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Electric storage technologies for the future power system – An economic assessment

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***Abstract*— The paper analyses different electric storage (ES) technologies for power system applications from an economic perspective. After giving a brief overview on different technology options, a model-based assessment is performed. The model simulates optimal market-based storage operation in order to maximize revenues from energy arbitrage. The results indicate that pump hydro storages (PHS) are the best option from an economic perspective. However, the results show that revenues from storage operation have decreased in the last years. Currently, not even PHS would generate sufficient revenue to be a profitable investment. That points out, that even though demand for storage capacity is expected to increase with higher shares of renewable electricity (RES-E) in the future, there are no economic incentives to extend storage capacities at the current framework conditions.**

***Index Terms*—electricity storage, technologies, economic assessment, energy arbitrage, control reserve,**

I. Introduction

The European Union is currently driving an effort to increase the share of renewable electricity (RES-E) in order to reduce carbon emissions in the power sectors [1]. The development has led to considerable shares of new renewables in countries like Germany and Austria, and a further increase is expected for the upcoming years and decades. However, higher shares of fluctuating RES-E production are a great challenge for the power system. They require more flexibility of conventional power plants to cover the residual load and higher transmission capacities to balance supply and demand in wider areas [2]. In addition extension of electric storage (ES) can help to balance fluctuations in renewable production both on a local and on a regional level.

In the power system there are different categories of ES, in terms of size and function, with different technology options for each of them. This paper focusses on large-scale bulk ES. Some of their important application fields in the power system are energy arbitrage, provision of ancillary services (e.g. black start capabilities), frequency regulation and spinning reserve [3].

This paper provides an economic assessment of ES in Austria, comparing different technology options. Thereby, the paper tries to give answers to the following questions:

- What are the economic perspectives of new built ES plants in Austria today?
- Which are the best technology options?
- What are the key factors that affect economy of ES?
- What are the future perspectives with respect to investment in ES plant?

The problem is approached as follows: First, a brief overview on techno-economic parameters of different ES technologies is provided. Based on this data a model-based economic assessment is performed. The applied model defines optimal operation of the ES in order to maximize revenues. By simulating real storage operation, the model provides a good insight in the key factors for economic storage operation and thereby, contributes to a better understanding of this matter.

The remaining paper is structured as follows:

Section II gives an overview on technical and economic parameters of the analyzed ES technologies. Section III presents the methodology of the economic assessment and the storage model. Section IV explains the relevant economic framework conditions in Austria that are used for the assessment. In section V the results of the assessment are presented and in section VI conclusions are drawn.

II. Electric Storage Technologies

For the analysis only technologies suitable for bulk ES operation in the power system are considered. This section briefly presents each of them and compares their technical and economic characteristics:

A. Pumped hydro storage PHS

In pumped hydro storages (PHS) energy is stored by using electricity to drive pumps that lift water to a reservoir at higher altitudes. For discharging this process is reverted and the water from the reservoir drives turbines and generators that convert the energy into electricity.

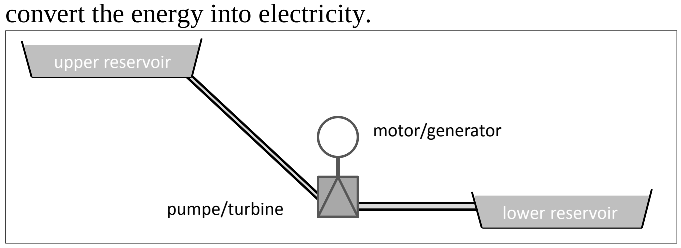

Fig. 1. Schematic diagram of PHS

Modern PHS can reach efficiencies of up to 85 % in the total cycle [4]. The technology is mature since it has been used for decades with considerable power installed on a global level [5]. Due to its relatively short response time PHS can be used for energy arbitrage and also provide regulation control. The main problem of the technology is the fact that suitable sites to build such a plant are limited and often apart from actual demand centers.

Investment costs of PHS range from 500 €/kW to 1500 €/kW [4] [5]. However, there are also sources that estimate considerably higher cost of up to 3000 €/kW [3]. The range of costs is mainly due to the different conditions on the site of the plant and different energy storage capacities. Hence, it is difficult to define a general value for investment costs. According to the data provided by [5] the mean value of PHS for day storage operation is about 750 €/kW. Naturally, investment costs also depend on the storage capacity installed.

