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The operational economics of compressed air energy storage systems under uncertainty

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ABSTRACT

A Compressed Air Energy Storage System is a means of storing energy which can then be used when the demand for energy increases. In this system, air is compressed in a cavern when power prices are low, and this air is used to run a natural gas-fired turbine to generate power when prices go up, with the aim of profiting from the price difference. This type of system can independently compress air, generate electricity, or do both. However, the prices of electricity and natural gas fluctuate, which directly impacts the amount of revenue that can be made, and this requires the calculating of estimates to optimize operation strategies and maximize profit. For these reasons, this is a crucial energy storage technology that requires economic analyses to justify investment decisions in power markets. In this paper, a mixed integer programming method is developed to schedule the operation of the system for forward market prices that are estimated using a markov-based probabilistic model. Then an algorithm that includes two separate modules in a simulation is employed to optimize the annual operation of the system. The paper presents a case study for Turkey as well as economic analyses based on probabilistic forward prices and the profits obtained from the optimization module.

Contents

1. Introduction

Compressed Air Energy Storage (CAES) is an integrated system that is used to store potential energy during off-peak times which can then be used when energy is needed during peak times. The CAES system can be thought of as a modification to a Natural Gas Turbine (NGT) in which the generation turbine is connected to an air compressor. When natural gas is combusted in the turbine to generate electricity, the compressed air drives the combustion process. In such a system, the compressor usually consumes two-thirds of the electric power generated in the gas turbine and thus only one-third of the power output is actually transmitted to the power grid. The CAES system makes it possible to separate the combustion and compression processes, thus resulting in three times more power output in terms of energy input. Currently, there are two CAES plants in operation, one of which is the Huntorf Plant which began operations in 1978 as the world's first CAES [1]. The plant provides peak shaving, spinning reserves and support for the power market with a capacity of 290 MW. The total volume of the reservoir, which is composed of two underground salt caverns

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Notation

t	hour index in the year
n	year index
$G_{n,t}$	1 if the unit generates in hour t of year n, 0 otherwise
$P_{n,t}$	1 if the compressor runs in hour t of year n, 0 otherwise
$U^c_{n,t}$	1 if the compressor is started up in hour t of year n, 0 otherwise
$U^g_{n,t}$	1 if the generator is started up in hour t of year n, 0 otherwise
$I_{n,t}$	inventory of the compressed air in hour t of year n (generation hours)
$I_{n,f}$	inventory of the compressed air at the beginning of year n (generation rs)
$I_{n,l}$	inventory of the compressed air at the end of year n (generation hours)
Q_G	the capacity of the generating unit (MW)
Q_C	the capacity of the compressor (MW)
Q_{CT}	the capacity of the gas cycle turbine (MW)
$MP_{n,t}$	market price for power in hour t of year n ($/MWh)
$N_{n,t}$	the gas price in hour t of year n ($/mmBTU)
H_{CT}	the heat rate of the gas cycle turbine (mmBTU/MWh)
VOM^g_n	the variable operation maintenance cost for generator in year n ($/MWh)
VOM^C_n	the variable operation maintenance cost for compressor in year n ($/MWh)
S^c_n	start-up cost of the compressor in year n ($/start-up)
S^g_n	start-up cost of the generator in year n ($/start-up)
κ	the number of compression hours consumed by each generating hour
B	the number of generating hours possible for each compression hour
θ	the capacity of the facility in total compression hours
η_c	efficiency of the compressor
η_g	efficiency of generation turbine
$r(n)$	the change in power price in year n compared to year $n-1$ (%)
$s(n)$	the change in natural gas price in year n compared to year $n-1$ (%)
P_r	transition probability matrix for $r(n)$
A_n	DTMC states for power price changes
q_n	the steady state probabilities for annual change in power prices
$F_r()$	the cumulative distribution function of the percentage changes in power prices
$s(n)$	the change in natural gas price in year n compared to $n-1$ (%)
T_r	transition probability matrix for $s(n)$
B_n	DTMC states for natural gas price changes
v_n	the steady state probabilities for annual change in natural gas prices
$H_r()$	the cumulative distribution function of the percentage changes in natural gas prices
Rv_n	operation revenue of the CAES in year n (Objective function value)
y	number of replications in the multi-year analysis
f	discount rate for the forward revenues
CC_O	the total initial cost of CAES system ($)

