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Centralized and Decentralized Compressed Air Storage for Enhanced Grid Integration of Wind Power

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Abstract:

In this paper, we model the economic feasibility of compressed air energy storage (CAES) to improve wind power integration. The Base Case is a wind park with 100 MW of installed capacity and no storage facility. In Variant 1 we add a central CAES system with 90 MW of compressor and 180 MW of generation capacity. The compressed air is stored in a cavern. The CAES system is operated independently of the wind park such that profits from peak power sales at the spot market and reserve power market are maximized. Variant 2 is an integrated, decentralized CAES system, where each wind turbine is equipped with a compressor but no generator. The compressed air is stored in a cavern and converted into electricity by a turbine, again maximizing profit as a peak power plant. Both variants are modeled for conventional diabatic and the more advanced adiabatic systems.

Keywords: Compressed air energy storage, CAES, Wind energy, Reserve market

1. Introduction

Increased use of wind energy is a challenge due to the intermittent nature of wind power and local concentration of power generation, requiring an extension of both the grid and energy

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storage systems in order to maintain the security of electricity supply. For applications with low utilization rates, such as emergency power supply units, the investment costs per unit of power are of great interest. In contrast, for applications to balance fluctuations in wind power production at high utilization rates, the relevant parameter is the investment cost per unit of storage capacity. In this respect compressed air energy storage (CAES) has a high economic potential and can thus play an important role, especially in the light of lacking alternatives. One such alternative is pump storage hydro power, which due to its existing utilization often has only limited remaining potential for exploitation. It is thus not very surprising that analysis of CAES has received increasing attention in the scientific community in recent years (e.g. Zunft/Tamme, 2005; Greenblatt et al., 2007; Hall/Bain, 2008; Lund et al., 2009; Zafirakis/Kaldellis, 2009).

In this paper, which is based on a more detailed study undertaken in Latz (2008), we model the economic feasibility of CAES to improve wind power integration for the case of Germany. The Base Case is a wind park with 100 MW of installed capacity and no storage facility. In Variant 1 we add a central CAES system with 90 MW of compressor and 180 MW of generation capacity. The compressed air is stored in a cavern. The CAES system is operated independently of the wind park such that profits from electricity sales at the spot market and reserve power market are maximized. Variant 2 is an integrated, decentralized CAES system, where each wind turbine is equipped with a compressor but no generator. The compressed air is stored in a cavern and converted into electricity by a turbine, again maximizing profit as a peak power plant. We consider both conventional diabatic (CAES) with a total process efficiency of 54% and the more recently developed advanced adiabatic (AA-CAES) systems (Althaus, 2006) with a total process efficiency of about 70%.

The role of CAES power plants for trading in the spot market and minute reserve market deserves some separate explanation. In principle, CAES systems can help to better accommodate the feed-in of volatile wind power generation into the grid. A profit-maximizing operator of a CAES system will try to fill the storage at minimum cost and to maximize revenues from selling the electricity produced with the storage system to the grid, acting as a trader of electricity. Since CAES systems aim at exploiting the arbitrage opportunities from short-term fluctuations of the electricity price, the spot market (rather than the futures market) is the market of choice. In the spot market day-ahead and intra-day contracts are traded. The day-ahead market allows the trading of single-hour contracts, thus enabling CAES operation planning on an hourly basis. For the day-by-day planning of the CAES operation, spot market price forecasts are required. In case of deviations between the actual and forecasted spot market electricity price, adjustment of the operation plan are possible during operation by acting on the intra-day market (at the German EEX in Leipzig, for instance, single-hour contracts can be traded on the intra-day market up to 75 minutes before delivery on the same day; cf. www.eex.com). Another option for CAES power plants is trading on the minute reserve market. In Germany, this market is operated via a joint platform of the grid operators (cf. VDN, 2005). Products traded include primary and secondary balancing energy and minute reserve. Since the provision of primary and secondary balancing energy is made for periods of six months and has to be effected within one minute, only minute reserve is relevant for CAES plants. Positive or negative minute reserve is traded on the day-ahead market for intervals of four hours on the next day, and has to be provided within 15 minutes (full power), which is feasible for CAES plants (Mellies, 2005). Positive minute reserve means that the provider has to provide contracted load to the grid if the grid operator calls the reserve, while in the case of negative minute reserve the provider has to take the contracted load from the grid (either by consuming electricity or by reducing the feed-in). Conventional diabatic and adiabatic CAES power plants have three options: (1) to offer positive minute reserve during compressor operation times (the compressor power is reduced and the energy contracted from the spot market for operating the compressor is instead supplied to the grid as minute reserve); (2) analogously, negative minute reserve by reducing the turbine power during turbine operation; and (3) if the CAES power plant is not in operation, both positive (turbine is switched on) and negative (compressor is switched on) minute reserve can be offered. Wind power plants with integrated CAES cannot offer minute reserve by operating the compressor, as it is directly (mechanically) propelled by the wind power plant and not connected to the grid. Hence these plants have the following options to participate in the minute reserve market: (1) during turbine operation, negative minute reserve can be offered by reducing the power of the turbine, and (2) if the turbine stands still, positive minute reserve can be provided by keeping the turbine in stand-by mode. The two-part tariff scheme for minute reserve is composed of a demand charge (for the readiness to provide minute reserve for the entire duration of the contract) and an energy rate (for the actual amount of electricity provided if the minute reserve is really called).

2. Model description

The CAES model developed in this paper is used to analyze three different systems: First, an assessment is made for a conventional onshore wind park with 100 MW of installed capacity without storage, located at the German North Sea coast where saline resources are frequent and thus saline caverns feasible (Base Case). Second, we study a combination of the wind park from the Base Case with a centralized CAES plant with 90 MW of compressor power and 180 MW of generator power; the compressed air is stored in a saline cavern and the CAES plant used independently of the wind power park to maximize profit (Variant 1). Third, we study a decentralized, integrated system where the wind turbines are used to directly compress air that is stored again in a saline cavern for later peak power generation (Variant 2). Note that each design requires different optimal operating strategies, modeled and detailed in the following subsections.

2.1. Base Case: Wind power plant without CAES

In the following, we consider the revenues of the wind park independently of the guaranteed feed-in tariff provided. The hourly electrical energy supplied by the wind park, $P_{\mathrm{Wind}}(\tau)$, is valued by the actual spot market price, $p_{\mathrm{SM}}(\tau)$, yielding annual revenues R_t:

$$R_t = \sum_{\tau=1}^{8760} \left(P_{\mathrm{Wind}}(\tau) \cdot p_{\mathrm{SM}}(\tau) \right). \tag{1}$$

From the annual revenues R_t, the initial investment I_0, the yearly costs C_t, and the price escalation factor r, we obtain the net present value

$$NPV_0 = -I_0 + \sum_{t=1}^{T} \frac{(R_t - C_t) \cdot r^{t-1}}{(1+i)^t} , \tag{2}$$

where i is the discount rate. For the calculation of nominal power generation costs the net expenditure stream is transformed into annual average payments (annuities), AN, using the annuity factor

$$a(i,T) = \frac{i \cdot (1+i)^T}{(1+i)^T - 1} , \tag{3}$$

yielding

$$AN = a(i,T)\cdot\left(-I_0-\sum_{t=1}^{T}\frac{C_t\cdot r^{t-1}}{(1+i)^t}\right), \tag{4}$$