Therefore an approach where both components are considered is applied:

$$IC_{total} = ic_{power} \cdot C_{power} + ic_{capacity} \cdot C_{capacity} \qquad (1)$$

Where ic_{power} and $ic_{capacity}$ are the power- and energy-related specific investment costs, that are used to estimate investment cost of a PHS with power rate C_{power} and an energy storage capacity $C_{capacity}$. (see table II)

B. *Adiabatic compressed air energy storage (AA-CAES)*

Compressed air energy storage (CAES) plants use the potential energy of compressed air to store electricity. The electricity is used to drive compressors that compress the air at high pressure to store it either in pressure vessels or in geological formations (e.g. salt caverns). When released, the compressed air is used to drive turbines that generate electricity. There are two types of compressed air ES plants: diabatic (CAES) and adiabatic plants (AA-CAES). In diabatic plants natural gas has to be co-fired while discharging to keep temperature in the turbine high during expansion of the air. In AA-CAES the heat accumulated during compression is reused for this purpose. Hence, an AA-CAES consists of a compressed air storage and a thermal energy storage system, making the technology more complex and costly but also more efficient. Cycle efficiency of the AA-CAES reaches up to 70 % whereas the CAES has only 50 % [6].

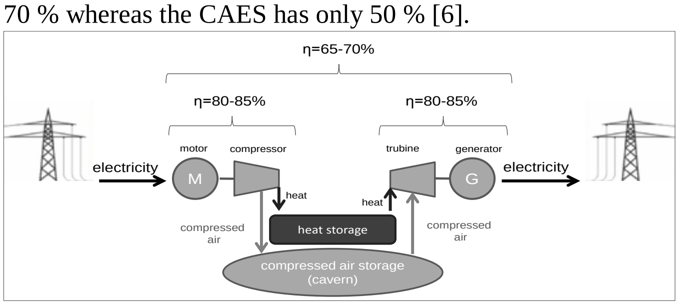

Fig. 2. Schematic diagram of AA-CAES

Globally there are currently only two diabatic CAES plants in operation [7] while AA-CAES are still in a conceptual phase [8]. Large scale CAES rely on the availability of geological formations (e.g. salt cavern) that are suitable in size and durability for storage operation. Potential sites where a CAES can be installed are therefore limited.

Investment costs of AA-CAES had to be estimated, since no large scale projects have been realized so far. Estimated costs for diabatic CAES range from 500 €/kW to 800 €/kW [7][6][9]. Similar to the PHS total investment costs are estimated using a power- and an energy-related cost component (see table II).

C. *Sodium Sulfur (NaS) Batteries*

Sodium sulfur batteries have been used for power system applications in japan for several years and can be considered a mature technology. They offer good cycle efficiency (≈ 75%) and high cycle-life (≈2000-3000 cycles) [10][9][3][11]. One major disadvantage of the technology is the high standby-losses due to the required operation temperature (300-350°C) [4]. Their storage capacity-related investment costs range from 200 to 500 €/kWh [10][12][9].

D. *Vanadium Redox Flow (VRF) Batteries*

The vanadium redox flow (VRF) battery consists of two electrolyte reservoirs and a reactor unit. When charged or discharged the electrolyte is pumped to the reaction unit. Therefore, the power of the systems depends on the reaction unit, the electrochemical cell, whereas the storage capacity depends on the volume of the electrolyte reservoirs. This layout makes the systems very flexible for different applications.

The cycle efficiency of the redox flow batteries is around 75 % and the cycle life accounts for approximately 3000 cycles [10][9][7]. Estimations of specific investment costs, found in literature range from 200 to 1000 €/kWh [4][10][9] [13].

E. *Lithium Ion Batteries*

Lithium Ion batteries are a relatively new technology in the field of power systems applications. Due to their high energy density they are widely used in portable electronics. However, their excellent cycle efficiency of over 90 % [10] and high cycle life (≈3000 cycles) also makes them attractive for power systems applications. Their main disadvantage is their high costs, with specific investment costs ranging from 500 to 1500 €/kWh [10][9][4][3]. In the past years much progress in the field of Li Ion batteries has been made, leading to considerable cost reductions and the current efforts of the battery industry in this field are expected to lead to further reductions.

F. *Hydrogen Storage*

In hydrogen storage systems electricity is converted into hydrogen via electrolysis. The hydrogen is then stored either in pressure vessels or in suitable geological formations (e.g. salt caverns). To reconvert the stored energy into electricity hydrogen is fired in thermal power plants (e.g. a gas and steam plant). With 30-40 % the efficiency of the storage cycle is relatively low. So far no large scale plant has been realized. This is why investment costs had to be estimated based on the system components (using figures found in [9] [14] & [15]).

(see table I).