located 2100–2600 feet below the surface, is 11 million cubic feet, and these hold up to 1000 psi of compressed air. The system fully recharges 12 h of off-peak power, and the system can run at full output capacity for up to 4 h. The other CAES plant is the McIntosh facility which was built in 1991 and is currently owned by the Alabama Electric Power Company. It is run from a cylindrical salt cavern, which at 300 m deep and 80 m wide contains a volume of 5.32 million m^3. The plant has a capacity of 110 MW and can supply power for 26 h with a start-up of 9–13 min. A typical CAES consists of a serial system that includes a compressor, storage, expander and generator, as illustrated in Fig. 1 [2]. Air is injected into a secure storage area via a compressor which consumes off-peak power, which is generally cheaper. This air is then cooled and stored in a leak-proof subsurface reservoir, typically a natural cavern, salt cavity or aquifer. When electricity is in demand, the air is channeled into a conventional gas turbine expander to be used in the combustion of fuel for the generator.

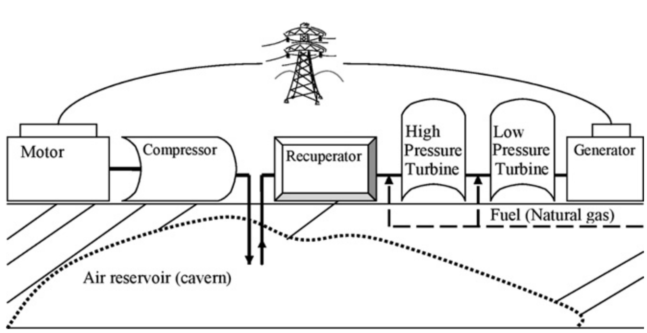

Fig. 1. Operation of a CAES system.

The amount of volume required for a reservoir is related to the desired capacity of a power plant; naturally, a larger reservoir makes it possible to compress more air and hence generate more power. While such a system is optimal at large scales with higher storage and production capacities (around 50–400 MW), it is important that the reservoir volume and plant capacity are properly configured for maximum efficiency. The compressed air can be stored for up to one year, depending on the quality of the seal of the reservoir. Conventional NGTs require 20–30 min for a normal start-up, and this is one of the fastest start-up times compared to other thermal power plants. CAES, on the other hand, can have an emergency start-up time of around 10 min and a normal start-up of 12 min, and this makes it possible for such a system to be used as an alternative power source for load changes or drops in power generation. Since the system is underground, it is not visible, and it also produces lower emissions, which is also advantageous [3].

Energy storage allows for more efficient usage of baseload generation as it significantly decreases the requirements of extra power and reserve levels for peak demand hours. As such it is an economically viable option and has the potential to play a vital role in deregulated power markets. Since the direct storage of electricity is quite expensive, power is stored in other forms, and when electricity is needed, the stored form of power is then transformed into electricity. In deregulated power markets, the supply and demand of electric power determines the hourly market clearing price. Lower demand for electricity drives prices down, while increased demand pushes prices up. Demand usually displays a cyclic pattern in which demand increases during the day and decreases to a minimum at night, and this pattern is reflected in the price of power during a 24-hour period. When prices are low and there is space is available, the system compresses air into the storage area. Then when prices increase to a sufficient point, the system utilizes that compressed air for the generation of electricity for the market. In this way, storage improves the reliability of the supply of electricity while also increasing the productivity of existing power plants and transmission facilities. The storage of power can also be beneficial in that it reduces the costs necessary for the upkeep of these facilities.