The annuity is divided by the cumulated annual power production level, which gives the average power generation cost, $c_{G,t}$, in nominal terms

$$c_{\mathrm{G},t}=\frac{-AN}{\sum_{\tau=1}^{8760}P_{\mathrm{Wind}}(\tau)}\ . \tag{5}$$

Note that the power generation costs in real terms diminish over time, whereas the nominal ones remain constant. Still, we compute the nominal power generation costs because the guaranteed feed-in tariff paid on the basis of the German Renewable Energies Act 2007 (Deutscher Bundestag, 2007) is also in nominal terms (per kWh), with no price escalation clauses foreseen during the subsidization period. The amortization gives the time period from the initial investment until the expenses are fully paid back by the project revenues. The accumulated value of the project in period j, K_j, is given by

$$K_j=-I_0\cdot(1+i)^j+\sum_{t=1}^{j}(R_t-C_t)\cdot r^{t-1}\cdot(1+i)^{t-j}\ . \tag{6}$$

2.2. Variant 1: Wind power plant with central, independent CAES plant

The operating plan of a CAES power plant is based on the relationship between compressor and turbine operating time, which is given by the (energetic) filling level of the storage facility. The filling level at the end of the optimization period, E_T, results from the initial filling level, E_0, the energy fed into the grid, E_{in}, and the energy extracted from the storage facility, E_{out}, i.e.

$$E_T=E_0+E_{\mathrm{in}}-E_{\mathrm{out}}=E_0+P_{\mathrm{Com}}\cdot t_{\mathrm{Com}}\cdot\eta_{\mathrm{Com}}-\frac{P_{\mathrm{Tur}}\cdot t_{\mathrm{Tur}}}{\eta_{\mathrm{Tur}}}, \tag{7}$$

Where P_{Com} (P_{Tur}) denotes the electrical power of the compressor (turbine), t_{Com} (t_{Tur}) the cumulative operating time of the compressor (turbine) during the optimization period, η_{Com} (η_{Tur}) the efficiency of the compressor (turbine). The energy fed into and extracted from the CAES, respectively, results from the product of capacity and summed operating times of turbine and compressor and the corresponding energy conversion efficiencies, η_{Tur} and η_{Com}. Given the assumption that the filling level at the beginning and the end of the observation period is the same, we get the relationship between the turbine and compressor operation time as:

$$t_{\text{Tur}} = \frac{\eta_{\text{Tur}}}{P_{\text{Tur}}}\left(E_0 - E_{\text{in}} + P_{\text{Com}} \cdot t_{\text{Com}} \cdot \eta_{\text{Com}}\right). \tag{8}$$

However, the upper limit of the compressor operation time over the optimization period T, $t_{\text{Com,max}} = T - t_{\text{Tur}}$, is not the profit-maximizing operating time. Since total conversion efficiency, η_{CAES}, i.e. the product of turbine and compressor efficiency, implies that of each MWh electricity used only η_{CAES} MWh of electricity can be generated (and that additional variable costs occur), the spot market offer price must be higher than the purchase price inflated by $1/\eta_{\text{CAES}}$ plus variable cost. If the spot market price that can be achieved is below this level, then the CAES plant should be deactivated. Figure 1 illustrates this decision rule for spot market prices sorted in ascending order for one week.

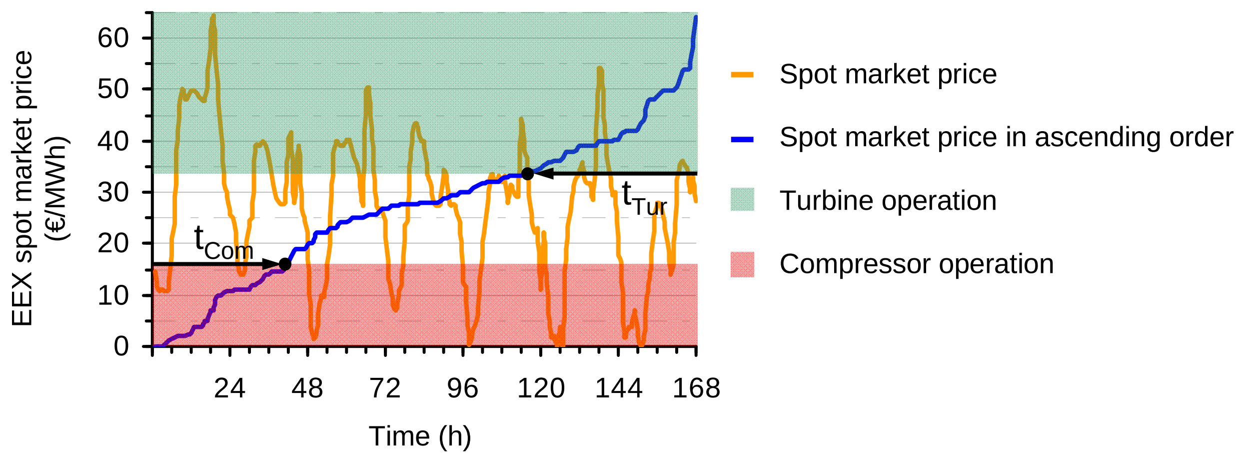


Figure 1. Time intervals for turbine and compressor operation depending on the spot market price

The yearly payment stream Z_t of the periodic revenues (R_t) and costs (C_t) is thus given by

$$Z_t = R_t - C_t = R_{\text{SM}} + R_{\text{RM}} - c_{\text{SM}} - c_{\text{var}} - c_{\text{fix}}\,, \tag{9}$$

where c_{SM} is the cost of buying electricity at the spot market to fill the cavern, c_{var} the variable costs, and c_{fix} the fixed costs of operating the CAES system.

The revenue from the spot market over the operating hours of the turbine in discrete form, R_{SM}, is given by the sum of the products of the turbine capacity (electrical power), P_{Tur}, and the electricity spot market price, $p_{\text{SM}}(\tau)$:

$$R_{\mathrm{SM}} = \sum_{\tau=1}^{t_{\mathrm{Tur}}} \left(P_{\mathrm{Tur}} \cdot p_{\mathrm{SM}}(\tau) \right). \tag{10}$$

Given the assumption that the minute reserve offered can always be contracted successfully in the market, the revenue from the provision of minute reserve on the basis of the hourly prices on the balancing market is given as:

$$\begin{aligned} R_{\mathrm{RM}} = & \sum_{\tau_{\mathrm{Tur}}=1}^{t_{\mathrm{Tur}}} \left[P_{\mathrm{Tur}} \cdot p_{\mathrm{RM,neg}}(\tau_{\mathrm{Tur}}) \right] + \sum_{\tau_{\mathrm{Com}}=1}^{t_{\mathrm{Com}}} \left[P_{\mathrm{Com}} \cdot p_{\mathrm{RM,pos}}(\tau_{\mathrm{Com}}) \right] \\ & + \sum_{\tau_{\mathrm{Comb}}=1}^{T-t_{\mathrm{Com}}-t_{\mathrm{Tur}}} \left(P_{\mathrm{Tur}} \cdot p_{\mathrm{RM,neg}}(\tau_{\mathrm{Comb}}) + P_{\mathrm{Com}} \cdot p_{\mathrm{RM,pos}}(\tau_{\mathrm{Comb}}) \right) \end{aligned} \tag{11}$$