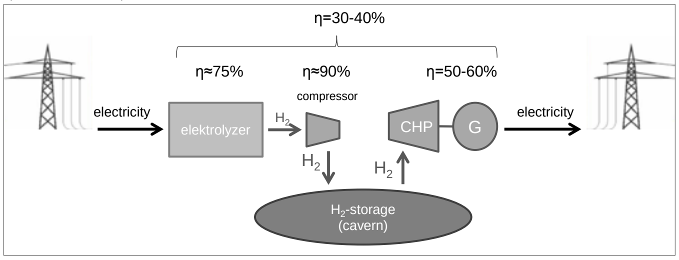

Fig. 3. Schematic diagram of H_2-storage system

G. *Renewable methane storage (RES-E-CH₄)*

Another approach to store electricity is the conversion into methane. In a first step electricity is converted into hydrogen, which is then turned into methane by adding CO_2. The methane can be fed in the natural gas grid, respectively natural gas storage facilities can be used for storage. The reconversion to electric power is done by conventional gas and steam plants.

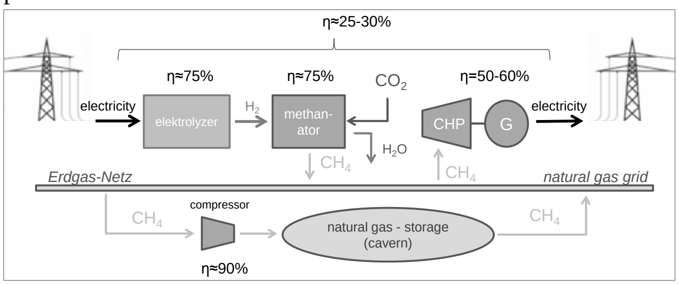

Fig. 4. Schematic diagram of H_2-storage system

Since no large scale plant has been realized so far, there is some uncertainty concerning the cycle efficiency that can be achieved. In this analysis cycle efficiency is estimated to be in the range of 25-30 % derived from the figures found in [16]. The main advantage of the concept is the fact that most components of the storage system (natural gas grid and storage, gas and steams plants) already exist. Thus, the technology can be easily integrated in the structure of the existing power system.

Investment costs of a large scale methanation facility can only be estimated at this point (see table I).

TABLE I
INVESTMENT COSTS OF RENEWABLE METHANE STORAGE COMPONENTS

component		specific costs	source:
elektrolyzer	[€/kW]	1000	[9]
methanator	[€/kW]	1000	own estimation
compressor	[€/kW]	160	[14] & [15]
CHP Plant	[€/kW]	550	[9]
storage H2(salt cavern)	[€/kWh]	0.5	[9]
storage CH4(salt cavern)	[€/kWh]	0.5	derived from [9]

H. *Technology Overview*

Figure 5 shows the ranges of storage efficiency for the analyzed technologies: In the assessment values in the upper band of these ranges are used in order to represent the latest state of technology. Table II gives the assumed parameters of the analyzed storage technologies.

Another relevant aspect that has not been addressed so far is the response time. The response time is the time it takes for the electricity from the storage to be available and thus it defines which functions the storage can fulfill and consequently where it can generate revenues (see table III). Maintenance costs of PHS and CAES are set according to [17] & [18]. Maintenance costs of other technologies are estimated.

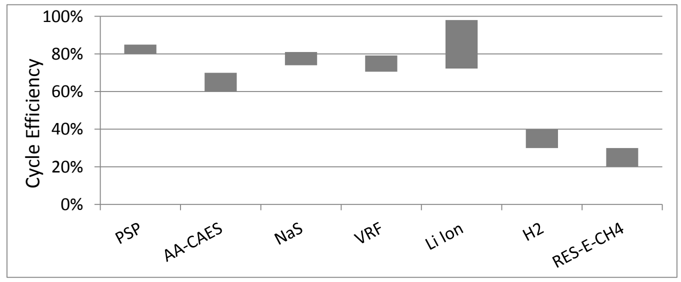

Fig. 5. Cycle efficiency of storage technologies

III. METHOD OF APPROACH

In the economic assessment technologies are analyzed from an investor perspective. Thereby, the storage project is seen as a single project without considering benefits and costs savings of the storage to the system as a whole. Hence, only direct revenues from the plant are used as a basis for the investment decision. This approach corresponds to the given framework conditions in Austrian where ES plants are privately owned and sell their services in a market environment.

In this section an insight in economic operation of electric storages is given. First the general correlation of revenues and costs of storage operation is presented and the technology-specific differences are outlined. Secondly, the storage model that is used to simulate market-bases operation is presented. Thirdly, relevant economic framework conditions for ES are described.