Since the demand for energy has been on the rise, energy storage technologies have become increasingly important as a field of research. Research has also been driven by an increased focus on greenhouse gas emissions, sharp increases in the price of natural gas and coal in international markets, and radical shifts in the demand for power during the day and night. Investments in renewable energy resources such as wind and solar have increased in recent years in an effort to both reduce greenhouse gas emissions and increase the mix of generation resources. However, wind and solar resources are intermittent and it is difficult to obtain the same level of power output from these plants for a given time interval. Energy storage technologies have been proposed as a means for load leveling and balancing the rapid load drops caused by wind and solar resources when demand increases. One study presented three computer-based approaches to optimize the operation of CAES in light of fluctuating market prices: dynamic programming, energyPro and EnergyPlan [4]. This study used a historical index of market prices in Denmark to calculate average daily prices, and this was used to estimate revenue and costs with optimized operating strategies. In [5], the authors discussed the role of CAES in future energy systems, and developed a simulation methodology for the Danish market for various scenarios of wind and combined heat power production. The authors developed a methodology to estimate the value of CAES when it is combined with a transmission-constrained wind farm, and they conducted economic analysis to compare wind-sited and load-sited energy storage systems [6]. In [7], the authors compared electrical energy storage systems, including a detailed discussion of the characteristics of CAES, pumped hydro, batteries, superconducting magnets and capacitors. The authors in [8] developed a methodology to evaluate the value of CAES in arbitrage and energy reserve markets. They presented a co-optimized CAES dispatch model for conventional and adiabatic systems and quantified the value of these in such markets as PJM, CAISO, MISO and NYISO. In [9], authors evaluate the economics of energy storage in New York in an environment where regulation and arbitrage exist. Techno-economic comparisons of energy storage systems are evaluated in [10] for island autonomous electrical networks. In [11], a study is presented on transmission when there is energy storage available. These three papers show that the need for energy storage is investigated as the demand for energy is increasing. Authors develop a monte carlo based method to evaluate CAES investments in [12]. It is assumed that the plant operates in liberalized energy market under uncertain electricity prices. The value of CAES is evaluated using net present worth analysis and results are presented. In [13], authors investigate the economic and technical justification of large-scale CAES systems. The analysis is developed for an idealized advanced adiabatic CAES and it is shown that it is feasible for some cycle efficiencies.

In [14], the authors examined a stochastic model to evaluate CAES when there is a significant amount of wind capacity in the market. The author in [15] analyzed CAES in a model that is integrated with wind resources and demonstrated the affordability of electricity in this hybrid system. This study compared the technologies and costs of wind power, and analyzed how CAES can be used to increase the utilization of wind energy. In [16], the authors presented an optimum design approach for the CAES system, demonstrating how costs can be decreased. Authors analyzed the performance of CAES for dry regions and the economic feasibility of the system in [17]. In [18], the author developed a periodic dynamic programming method to determine charging and discharging times and duration in an effort to maximize benefits over the planning horizon; a numerical example was presented to verify the methodology in the determination of the operations of a CAES plant. The thermodynamic and techno-economical analysis for CAES is presented in [19]. The parameters that affect the thermodynamic functioning and also techno-economical performance are determined using exogenous electricity prices. These parameters are provided to be used in design process of a CAES. The researches that integrate the CAES and wind energy were published recently. Using the fast ramp-up rate of CAES against the intermittency of wind energy to reach a stable load was discussed in [20–23]. Authors in [24] also discuss the possible benefits of CAES for wind power applications after reviewing the resources, technologies and developments in CAES. The optimum size and design of CAES is another subject of interest. In [25], the structure of a rock cavern is analyzed with respect to thermodynamic and geomechanical performance. On the other hand, different CAES plant configurations are evaluated and analyzed in [26]. The efficiency of each configuration is analyzed under varying operating conditions and simulation results are presented. Authors in [27,28] present an overview of current and future energy storage technologies. CAES is compared with other technologies and future research topics are provided.