where $p_{\mathrm{RM,neg}}$ ($p_{\mathrm{RM,pos}}$) is the price for negative (positive) minute reserve in the balancing market. In the following, we neglect the energy rate, as only a small fraction of the minute reserve is called up and the additional revenues are minor. For instance, in January and May 2007, only 0.1% and 0.04% of the positive minute reserve were called up. The energy rate in 2007 for positive minute reserve was on average 7.5 times higher than the spot market price, so that the additional revenues during the provision of positive minute reserve were less than 0.75% of the spot market revenues. In terms of negative minute reserve, 3.7% and 0.6% were called up, and the energy rate was only 3% of the spot market price. Hence the mistake of omitting the energy rate is less than 1% of the spot market revenues. Overall, the payment stream for the CAES power plant is given by

$$Z_t = R_{\mathrm{SM}} + R_{\mathrm{RM}} - \sum_{\tau=1}^{t_{\mathrm{Com}}} \left(P_{\mathrm{Com}} \cdot p_{\mathrm{SM}}(\tau) \right) - t_{\mathrm{Tur}} \cdot P_{\mathrm{Tur}} \cdot c_{\mathrm{var}} - P_{\mathrm{Tur}} \cdot c_{\mathrm{fix}} \tag{12}$$

For maximizing the discrete payment series the turbine and generator operating times are calculated with an algorithm programmed in Excel/VisualBasic for the given optimality criterion. The compressor and turbine operating times are then determined based on the maximum economic surplus. From the ascending spot market price curve we can derive the maximum price at which the *compressor* can still be operated, $p_{\mathrm{SM,Com,max}}$, and the lowest price at which the turbine can be run, $p_{\mathrm{SM,Tur,max}}$ (Figure 2).

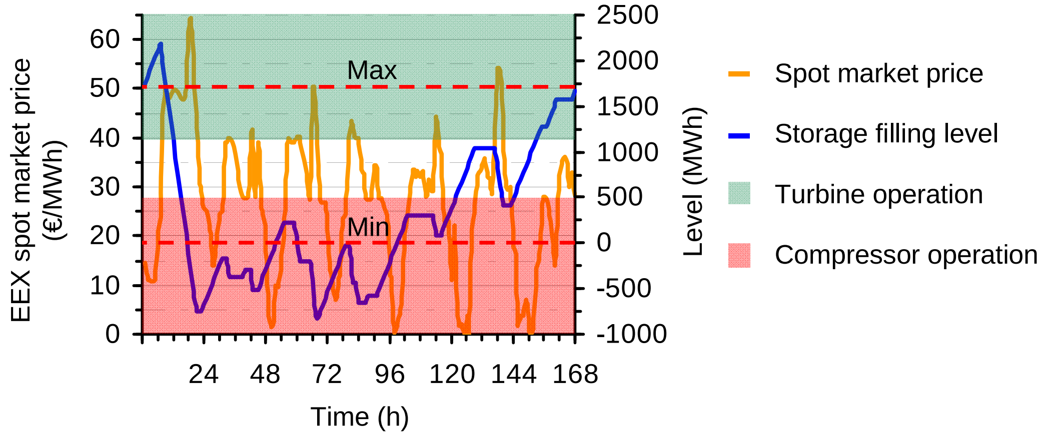


Figure 2. Filling level of the CAES system for operation optimization w/o consideration of storage limit

Note that for this optimization, for the time being the boundary conditions for the filling level are not taken into account yet, so that negative filling levels and filling levels beyond the maximum could occur (Figure 2). In these cases an overarching three-stage recursive optimization algorithm is used with two distinct time intervals investigated:

- **B1:** Optimization over the entire observation period [t_0, T] without consideration of the filling level boundaries. The energetic filling levels of the storage system at the beginning and the end of the optimization period are defined as $E_0 = E_T = E_{\max}$.
- **B2:** Check whether the filling level boundaries are surpassed. If this is the case, a third step B3 is executed.
- **B3:** The observation period is split into two time intervals and the algorithm executed first for interval [t_0, t_1], starting with step B1, where T_1 is the point in time where the filling level reaches its highest or lowest value. After that t_0 is set equal to t_1 and the algorithm, starting again with step B1, is executed for the interval [t_1, T]. If the optimization period is divided because of an undercutting of the minimal filling level, the filling level is set to zero as a constraint at the division line. Vice versa, in case of surpassing the maximum filling level, it is set as an additional constraint. The result of applying this recursive algorithm is shown in Figure 3.

The result of our optimization is a profit-maximizing payment stream. Whereas for an analytically determined electricity price an analytical optimization would be possible, the discrete price data points make such a two-stage recursive algorithm necessary (cf. Lu et al., 2004, p.837).

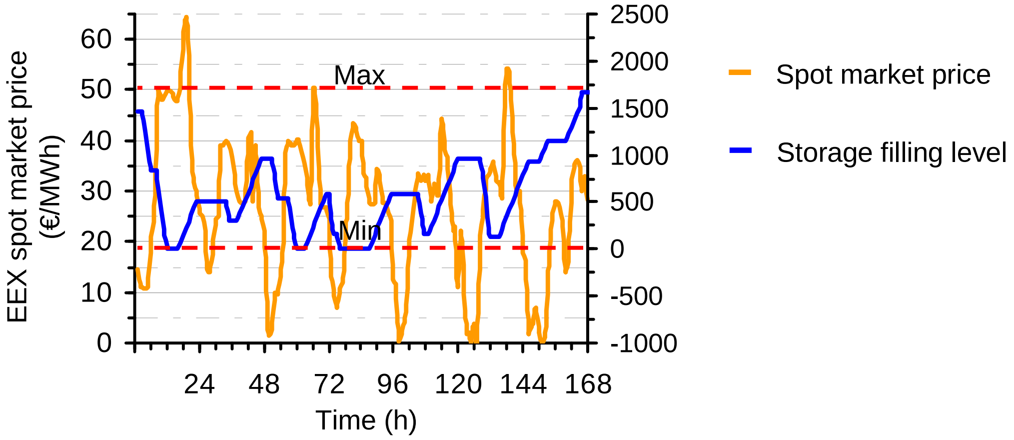


Figure 3. Filling level of the CAES system for operation optimization with consideration of storage limits