A. *Costs and revenues of storage operation*

The profit of the ES plant G is defined by the revenues as derived from optimal peak-off peak arbitrage operation $R_{p\text{-}o}$, revenues from ancillary services R_r, capital costs C_c and maintenance costs $C_{o\&m}$.

$$G = R_{p-o} + R_r - C_c - C_{o\&m} \qquad (2)$$

G … *profit [€/year]*
$R_{p\text{-}o}$ … *revenues from peak/off-peak spread [€/year]*
R_r … *revenues from ancillary services [€/year]*
C_c … *capital costs [€/year]*
$C_{o\&m}$ … *operation and maintenance costs [€/year]*

As indicated by equation 2 there are different types of revenues that can be generated through storage operation. With energy arbitrage, the ES uses the spread in the spot market price between peak- and off-peak hours to generate revenues. Thereby, revenues depend on the course of energy prices during the time period and the efficiency of the storage (see equations 3).

$$R_{p-o} = f(p_{e(t)}, \eta_s) \qquad (3)$$

p_e … *electricity spot market price [€/MWh]*
η_s … *storage efficiency [%]*

TABLE II
ASSUMED PARAMETERS FOR STORAGE TECHNOLOGIES

		PHS	AA-CAES	NaS	Redox-Flow	Li-Ion	hydrogen storage	methane storage
Efficiency charging	[%]	92	84	87	87	92	68	50
discharging	[%]	92	84	87	87	92	50	50
Response time		minutes (standing) seconds (spinning)	15 minutes (cold start)	milli-seconds	milli-seconds	milli-seconds	according to CHP plant operation	according to CHP plant operation
Investment costs								
capacity specific	[€/kW]	500	600				1000*	2000*
energy specific	[€/kWh]	30	70	200	200	400		
O&M costs	[€/kW/year]	4	4	8**	8**	8**	4**	4**
Depreciation time	[years]	25	20	10	10	10	20	20
Applications (technically feasible)								
energy arbitrage		✓	✓	✓	✓	✓	✓	✓
primary control reserve		✓		✓	✓	✓		
secondary control reserve		✓		✓	✓	✓		
tertiary control reserved		✓	✓	✓	✓	✓		

*only electrolyzer and mathanator considered **estimated

One economic criterion for the storage to operate is that its efficiency has to be greater than the ratio of acquisition and sales price of electricity (see equation 4) [19].

$$\eta_s \geq \frac{p_{in}}{p_{out}} \tag{4}$$

η_s … *storage efficiency*
p_{in} … *electricity acquisition price [€/MWh]*
p_{out} … *electricity sales price [€/MWh]*

For battery systems equation 3 has to be complemented by adding storage costs:

$$R_{p-o} = f(p_{e(t)}, \eta_s, C_{bat}) \tag{5}$$

C_{bat} … *specific battery cost [€/kWh]*

Since batteries have a maximum cycle life degradation cost C_{bat} of a single cycle can be defined as

$$C_{bat} = IC_{bat} \cdot {Z_{bat}}^{-1} \tag{6}$$

IC_{bat} … *battery investment costs [€/kWh]*
Z_{bat} … *cycle life of batteries [cycles]*

In addition to energy arbitrage the storage can generate revenues from ancillary services, for example by providing control reserve. A closer view on this option will be taken in section IV.

Capital costs are calculated using the capital recovery factor defined by the technology specific depreciation time (see table III) and an interest rate of 7 %.

$$CC = IC \cdot CRF \tag{7}$$

$$CRF = \frac{r \cdot (1+r)^{DT}}{(1+r)^{DT} - 1} \tag{8}$$

CC … capital costs [€/MWh/year]
IC … investment costs [€/MWh]
CRF … capital recovery factor
r … interest rate [%]
DT … depreciation time [years]

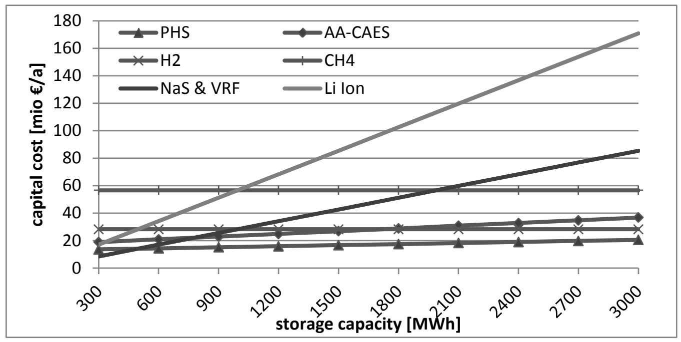

Fig. 6. Yearly capital costs of a 300 MW storage plant as function of its energy storage capacity for different technologies

In the analysis an ES with a power rate of 300 MW is considered, which is an average size for generation units in Austria. Capital costs for plants are often expressed in €/kW. However, it is evident, that energy storage capacity also affects investment costs. The corresponding correlation for a 300 MW plant is illustrated in Figure 6. For the PHS and the AA-CAES investment cost is defined by a power rate- and a capacity-dependent cost component as described in section II. Cost of batteries increase linear with increasing storage capacity, since both depend on the number of cells that are installed. For hydrogen and RES-E CH_4 storages there is no considerable capacity dependence of capital costs. Both technologies can use existing infrastructure, namely the natural gas grid, with abundant storage capacity. Hence, marginal increase of capacity cost can be neglected here. It has to be mentioned that even though feeding hydrogen into the natural gas grid is technically possible, there are regulatory barriers that would have to be overcome first. In case of using a dedicated storage vessel for hydrogen, e.g. a salt cavern, there would be a capacity-dependent cost component as well.