As some of the above studies discussed, a CAES system releases compressed air during peak daytime hours to power a turbine or generator and thus optimizes its schedule while maximizing its revenue. However, the market prices of electricity and natural gas fluctuate hour to hour, and a CAES system will run only if it is economically profitable. Cost estimates must also include the start-up costs for the compressor and expander, and for that reason it is essential to pinpoint a compression and generation schedule given a set of forecasted power and natural gas prices during the course of a year. In light of these issues, in this paper we develop an integrated evaluation methodology for the economic-operational dispatch of a CAES system in an environment where the prices of electricity and natural gas are uncertain. We first develop a mixed integer linear program-based simulation model to optimize the schedule of a CAES system, and then we develop a probabilistic model to estimate the forward hourly prices for electricity and natural gas. The outputs are then used to analyze the economic efficiency of the system for given price scenarios and operational characteristics. For the sake of decision-makers, we also present an analysis for the long-term economics of a CAES investment. The remainder of the paper is as follows. The next section sets up the formulation of the problem and model details. The solution framework is then presented in Section 3. Section 4 provides the numerical analysis and particularities concerning how a system could operate in the Turkish power market. In Section 5, concluding remarks are given.

2. Problem formulation

CAES has a fairly low capital cost compared to other energy storage technologies, and a CAES unit can compress air or generate electricity at any time. In such systems, the most important issue is scheduling the compression of air and generation of power with the release of compressed air. To schedule a CAES system efficiently, it is necessary to know the market prices or at least be able to forecast possible market prices. Another critical issue is the price of the natural gas used in the CAES system, as this directly impacts profits and costs. Hourly profit is the revenue acquired when electricity is sold on the market, minus the variable and operating costs, the cost of natural gas, and the sum of start-up costs. The sum of hourly profits over a year thus represents the total profits for that year. In CAES analysis, the capacity of the compressed air storage facility is a critical factor. We can assume that a facility starts with a full inventory of compressed air and finishes with a full inventory of compressed air; the issue, then, is efficiently using that air inventory to maximize profits. The schedule of compression and generation is thus based on relative prices and the capacity of the storage facility. In other words, generation is scheduled when hourly electricity prices are high enough to cover the cost of natural gas and operating costs, while still allowing for profit. Compression is then scheduled when power prices are low enough to ensure minimum costs so that electricity can later be sold at profitable levels. In our model, we did not include fixed costs as they do not affect scheduling; the model is given as follows:

$$\text{Max} \sum_{n=1}^{N} \sum_{t=1}^{T} \left[G_{n,t}(Q_G(MP_{n,t} - VOM_n^g) - Q_{CT} H_{CT} N_{n,t}) - \frac{(MP_{n,t} + VOM_n^C) Q_C P_{n,t}}{\eta_g \eta_C} - S_n^C U_{n,t}^C - S_n^g U_{n,t}^g \right] \quad (1)$$

S.t.