From the profit-maximizing payment stream Z_{TN} we obtain the NPV again by considering a uniform annual price escalation factor r analogously to (1). Since the lifetime of a CAES power plant is longer than the observation period, however, the residual value (RV) of the storage power plant has to be taken into account as well. To this end, we consider the initial investment as an NPV of a price-dynamic stream of payments over time TN as:

$$I_0 = \sum_{t=1}^{TN} \frac{Z_{TN} \cdot r^{t-1}}{(1+i)^t} \tag{13}$$

This payment stream is split into two partial time series,

$$RV_{0,T} = \sum_{t=1}^{T} \frac{Z_{TN} \cdot r^{t-1}}{(1+i)^t}; \qquad PV_{0,T} = \sum_{t=T}^{TN} \frac{Z_{TN} \cdot r^{t-1}}{(1+i)^t}; \tag{14}$$

where the residual value $RV_{0,T}$ represents the present value of all payments from 0 until T and $PV_{0,T}$ the present value of the residual value, and Z_{TN} is the profit-maximizing payment stream (i.e. the net revenues for the case of optimal turbine operation). $RV_{0,T}$, therefore, is the modified investment value, adjusted for the observation period used in the calculation. This yields a net present value

$$NPV_0 = -I_{0,T} + \sum_{t=1}^{T} \frac{(R_t - C_t) \cdot r^{t-1}}{(1+i)^t} \tag{15}$$

from operating the CAES plant and supplying energy to the spot market. As the return on investment (RoI) is computed by a static approximation procedure, the residual value, RV, is given by the linear depreciation. If T is the observation period for the profitability calculation and T_L the technical lifetime of the investment good, the residual value RV can be computed as

$$RV = I_0 \cdot \left(1 - \frac{T}{T_L}\right) . \tag{16}$$

2.3. Variant 2: Wind park with integrated, decentral CAES system

Since in Variant 2 wind power is converted without energy conversion in the generator, this option, *ceteris paribus*, yields a higher overall conversion efficiency (in our case 95%, so that a total capacity of 95 MW is available at the compressor). However, since the compressed air is transported over longer distances from the wind power plant to the storage cavern, compared to a centralized CAES power plant, additional flow losses occur, which we assume to amount to 5%. Otherwise, we use the same parameter values as for the centralized CAES power plant.

The operating strategy for such a decentralized, integrated system is very different to that of a centralized CAES plant, because the CAES is filled according to wind conditions, and not depending on the spot market price. Hence optimization is based on revenue maximization, according to an algorithm derived from Variant 1. Specifically, for the 1-week optimization period T used for describing our model, total energy fed into the CAES over a year is given by adding up wind power feed-in, P_{Wind}, adjusted for compressor efficiency η_{Com}:

$$E_{\mathrm{in}} = \sum_{\tau=1}^{T} P_{\mathrm{Wind}}\left(\tau\right) \cdot \eta_{\mathrm{Com}} . \tag{17}$$

Depending on the predetermined energetic filling level of the storage facility at the beginning, E_0, and at the end of the observation period, E_T, the operating time of the turbine, t_{T}, is calculated as:

$$t_{\mathrm{Tur}} = \frac{\eta_{\mathrm{Tur}}}{P_{\mathrm{Tur}}}\left(E_0 - E_{\mathrm{T}} + E_{\mathrm{in}}\right). \tag{18}$$

Based on the ordered revenues from the spot market and the reserve market, and accounting for opportunity costs, the minimal spot market price, $p_{\mathrm{SM,min},T}$, can be computed for a given t_{Tur}, above which turbine operation yields the maximum possible revenue (Figure 4).

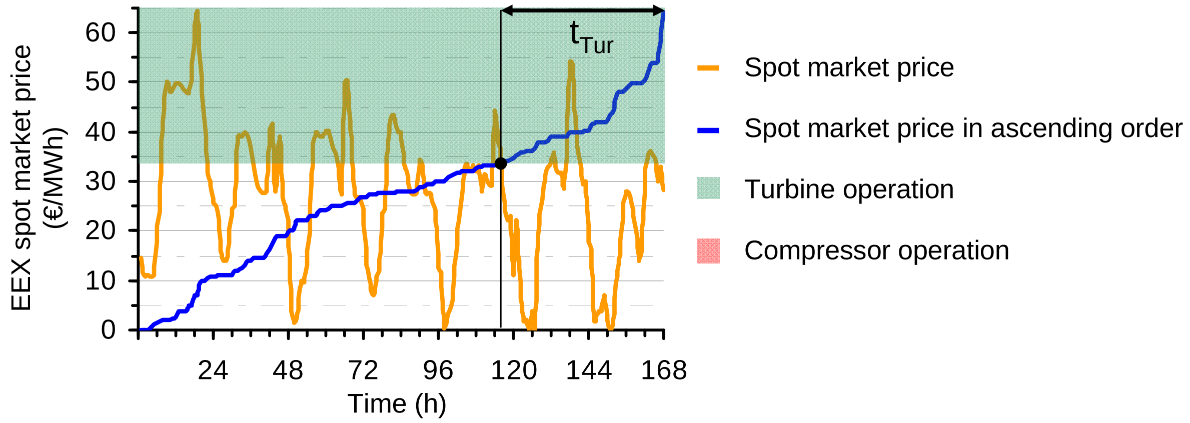


Figure 4. Determination of the minimum spot market price for turbine operation and turbine operating time during the observation period

The minimum price for turbine operation is then used to determine the operating times of the turbine over the observation period. These are the hours during which the market price exceeds $p_{min,T}$ (upper part in Figure 4, marked green), so that the filling level over time, E_t, is determined by

$$E(t) = E_0 + \sum_{\tau=1}^{t} \left[E_{\text{in}}(\tau) - E_{\text{out}}(\tau) \right]. \tag{19}$$

Note that an additional condition for determining the operating times of the turbine is that the spot market price must be higher than the variable cost of the process, i.e. $p_{\text{sm}} > c_{\text{var}}$.

The payment stream for this variant is calculated for the entire plant, comprising the wind power plant with integrated air pressurization and the CAES plant without compressor. After the initial investment I_0 the periodic payments are composed of the annual fixed costs, c_{fix}, the fuel cost of natural gas for operating the turbine of the diabatic CAES plant, c_{gas}, and other variable costs of the process, $c_{\text{var,o}}$. The incoming payments are mainly from the revenues from selling electricity from the CAES plant at the spot market, R_{SM}, and those from minute reserve market contracts, R_{RM}. The overall payment stream is thus given by $Z_t = R_{\text{SM}} + R_{\text{RM}} - c_{\text{var,o}} - c_{\text{var}} - c_{\text{fix}}$.

In the reserve market, in contrast to the centralized CAES plant, this plant can offer positive reserve by reducing compressor power, as it does not need electricity from the grid for air compression. Moreover, since the turbine is operated independently from the compressor, negative (positive) minute reserve can be offered during turbine operation (standstill) up to turbine capacity. Assuming that the minute reserve offered can always be sold successfully in the bidding process and that additional revenues from calling reserve power are negligible, the revenues R_{RM} based on hourly prices in the reserve power market amount to

$$R_{\mathrm{RM}} = \sum_{\tau_{\mathrm{Tur}}=1}^{t_{\mathrm{Tur}}} \left[P_{\mathrm{Tur}} \cdot p_{\mathrm{RM,neg}}\left(\tau_{\mathrm{Tur}}\right)\right] + \sum_{\tau_{\cancel{\mathrm{Tur}}}=1}^{T-t_{\mathrm{Tur}}} \left[P_{\mathrm{Tur}} \cdot p_{\mathrm{RM,pos}}\left(\tau_{\cancel{\mathrm{Tur}}}\right)\right], \tag{20}$$

with $p_{\mathrm{RM,neg}}$ ($p_{\mathrm{RM,pos}}$) the price of balancing energy market for negative (positive) minute reserve and ~~Tur~~ the time when the turbine is not running. The total payment stream, Z, is thus given by:

$$Z = R_{\mathrm{SM}} + R_{\mathrm{RM}} - t_{\mathrm{Tur}} P_{\mathrm{Tur}} c_{\mathrm{var}} - P_{\mathrm{Tur}} \cdot c_{\mathrm{fix}} \,. \tag{21}$$

Note that also in this case the boundary conditions of the filling level are ignored. Analogously to Variant 1, we apply the same recursive optimization algorithm for dividing the optimization period as before. With the revenue-maximizing payment stream we can then determine the present value, power generation costs and amortization times, given the replacement value of the initial investment. The RoI is again calculated with the static residual value given linear depreciation.