B. Storage Model

Optimal storage operation is simulated using a linear optimization model implemented in General Algebraic Modeling System (GAMS). The model is simplistic as it represents only the basic operation functions: charging; discharging; idle mode. It determines the optimal storage operation schedule in order to maximize revenues from peak/off-peak arbitrage using historic yearly electricity price data:

Objective function:

$$\max[R_{p-o}] \quad with$$

$$R_{p-o} = \sum_t (p_{(t)} - c_l) \cdot P_{out} - (p_{(t)} + c_l + c_g) \cdot P_{in} \qquad (9)$$

p … electricity price [€/MWh]

c_l *… grid loss fees [€/MWh]*

c_a *…variable grid connection fees [€/MWh]*

P_{in} *… electric storage input [MW]*

P_{out} *… electric storage output [MW]*

With battery technologies this equation is slightly different. Since they have a maximum cycle life, their investment cost can be expressed in €/kWh stored electricity. In this case investment cost would have to be considered in the objective function to assure that they are considered in storage operation.

Objective function for battery storages:

$$\max[R_{p-o}] \quad with\ \mathrm{R}_{p-o} = \sum(p_{(t)} - c_l) \cdot P_{out} - (p_{(t)} + c_l + c_g) \cdot P_{in} - P_{out} \cdot C_{bat} \qquad (10)$$

State of charge of the storage is defined as follows:

$$C_{(t)} = C_{(t-1)} + P_{in} \cdot \eta_{in} - P_{out} \cdot \eta_{out}{}^{-1} \quad with \qquad (11)$$

$$0 \leq C \leq C_{max} \qquad (12)$$

$$0 \leq P_{in} \leq P_{max} \qquad (13)$$

$$0 \leq P_{out} \leq P_{max} \qquad (14)$$

C … state of charge [MWh]

η_{in} *… charging efficiency [%]*

η_{out} *… discharging efficiency [%]*

C_{max} *… state of charge [MWh]*

P_{max} *… maximum electric input or output [MW]*

It is evident that the model does not capture all technology specific abilities and characteristics. However, its accuracy is sufficient to answer the specific questions posed in this paper. It can simulate energy arbitrage operation of all analyzed technologies and determine their maximum yearly revenues.

Providing ancillary services is not considered in the model algorithm. Due to the complexity of the market mechanisms for these services, revenues are highly uncertain and can only be estimated at this point. (see section III C).

IV. Economic Framework Conditions

This section provides a brief insight in the economic framework conditions for ES in Austria. It starts with a description of the domestic power supply structure and proceeds with a short introduction on the relevant markets where ES can generate revenues depending on their technical characteristics.

A. The Austrian Power System

The following figures should give a brief overview on the structure of the power sector in Austria. They all apply for the year 2010:

Power supply in Austria is dominated by hydro power plants. Capacity of run-of-river plants adds up to 5.2 GW accounting for 25% of total capacity installed and 41 % of yearly power production. Hydro storage plant capacity adds up to 7.5 GW or 37 % of installed capacity and 20 % of yearly production. Total pumping capacity of PHS in Austria is 2.9 GW. Thermal power production in Austria has a capacity of 6.3 GW (31% of installed capacity) and accounts for 32 % of annual production. Other RES-E sources have increased considerably in the last decade an account for 7 % (1.5 GW) of installed capacity and 7 % of yearly production. Most important technologies are wind (1 GW) and biomass (0.4 GW) whereas PV still plays a minor role (0.1 GW) (Data source: [20]).

B. Electricity Spot market

The main function of storages in the power system is to balance intermittent power generation. This is typically done by energy arbitrage operation, where the storage generates revenues by using the spread between peak and off-peak prices. In this case fees for grid-use and losses have to be paid in Austria which add-up to approximately 3 €/MWh in a storage cycle [21]. To simulate this kind of operation EXAA spot market prices are used. The EXAA market area includes Austria and Germany and clearing prices are strongly correlated to EEX/EPEX clearing prices. Because of its much higher power demand and production capacity, price formation on these spot markets is dominated by the German power sector.

For the assessment of storage technologies 2009 prices are used. Figure 7 shows examples of the weekly run of EXAA clearing prices for a December and a July 2009 week.