$$I_{n,t+1} - I_{n,t} + \kappa G_{n,t+1} - P_{n,t+1} = 0 \quad (2)$$

$$G_{n,t+1} \le \beta I_{n,t} \quad (3)$$

$$I_{n,f} = I_{n,l} = \theta \quad (4)$$

$$U_{n,t}^C \ge P_{n,t} - P_{n,t-1} \quad (5)$$

$$U_{n,t}^g \ge G_{n,t} - G_{n,t-1} \quad (6)$$

$$P_{n,t}, G_{n,t}, U_{n,t}^C, U_{n,t}^g \in \{0,1\} \quad (7)$$

Eq. (1) gives the objective function which is the revenue minus the cost of natural gas, variable operating costs and start-up costs for year n. Notice that it includes the generation revenue, the cost of power used to compress air into the reservoir, the cost of the natural gas used in the CT and the start-up costs. Eq. (2) represents the changes in the air inventory. The inventory is measured in units of generation hours that can be acquired from the stored air in the reservoir. The air inventory at time $t+1$ in year n is equal to the air that was available at time t plus the injected air and minus the used air for generation. Eq. (3) gives the relationship between the air inventory and possible generation hour. The unit generation in hour $t+1$ of year n should be less or equal to the possible number of generating hours for each compression hour. Eq. (4) states that the inventory starts and ends with a full amount of air each year. The start-up times directly affect the start-up costs, so it is necessary to determine the start-up hours. Eqs. (5) and (6) are the binary constraints to ensure the start-up times for the compressor and expander. Eq. (7) represents the binary equations that have a value of 1 if there is generation, compression, start-up in the compressor and start-up in the generator, respectively. The model is a mixed integer linear problem (MILP) that determines an optimum schedule of generation/compression for each hour in a year.

2.1. Modeling the electricity and natural gas prices

Note that $MP_{n,t}$ and $N_{n,t}$ are needed to find a solution to the MILP. The power price is strongly load-dependent, highly volatile, seasonal, and consumption-dependent, and energy consumption, fuel costs, availability of fuels, equipment capacity and market participants' behavior are stochastic. The parameters lend a stochastic nature to the price of electricity and natural gas. However, $MP_{n,t}$ and $N_{n,t}$ are not independent of $MP_{n-1,t}$ and $N_{n-1,t}$. In other words, electricity and natural gas prices are dependent on the prices of past performance. Prices follow a similar pattern given that seasonal periods, demand and temperature follow a similar pattern. However, changes in electricity prices and natural gas prices may differ. Since we are interested in long term forward prices, we define a base year with available hourly power and natural gas prices. We then define the annual fluctuations in prices as a discrete time markov chain (DTMC), and calculate the hourly prices for forward years based on the percentage changes.

Let $r(n)$ and $s(n)$ be the random variables that represent the percentage changes in power and natural gas prices in year n respectively. The random variable $r(n)$ is modeled as a DTMC consisting of $N+1$ states, $\{A_0, A_1, \ldots, A_N\}$, and a transition probability matrix of P_r. To compute the long term, we focus on the steady state of the process ($t \to \infty$). The steady state probabilities for power prices $q=[q_0,q..q_N]$ are computed by solving the matrix equation $q=qP_r$. The cumulative distribution (CDF) of percentage changes is given by

$$F_r(x) = \sum_{n=1}^{A_N \le x} q_n \quad (8)$$

$s(n)$ also has a DTMC consisting of $N+1$ states, $\{B_0, B_1, \ldots, B_N\}$, and a transition probability matrix of T_s. The steady state probabilities for natural gas prices $v=[v_0,v_1..v_N]$ are computed by solving the matrix equation $v=vT_s$. The CDF of percentage changes is given by

$$H_s(x) = \sum_{n=1}^{B_N \le x} v_n \quad (9)$$

Note that the random variables $r(n)$ and $s(n)$ are sign free percentages. It then follows that the hourly prices for power and natural gas for year n can be calculated as below:

$$MP_{n,t} = MP_{n-1,t}(1+r(n)) \quad (10)$$

$$NP_{n,t} = NP_{n-1,t}(1+s(n)) \quad (11)$$

The VOM_n^C, S_n^C values are related with the amount of electricity used during the operation and start-up, respectively. They can then be approximated (updated) using the same logic, as

$$VOM_n^C = VOM_{n-1}^C(1+r(n)) \quad (12)$$

$$S_n^C = S_{n-1}^C(1+r(n)) \quad (13)$$

The VOM_n^g, S_n^g values are related with the amount of natural gas used during the operation and start-up, respectively. Hence, their formulation is represented as

$$VOM_n^g = VOM_{n-1}^g(1+s(n)) \quad (14)$$

$$S_n^g = S_{n-1}^g(1+s(n)) \quad (15)$$

3. Solution framework and sensitivity analysis

In order to evaluate the long-term revenues for CAES, we develop a multi-period optimization method that is integrated with a DTMC-based monte carlo simulation, taking into account two different and separate modules. The first module deals with the data preparation, and the DTMC is implemented during this process. A monte carlo-based procedure is employed to deal with the DTMC of hourly prices. The data is then fed into the optimization module that will schedule the CAES facility to maximize its profits over the year. Fig. 2 gives the pseudocode of the solution framework.

