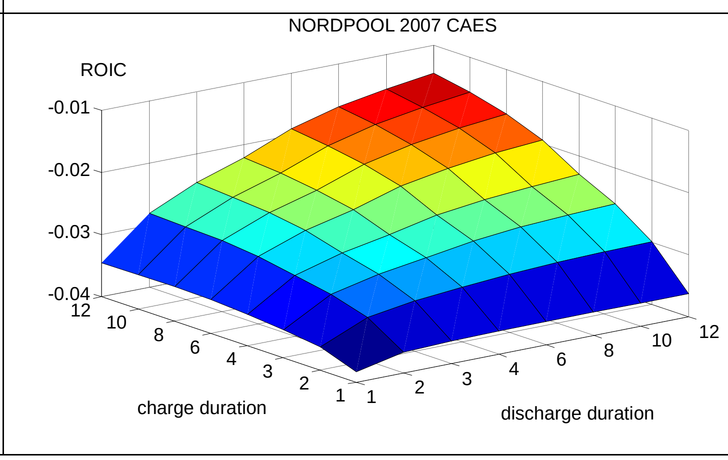
Figure 3. Performance of CAES in APX 2007, NordPool 2007 and Powernext 2007

APX

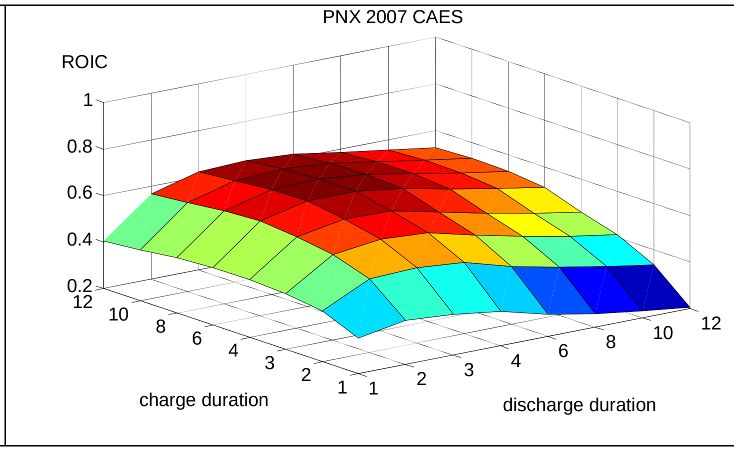


optimal
ROIC: 81%
charge: 8h
discharge: 4h

Nord Pool



optimal
ROIC: -2%
charge: 12h
discharge: 12h

PNX		optimal ROIC: 72% charge: 6h discharge: 4h

Furthermore, the peculiarities of the price developments in the different markets enter in their optimal dimensioning: While the optimal dimensioning in the French and the Dutch market are characterized by medium to long charge durations and comparably short discharge durations, the optimal dimensioning in the Nordic markets for all technologies is the longest allowed charge and discharge duration (see Figure 4). This is due to the fact that intra-daily periodicity and spikes play almost no role in the Nordic markets.

4.4 Sensitivity of ROIC of energy storage unit to grid tariff stipulation

The grid tariff also has a pronounced effect on the profitability of the energy storage units. Table conveys two major messages: first, by reducing the grid tariff from 20 €/MWh to zero, the loss on the CAES investment project is reduced by more than 30%. It suggests that the way how regulators view the energy storage unit (as load or producing source) can greatly influence the development of energy storage technologies in a market environment. Second, as the grid tariff is applied to the amount of energy charged into the storage unit, it also has an impact on the optimal dimensioning of storage units.

Table 5. Changing grid tariff for Powernext 2007 CAES

PNX 2007 CAES	optimal ROIC	optimal annual net profit	Charge hours	Discharge hours
Grid tariff=0€/MWh	**79%**	**8348186**	6	4
Grid tariff=10€/MWh	66%	6958162	6	4
Grid tariff=20€/MWh	**56%**	**5959296**	8	3

5. Conclusion

The deregulation of electric sector gives new roles and new opportunities to energy storage units beyond their traditional functions. Thus, the market value of energy storage technologies is of great importance for their future development. The results of our analysis show that the market value of a storage facility is very sensible to its technical characteristics and different exogenous factors. And more importantly, the endogenous properties of storage facilities can interact with the exogenous economic and regulatory factors in order to maximize the economic value of storage. As exogenous factors change, the optimal design of storage facility may also change. Thus, different technologies can only be compared after the dimensioning of the potential storage units has been optimized according to the market environment. The presented framework to model the arbitrage value can be used to evaluate the impact of other endogenous and exogenous factors (such as efficiency, life cycle, fuel cost, CO2 price, etc) on profitability of energy storage units.

The results of our analysis also show that the market value alone is not sufficient to justify the investments on any storage unit in our analysis. This is partly due to the fact that the eventual “regulated” revenue of storage units is not taken into account in our method. In countries where capacity mechanisms co-exist with the spot energy market, the revenue from regulated services can be an important part to recover the investment.[31] Considering the arbitrage behavior of an electricity storage unit, it contributes to the balance of the electric system just as a peaking unit, except that it consumes the cheap electricity instead of fuel to produce electricity during peak period. In this sense, the electricity storage units should be eligible to receive revenue from the capacity mechanism. As capacity mechanisms vary from market to market[32] the “capacity revenue” for electricity storage need to be accessed on a case by case basis. A sensitivity analysis of economic value of electricity storage with respect to different capacity mechanisms could be undertaken in future research.

[31] The PJM State of market report 2006 shows that the average capacity related revenue (during the year 1999-2005) is about half the amount of energy and ancillary services revenue for a peaking plant.

[32] For instance, PJM ISO features capacity credit market, New England implements forward capacity market, Norway establishes regulating capacity option market (RCOM), Spain is migrating from capacity payment to reliability options, etc.

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