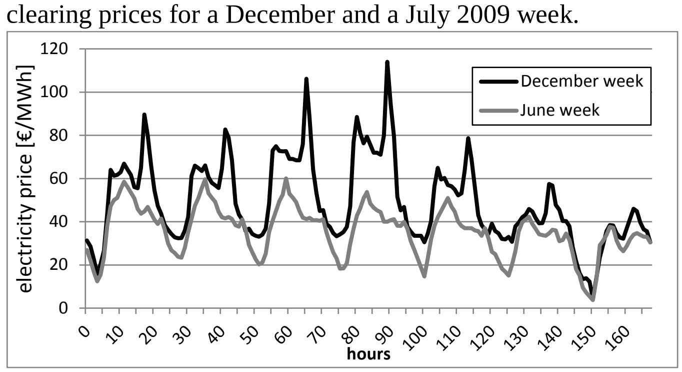

Fig. 7. Electricity prices for selected weeks in December and June 2009 (Date Source: APCS 2011)

C. Control reserve

Provision of control reserves is another option for ES to gain revenues. In the European transmission network control actions are organized in three steps: primary control, secondary control, tertiary control.

For provision of control reserve a certain range of power (positive or negative) has to be reserved that can be called by the network operator if needed. For primary control power has to be available within a few seconds and maintained for up to 15 minutes. Secondary control hast to be provided within 5 minutes and maintained up to an hour, while tertiary control has to be available after 15 min and last for up to couple of hours [19] [22].

In the control area APG the network provider organizes calls for bids for all three types of control reserves. In the clearing process offers are ranked by height of the price of offered power until power demand of the control area is met (pay-as-bid). For secondary and tertiary the bids also have to include energy prices that are used as a basis of their dispatch in cases of control incidents (merit-order).

Electric storages can provide control reserve depending on their technical performance. An overview on the technical qualification of different technologies is given in table III in section II.

In principle an ES plant can participate in all control markets when it is technically qualified. However, primary control is not that interesting since generation units have to reserve positive and negative reserve at the same time, which is a serious limitation to storage operation. Moreover, required primary power capacity for the control area APG is only +/– 70 MW (2012 [23]) which is usually covered by spinning generation units.

Tertiary control is not that attractive either from an economic perspective: power demand for tertiary reserve defined by APG in 2012 is +280 MW and –125 MW ([23]), but dispatch probability for bid capacity is low (≈0.5-1.5 %) according to the market statistics of the years 2007 to 2011 (data source [24]).

The most attractive control reserve type for storages is secondary control: Power demand in APG control area is +/– 200 MW (2012 [23]) with a relatively high dispatch probability (≈15-20 %) (data source [24]). Hence, market volume for secondary control is significantly higher than for the other types.

To estimate possible from provision of control reserve in an economic assessment of a future storage project the competitive situation within the control area has to be considered as well. Given only the current total power rating of all hydro- and pump hydro storages in the APG control area (turbines: ≈ 7.5 GW; pumps: ≈ 2.9 GW) and the high market concentration (three biggest players accounting for 74 % of storage turbine capacity and 87 % of pump capacity) it is obvious that auctions of control reserve will be highly competitive. Consequently, revenues from control markets, if any, would be low and uncertain.

V. Results

The model described in section III is used to assess storage technologies at economic framework conditions in Austria. First a 300 MW PHS plant, which is the current benchmark technology with many plants realized in Austria, is analyzed. Thereby, potential effects of this additional ES capacity on electricity spot market prices and thereby on the profitability of ES as described in [19] and [25] are neglected. Using the storage model yearly revenues are determined assuming different storage capacities based on spot market prices of the years 2007 to 2011. Figure 8 shows the corresponding yearly revenues as a function of the assumed maximal storage capacity. The dashed line indicates the capital costs for a PHS plant with a fixed part depending on the power rating of the plant (500 €/kW) and variable part depending on the storage capacity (30 €/kWh) as described in section II. The figure indicates that revenues from storage operation have decreased considerable in the past years. After growing by about 15-20 % from 2007 to 2008 they have decreased constantly the years after. Revenues in 2011 are about 60 % lower than in 2008. These figures clearly show the uncertainty of storage revenues. Especially the downward trend from 2008 to 2011 appears discouraging with respect to future investment in storage projects since revenues in the years 2009-2011 have been below estimated yearly capital costs of a new plant.