3. The Data

Table 1 provides an overview of the data used for our analysis, which were compiled from a number of different sources (for details see Latz, 2008).

Table 1. Specific costs of the wind power plant (WPP), combined with a centralized CAES (Variant 1) or an integrated, decentral CAES (Variant 2)

			Base Case	Variant 1		Variant 2			
Position	Symbol	Unit	WPP	CAES diabatic	CAES adiabatic	WPP diab.	CAES diab.	WPP adiab.	CAES adiab.
Capital cost									
Main investment cost	I_0	€/kW	1142	356.4	451.8	1149	244.4	1339.8	244.4
Turbine		€/kW		244.4	244.4		244.4		244.4
Compressor		€/kW		224.0	414.8		-		-
Saline aquifer stor.		€/kWh		2.0	2.0		2.0		2.0
Other investment cost	$I_{0,\mathrm{OC}}$	€/kW	320	238.8	334.2	205	203.0	205	284.1
Operating cost									
Fixed	c_{fix}	€/kWa	36/54[a)]	9.0	10.0	36/54[a)]	6.0		6.7
Variable	c_{var}	€/kWh	-	0.0323	0.003		0.0313		0.002

[a)] 36 €/kWa during years 1–10, 54 €/kWa during years 11–20.

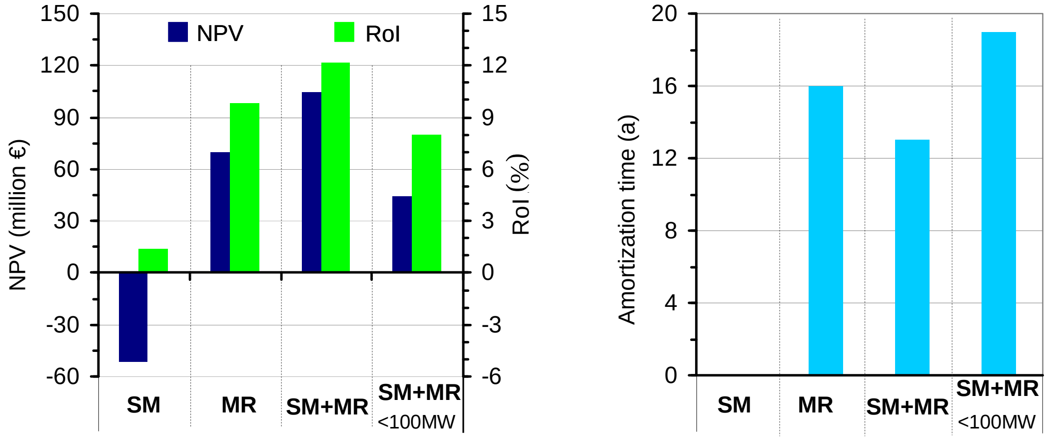
4. Results

4.1. Impact of market conditions on minute reserve

As already mentioned in the introduction, in the current German electricity market for minute reserve six blocks with a duration of four hours each are traded. Hence the potential of CAES power plants with storage capability of six hours is strongly restricted, since the flexibility to follow hourly market fluctuations is ruled out by binding to the contracts for balancing energy. Consequently, we have studied three different scenarios: (1) the CAES power plant is used for spot market trading; (2) the CAES power plant is used for the provision of minute reserve; and (3) there exists a free market for minute reserve where hourly contracts can be traded analogously to the spot market.[1]

Figure 5 shows the net present value (NPV), RoI and payback period for the three different scenarios, assuming a 30 years' lifetime of the CAES power plant. Since we only consider the storage function of the CAES plant, computation of unit generation costs is not needed. We can see that spot market trading only is not economical (NPV of €-51.2 million, RoI of 1.4%), while trading exclusively on the minute reserve market yields a positive NPV of €69.6 million, an RoI of 9.8%, and an amortization time of 16 years. Note that the power plant in this scenario does not lead to a smoothing of fluctuations from the feed-in of wind power to the grid. Finally, the combined trading on the spot and minute reserve market is economically the most attractive one: the NPV amounts to €104.4 million and the RoI is 12.2%. Also interesting is the finding that constraining the maximum hourly contracts on the minute reserve market to 100 MW reduces the NPV by 57%. A more flexible contracting scheme, such as hourly contracts (like on the spot market) instead of 4-hour contracts, are effective ways to make CAES significantly more economical.

[1] Note that *de facto* there is no upper limit for the power that can be offered, as in 2007 it was common to trade minute reserve blocks of up to 200 MW. Note further that the scenario considered by Gatzen (2008) is a free market for minute reserve based on hourly contracts, with the only limitation that an individual plant is only allowed to trade a minute reserve capacity of up to 100 MW.



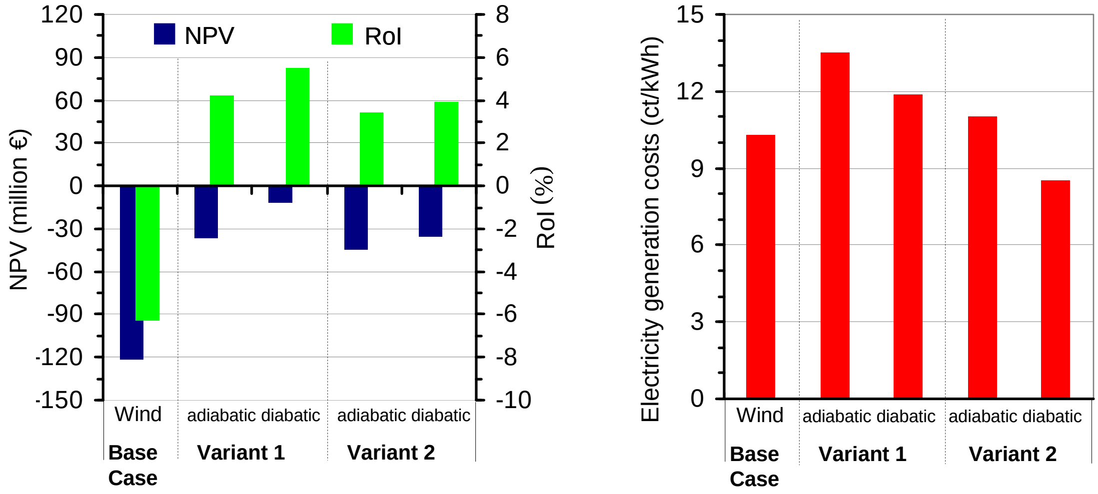
(a) NPV and ROI (b) Amortization time

Figure 5. Comparison of utilization of an adiabatic centralized CAES power plant

Notation: SM = exclusive trading on the spot market; MR = exclusive trading on the minute reserve market; SM+MR = combined trading on the spot and minute reserve market; SM+MR < 100 MW = combined trading on the spot and minute reserve market with a bidding limit for minute reserve of 100 MW per plant

4.2. Comparison of the variants studied

Figure 6 shows that all variants considered yield negative NPVs, the wind park without CAES featuring the lowest value. Hence we can conclude that storage is economically beneficial in all cases. We also find that the diabatic process is more advantageous in terms of the NPV created than the adiabatic alternative in both CAES variants investigated.