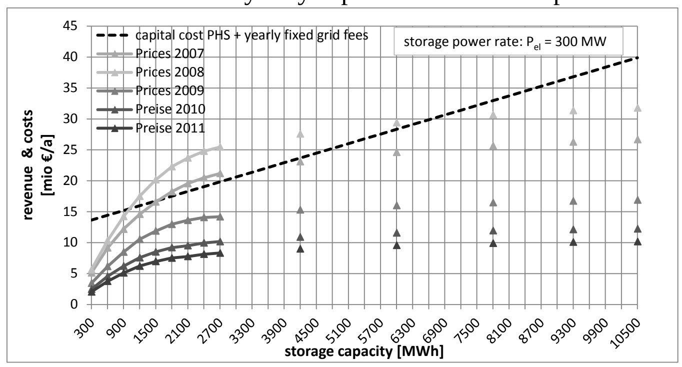

Fig. 8. Yearly revenues and capital costs of a PHS as function of the storage capacity in the years 2007-2011

Another relevant finding from that figure is the optimal storage capacity at the assumed power rating. Taking all analyzed years and the defined capacity cost, optimal storage capacity would be between 2000 and 2500 MWh, which is a typical size for day storage operation.

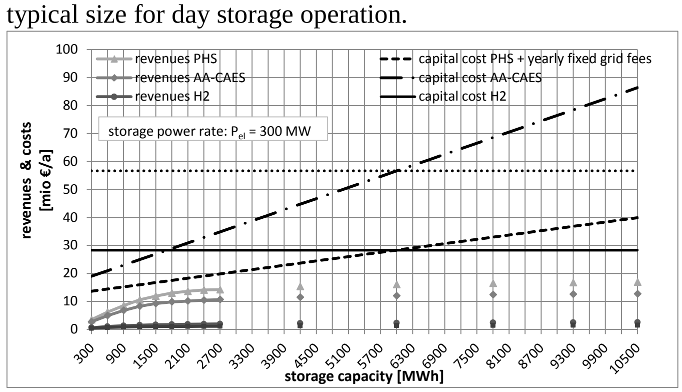

Fig. 9. Revenues and capital costs of different technologies as function of the storage capacity based on electricity prices 2009

Besides PHS also other storage technologies are analyzed based on the 2009 electricity prices. Figure 9 compares capacity-dependent yearly revenues of the PHS, the AA-CAES, the H_2 storage and the RES-CH_4 storage. It shows that yearly revenues are below the estimated capital costs for all technologies. At the 2009 prices, none of these options would be an economically attractive investment. The figure also illustrates that revenues are correlated to the storage efficiency of the technology. At a storage capacity of 2100 MWh the PHS (η_s=80%) generates yearly revenues of € 16.1 mio and the AA-CAES (η_s=70%) 12.1 mio €, whereas less efficient technologies such as the H_2- (η_s=34%) and the RES-CH_4-storage (η_s=34%) generate only 2.3 and € 1.3 mio which is far below their estimated yearly capital costs.

To understand these differences in revenues a closer look on their daily operation schedule has to be taken. Figure 10 and Figure 11 compare storage operation of analyzed technologies in a December (December 14-20, 2009) and a June week (June 15-21, 2009). The technology-specific differences are evident. The PHS and the AA-CAES show a very similar profile. However, even the 10 % difference in efficiency affects storage operation. The PHS has more operation hours and uses the total capacity also during summer weeks. For the H_2- and the RES-CH_4-storage the operation schedule is fundamentally different. Because of their low efficiency they can hardly use daily price spreads for daily cycles. Hence they rather operate in week storage schedule accordingly generating less revenue.

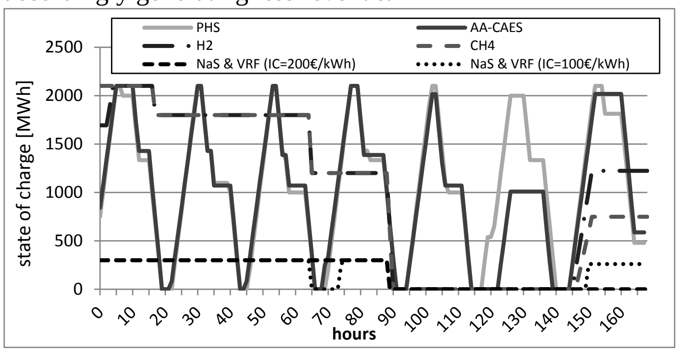

Fig. 10. Weekly storage operation of different technologies (December 14-20, 2009)

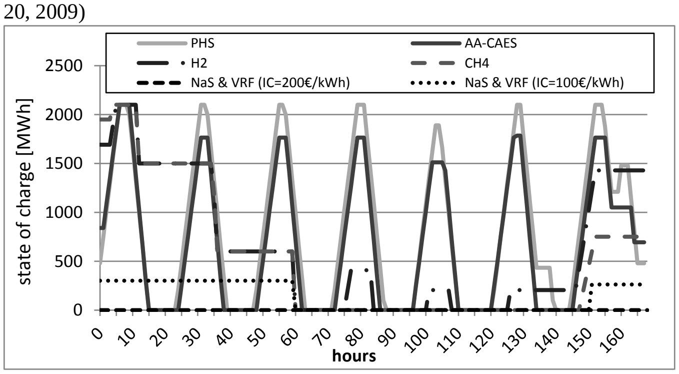

Fig. 11. Weekly storage operation of different technologies (June 15-21, 2009)