(a) NPV and RoI (b) Power generation cost

Figure 6. Comparison of the variants (without consideration of EEG subsidies)

Notation: Base Case = Wind park (w/o CAES); Variant 1 = Combination wind park with centralized CAES (diabatic, adiabatic); Variant 2 = Wind park with integrated CAES and decentralized storage (diabatic, adiabatic)

Variant 2, i.e. the integrated, decentralized CAES, turns out to be less attractive than centralized CAES: the NPV for Variant 1 is €-36.6 million (adiabatic) and €-11.6 million (diabatic), respectively, whereas it is €-45.1 million and €-36.0 million for Variant 2. In other words, the reduced investment costs due to the CAES integration is overcompensated by the lower revenues gained due to lower operating flexibility. The lower flexibility accrues from the fact that the compressor of the integrated system cannot be used to provide balancing energy, and that at times of high wind speeds and high spot market prices there is no possibility to directly (i.e. w/o storage) feed the generated electricity into the grid.

The RoI for the base case (wind park w/o CAES) is €-6.3%, whereas it is 3.4% for Variant 1 and 5.5% for Variant 2, respectively. This, however, is still lower than the discount rate of 7.5%. And even though NPV and RoI of the CAES options considered are higher than for the Base Case, the storage options often lead to higher power generation costs. Note that since storage power plants are flexible with respect to the timing of feeding the electricity into the grid (within the boundaries of the technical option considered), they can reap higher revenues. Hence the generation costs only help to determine the minimum average spot market price during the feed-in that has to be achieved in order to yield a positive NPV.

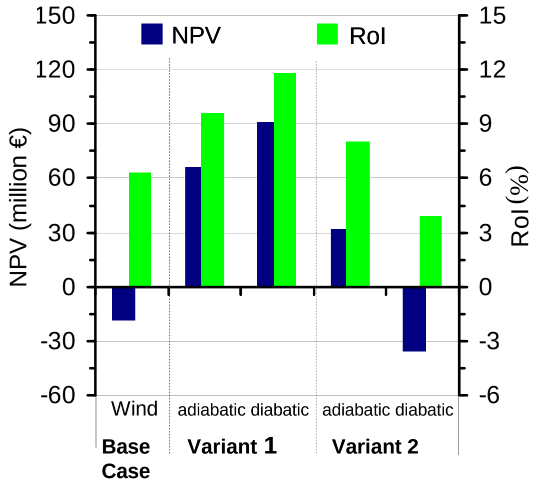
The differences in the generation costs show the relative economic advantage of the various options. In this respect Variant 1 is more attractive than Variant 2, since for Variant 1 a higher share of the revenues is gained by means of balancing energy and a lower share on the spot market, enabling the feed-in at peak-load times. For example, at the optimum the turbine of a centralized, adiabatic CAES power plant is operated 457 hrs/a, whereas the turbine of a wind park with integrated adiabatic CAES is run 698 hrs/a. We can conclude from this that power plants with integrated CAES make a more substantial contribution to smoothen wind energy fluctuations, whereas centralized CAES power plants provide a larger share of balancing energy.

If subsidization according to the German Renewables Energy Act (EEG, 2007) is considered, the following changes occur:

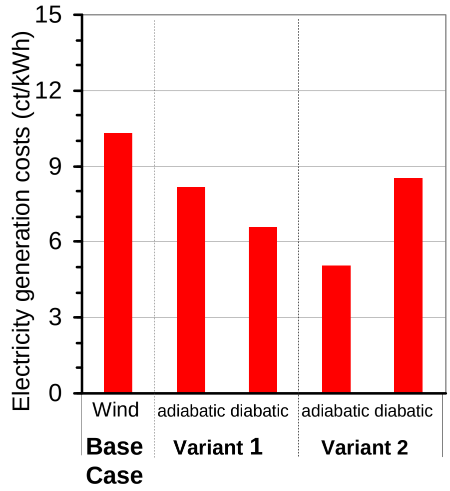
- In the Base Case, the operator receives a guaranteed feed-in tariff of 7.55 ct/kWh for the first eleven years, and thereafter (i.e. for another nine years) 4.77 ct/kWh;

- For Variant 1, the operator of the wind park receives the same feed-in tariff as for the Base Case (i.e. the independently operated storage power plant is not affected);
- For Variant 2, the wind power is not fed into the grid but stored as compressed air. The EEG foresees that for renewable electricity, even if it is stored in between, the same feed-in tariff is granted as for the Base Case (cf. Dietrich et al., 2008), so that for the adiabatic version an EEG subsidy is granted. However, since the flexible operation of a CAES power plant allows gaining higher revenues on the spot market than the feed-in tariffs granted, this is unattractive, and for Variant 2 no advantage arises. Only a mark-up on the spot market price could compensate for the disadvantage of Variant 2 compared to Variant 1. In the following, we assume a mark-up for the feed-in of 4.84 ct/kWh for Variant 2, which is the average subsidy rate paid in 2007 compared to the spot market price, whereas this does not apply for Variant 1, where the energy fed into the grid is not only from renewables.

Figure 7 depicts the results from the calculations when the EEG mark-up is included. It can be seen that all variants with a storage option are economically viable. Variant 1 in the diabatic version still yields the highest NPV of €91.2 million and an RoI of 11.8%. Even the adiabatic version of Variant 1 is more profitable than the adiabatic version of Variant 2, although it is used much less for smoothing wind power fluctuations than for providing balancing energy. Since subsidization of the diabatic version of Variant 2 is unlikely, this plant is economically not attractive and thus irrelevant. For the Base Case the RoI is 6.3%. For the variants with storage facility it takes positive values at 3.4% and 5.5%, but is lower than the discount rate of 7.5%. And although the NPV and RoI for the variants with storage facility are higher than for the Base Case, sometimes higher power generation cost can occur, which is an interesting finding and may seem counterintuitive. However, it is not a criterion for judging the merits of the investment, since the storage plant can influence the timing of the electricity feed-in (subject to the prevailing technical boundaries) and thus can gain higher revenues. The power generation cost show only which average spot market price during the feed-in has to be reached at a minimum in order to achieve a positive NPV.



(a) NPV and RoI



(b) Power generation cost

Figure 7. Comparison of the variants (considering a mark-up)

Notes: Base Case = Wind park (w/o CAES); Variant 1 = Combination wind park with centralized CAES (diabatic, adiabatic); Variant 2 = Wind park with integrated CAES and decentralized storage (diabatic, adiabatic)

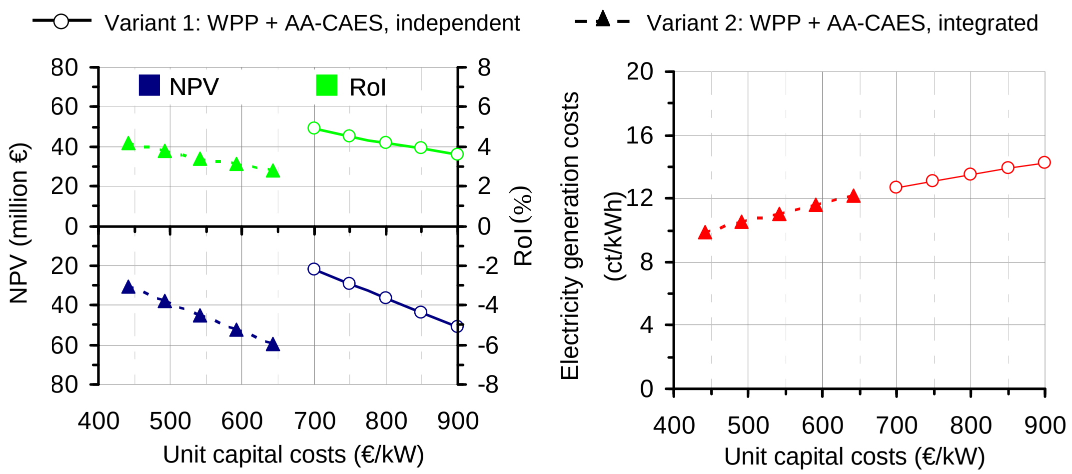
4.3. Sensitivity analysis

Since worldwide only three diabatic (and no adiabatic) CAES power plants have been built so far, economic uncertainties are still relatively high, and it makes sense to perform a sensitivity analysis. In this section, we report on the sensitivity analysis done for the adiabatic versions of Variant 1 and Variant 2. Note that the diabatic version of the integrated CAES is not considered, because it is not economically feasible without EEG subsidies. Also, gas-fired power plants for smoothing wind power feed-in foils the goal of reducing CO_2 emissions. Finally, Gatzen (2008) has shown that the amplitude of the fluctuations in the electricity price will decrease in the future. Further, due to the higher energy efficiency adiabatic CAES power plants will be more profitable than diabatic ones (cf. Gatzen, 2008, p.155f).

The specific capital costs for adiabatic CAES power plants found in the literature lie between 700-900 €/kW, so that for our reference calculations we use an average value of 800 €/kW. For Variant 2 the unit capital costs for the CAES components are calculated at 542 €/kW. Starting from these values, we varied them by +/-100 €/kW. The results are presented in Figure 8 (for both wind park and CAES). As can be seen, the linear decrease in the NPV for an increase in the unit capital cost of 100 €/kW is €14.58 million in both variants. Since the

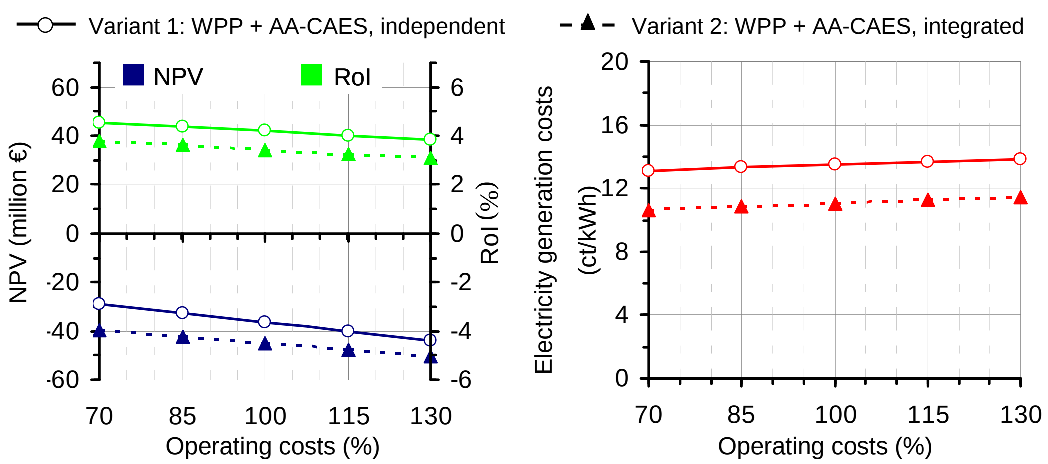
NPV is negative in all cases, uncertainty in the capital cost is not relevant for the economic viability. Note that, despite the fact that investment costs for Variant 2 at 542 €/kW are 258 €/kW lower than for Variant 1, Variant 2 has the lower NPV. In order to make Variant 2 more attractive than Variant 1, the cost reduction for Variant 2 must be at least 316 €/kW. Over the interval studied the RoI for Variant 1 is between 3.6-4.9%, whereas for Variant 2 it is between 2.8-4.2%.

Next, we have varied the (fixed and variable) operating costs of the CAES components by +/- 30%. As can be seen from Figure 9, the operating costs have a different impact on the two variants. For Variant 1 the NPV is affected by €7.5 million, for Variant 2 by €5.4 million. For the operating cost range studied, the NPV does not reach positive values for any variant.



(a) NPV and RoI (b) Power generation cost

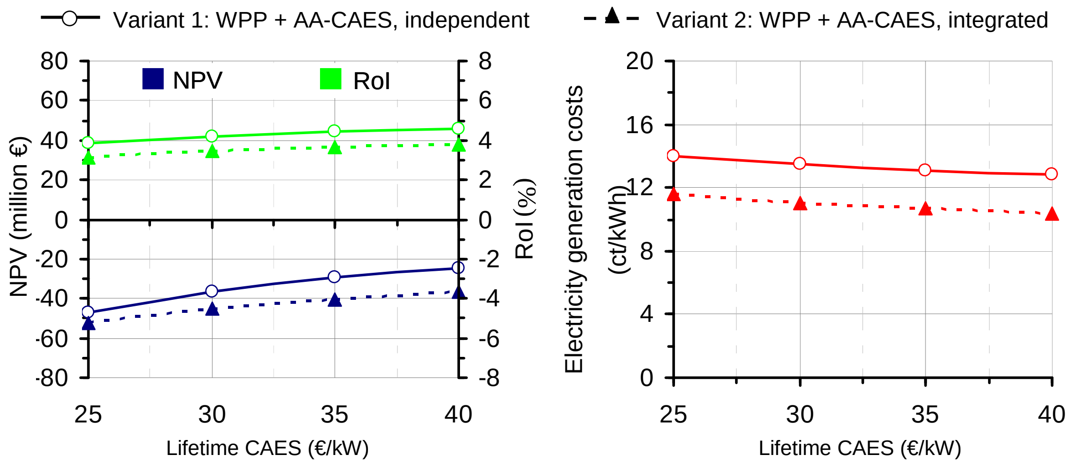
Figure 8. Sensitivity analysis for the specific capital costs



(a) NPV and RoI (b) Power generation cost

Figure 9. Sensitivity analysis for the operating costs

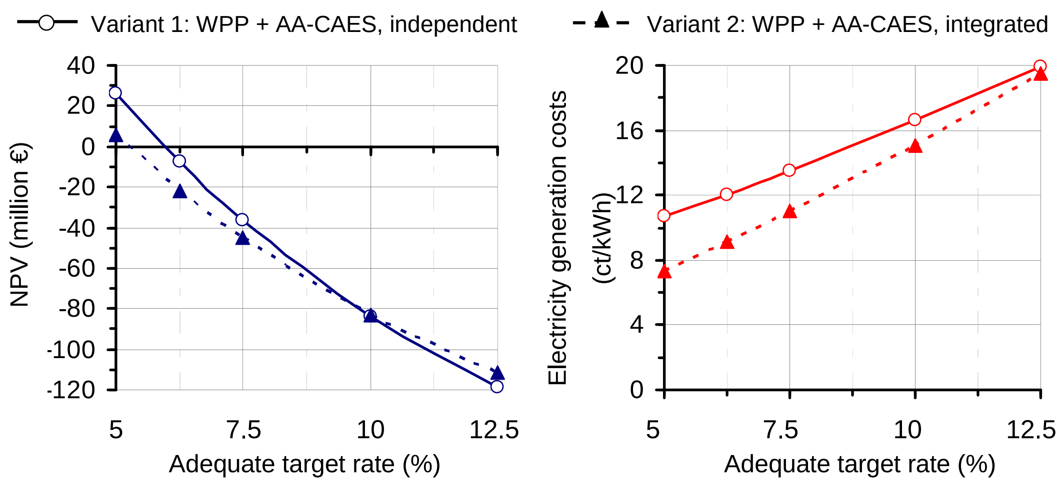
Furthermore, we have studied the sensitivity with regard to the lifetime of the CAES plant, which in the literature is commonly assumed to be between 30-40 years. The diabatic CAES power plant in Huntorf, Germany, has been in operation for 30 years. The lifetime of the wind power plant is assumed to be 20 years. As can be seen from the results provided in Figure 10, lifetime has a positive but declining impact on the NPV.