Because of the high capacity-specific investment costs of batteries a low capacity to power ratio is preferable. For the analysis a storage capacity of 300 MWh is assumed for the 300 MW power rating system. For batteries operation is defined not only by cycle efficiency, but also by their specific costs (see section III). For VRF- and NaS-batteries storage cost would be 95 €/MWh with current, optimistic estimations of specific investment costs of 200 €/kWh, respectively 47 €/MWh if specific investment costs would decrease to 100 €/kWh in the future. Storage operations for both cases are depicted in figure 10 and 11 for a December and a July week. It shows that even though cycle efficiency is high ($\eta_s \approx 75\%$) the battery would only make 0.5 to 2 cycles in this week depending on the specific costs assumed. This indicates that price spreads in the electricity spot market are too small to operate batteries in energy arbitrage.

In addition to ES for daily and weekly operation a closer look on potential seasonal storage technologies is taken. The discontinuous availability of renewable electricity throughout the season asks for huge storage capacity. This means that, technologies with low capacity-dependent investment costs are preferred for this task. Looking at the capacity dependence of capital costs (see figure 6) it is obvious that H_2 and CH_4 would be potential candidates. On a favorable site with low investment cost even a PHS would be possible. To assess their economic potential seasonal operation is simulated for 300 MW power rate and unlimited storage capacity.

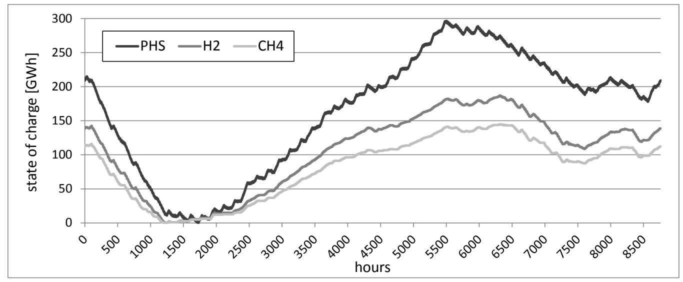

Fig. 12. Yearly storage operation of technologies with seasonal storage operation (2009)

Figure 12 shows seasonal storage operation of PHS, H_2 and RES-E-CH_4. The charts again indicate the effects of storage efficiency on the operation schedule. The higher the efficiency the more energy is stored throughout the year and the more weekly and daily cycles are done during the seasonal cycle. Table IV shows the yearly revenues of the three technologies and the derived economically feasible specific investment costs. It shows that estimated investment costs of all three technologies (see table I, II & III) are currently far above the feasible investment costs.

TABLE IV
RESULTS FOR SEASONAL STORAGES

	revenue [mio €/year]	max. capacity used [GWh]	derived maximum investment costs [€/kW]
PHS	22,7	297	801
H2	5,0	187	178
CH4	2,8	145	98

VI. Conclusions

The results of the analysis show that investment in electric storage has become less attractive in Austria throughout the past five years. In fact revenues from energy arbitrage of PHS have dropped by about 60 % in this time frame. There are different potential reasons for this development in the EXAA market area. New PHS capacities have gone online during this period that have led to a more even run of spot market prices. Also the generation mix could have affected the run of the spot market prices. For example the increasing PV production leads to a lower price during summer peak hours. This so called merit-order effect has been described in various studies e.g. [26]. As addressed in section IV the power spot market prices on the EXAA are formed mainly by the German power sector, where PV capacities have increased significantly in the last years. Also the structure of base load production has an effect. Due to end-of-life shut-down of base load generation blocks (e.g. German nuclear plants) base load prices tend to increase, which also cuts revenues in energy arbitrage.

The results of the technology assessment show that PHS are still the best option from an economic perspective. They have higher efficiency and lower costs than the other analyzed options. Especially for Austria, where potential sites are available, they will remain the first choice in the future. The fact that not even PHS are an attractive investment at current electricity prices show how difficult it will be for other technologies to enter the market.

Provision of control reserve is not likely to improve that situation considerably in the EXAA market area. At the given framework expected revenues are small and uncertain, due to a limited total market volume and strong competitions by existing hydro- and PHS plants.

Building new storage plants is a capital intense long term investment with long planning and construction phases. Past years' development has shown how fast framework conditions can change. Expected future trends such as increasing RES-E production and the shut-down of German nuclear plants mean further uncertainties. This leads to the conclusion that even though the energy system will require storage capacities to cope with renewable production, there are currently no economic incentives to get storage projects on track at the given framework conditions.

VII. References

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