(a) NPV and RoI (b) Power generation cost

Figure 10. Sensitivity analysis for the CAES lifetime

Finally, we have looked at the sensitivity of the NPV with respect to the discount rate. As can be seen from Figure 11, the discount rate has a strong impact on the NPV. The critical value, where the NPV is zero, is at 6.0% for Variant 1 and at 5.25% for Variant 2. At the standard discount rate of 7.5% (e.g. Deutscher Bundestag, 2007, pp.75,113) the NPV for Variant 1 is at €-36.65 million and at €-45.11 million for Variant 2. At a discount rate of 12.5% the NPV is as low as €-118.8 million (Variant 1) and €-111.2 million (Variant 2). Interestingly, whereas Variant 2 at a discount rate of less than 9.9% achieves a lower NPV than Variant 1, the opposite is true for higher discount rates. In other words, at higher discount rates the wind power plant with integrated, decentralized CAES is economically more attractive than a centralized CAES power plant. Note that we do not report the RoI here as it is not affected by variations in the discount rate.



(a) NPV and RoI (b) Power generation cost

Figure 11. Sensitivity analysis for the discount rate

5. Discussion

The massive expansion of wind energy use and the resulting increased fluctuation of a larger share of power generation require measures for a better capacity utilization of the grid. One solution is the expansion of storage facilities in the grid. Apart from pump-storage hydro power systems, which often have limited untapped potentials (at least in Germany), CAES systems are one of the few alternative commercial large-scale options that exist today.

Whereas diabatic CAES, which requires additional gas-firing of the turbine, is technically mature, adiabatic CAES are currently under development that do not need any gas-firing. A further promising alternative are wind power plants with integrated, decentralized CAES. Instead of being equipped with generators for power production, the wind power plants are equipped with compressors for air pressurization that can then be stored decentrally.

In our study we investigated and compared the economics of different variants of such CAES systems. We find that while studies comparing conventional diabatic with adiabatic CAES systems and other storage systems exist, the concept of wind power plants with integrated CAES has not been scrutinized so far. For the analysis we developed an economic model that allows us to study three different variants of systems: (1) a conventional wind park without CAES; (2) a wind park with conventional centralized CAES in diabatic or adiabatic use; and (3) a wind park with integrated CAES in diabatic or adiabatic use.

We have compiled capital and O&M costs for each of these variants from the literature. Using real data on the feed-in of wind power to the grid, spot market prices, and the price of minute reserve for the year 2007, we then developed an algorithm for profit-maximizing operation of the different variants. This yields the net revenue streams that allow for the calculation of the NPV, the RoI, the generation cost, and the payback period of the different systems.

6. Conclusions

The results show that the economics of the systems considered depend strongly on how intensively the spot market and market for minute reserve is used. Only when the combined trade in the spot market and minute market is enabled by a sufficiently flexible market, the CAES plant can be operated economically, and help to stabilize fluctuations from the large-scale feed-in of wind power. Unsurprisingly, without support from the EEG, all variants turn out to be uneconomical even if such flexible market conditions prevail. Compared to the wind park without storage system, however, all variants with CAES lead to a higher NPV, so that we can conclude that CAES is economically viable in all cases. A centralized CAES power is economically more attractive than a wind power plant with integrated CAES. Furthermore, diabatic CAES are more profitable than adiabatic systems, and the ecological disadvantage of natural gas use and related CO_2 emissions directly undermines the advantage of feeding in renewable wind power.

Whereas the feed-in of wind power from centralized CAES is remunerated according to EEG regulation, the EEG does not foresee any subsidization of wind power plants with integrated CAES, since the wind power is not directly fed into the grid and because the electricity price that can be achieved by the storage power plant is above the feed-in tariff according to the EEG.

We conclude that given the present conditions on the minute reserve market no CAES power plant is economically feasible. However, as soon as hourly contracts can be concluded on the minute reserve market, such as it is possible on the spot market, CAES becomes attractive for smoothing fluctuations caused by wind energy feed-in. The economically most attractive option today is a centralized diabatic CAES power plant, followed by the centralized adiabatic alternative. However, even if integrated, centralized CAES is promoted by means of feed-in tariff, centralized CAES power plants still remain economically more attractive.

Acknowledgement

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Glossary/Nomenclature

a) Abbreviations

AA	…	Advanced adiabatic
CAES	…	Compressed Air Energy Storage
EEG	…	Erneuerbare Energien Gesetz (Renewable Energies Act)
WPP	…	Wind power plant

b) Symbols

a	…	annuity factor
AN	…	annuity
C	…	cost (general)
c, c_{fix}, c_{var}, $c_{\mathrm{var,o}}$, c_{SM}, c_{gas}, c_{PG}, c_t	…	average cost (fixed, variable, other variable, spot market, natural gas, power generation, yearly)
E_0, E_{T}, E_{in}, E_{out}, $E_{\max}$	…	energy/filling level (beginning, end, feed-in, extraction, and maximum possible)
η_{C}, η_{T}, η_{CAES}	…	efficiency (compressor, turbine, total CAES system)
i	…	discount rate
I_0	…	initial investment
K	…	accumulated value of the project
NPV_0	…	net present value
RoI	…	return on investment
p_{SM}, $p_{\mathrm{SM,min}}$,		

$p_{\mathrm{SM,max}}$	…	spot market price (min./max.)
p_{RM}, $p_{\mathrm{RM,pos}}$, $p_{\mathrm{RM,neg}}$	…	minute reserve market price (pos./neg.)
P_{Wind}, P_{Tur}, P_{Com}	…	electrical power (wind, turbine, compressor)
r	…	price escalation factor
R, R_{SM}, R_{RM}	…	revenue (spot market, minute reserve market)
RV	…	residual value
T, T_L, TN	…	end of optimization period (modeling time horizon), plant lifetime, time horizon for profit-maximizing payment stream
Z, Z_{TN} , Z_t	…	payment stream (profit-maximizing, yearly)
c) Indices		
j	…	time (years)
t, t_{Com}, t_{Tur}	…	operating time (compressor, turbine) (duration in hours)
τ, τ_{Com}, τ_{Tur}, $\tau_{\cancel{\mathrm{Tur}}}$, τ_{Comb}	…	hourly time index (compressor, turbine, no turbine, combined turbine/compressor use)

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