It is important to note that the algorithm is designed to initialize from the current time and then it calculates the forward operational revenues based on the optimum schedule of the CAES in the power market. Hence, the current cost data is employed to initialize VOM_0^C, VOM_0^g, S_0^C, S_0^g, $MP_{0,t}$ and $N_{0,t}$. Then, as the prices are updated based on the forward estimations, the parameters are also updated so that they have a consistent operational medium. Note that the air inventory starts full and ends full each year. The algorithm determines hourly CAES dispatch by maximizing net revenue based on hourly power and natural gas prices, and the cost of natural gas, as well as operating, maintenance and start-up costs subject to operational constraints. The profit for each year is then used to calculate the NPV and payback to measure the economic performance of the investment. The revenues are discounted as follows:

$$\mathrm{NPV} = \sum_{n=1}^{N} \frac{Rv_n}{(1+f)^n} - CC_0 \tag{16}$$

The capacity of the air storage area, as well as the generation and compressor, plays an important role in the economic performance of the system. The capital cost is also dependent upon the scale of the components. A sensitivity analysis is performed to observe the effect of the size of each component on system performance. Two parameter tests, for air storage-compressor capacity, air storage-generation capacity and compressor capacity-generation capacity, are performed to assess the effect of each component on the economic performance of the investment.

```
Start
For y=1 to Y do
Set base year=0, I_s=Θ, Q_C, Q_G, n=1
Initialize VOM_0^C, VOM_0^g, S_0^C, S_0^g
For t=1 to T=8760 do
Get MP_0,t and N_0,t
End for
For n=1 to N do
Sample r(n) and s(n) from continues random distribution
Round r(n) and s(n) to the nearest discretized values
Compute and update VOM_n^C, VOM_n^g, S_n^C, S_n^g
    For t=1 to T do
    Compute the MP_n,t and N_n,t
    End for
Optimize the scheduling of the CAES for year n using the optimization module
Calculate the profit for year n
End for
Calculate NPV and payback
End for
End
```

Fig. 2. Pseudocode of the multi-period optimization and simulation.

4. A numerical case study in a Turkish power market

We develop a numerical analysis for Turkey to validate the proposed model. We assume that the value of investment for a CAES must be determined for investment decisions. We use a reference CAES system given in [5] for the analysis. The system has a turbine capacity of 360 MW, compressor capacity of 216 MW and a storage capacity equal to 68 h of generating capacity. The efficiencies of the compressor and turbine are also included. There are different approaches to model the efficiency of a system. Authors in [29] present details of the efficiencies in a CAES system. The efficiency of the storage is calculated using charging efficiency (exergetic efficiency of the compressor), cavern efficiency (exergetic efficiency of the storage) and discharge efficiency (exergetic efficiency of the turbine). The isentropic efficiency, energy efficiency, primary energy efficiency, system electric efficiency and thermal efficiency are some other types of efficiency that are considered. Since the main objective of this paper is the economic analysis and scheduling of the system, a simplified system is preferred for the analysis. The CAES that is analyzed in this paper is a reference case given in [4,4]. In these papers, authors consider the efficiency of the compressor and the efficiency of the turbine for their analysis. The efficiency of the compressor (η_c) is defined as the energy input to the storage per power input to the compressor. On the other hand, the efficiency of the turbine (η_g) is defined as power output per energy input to the storage. The efficiency of the compressor (η_c) is defined as the energy input to the storage per power input to the compressor. Hence, 0.691 is the amount of energy input to the storage per 1 unit of power input the compressor. On the other hand, the efficiency of the turbine (η_g) is defined as power output per energy input to the storage; 2.44 is the amount of power units per 1 unit of energy input to the storage.

The details of the reference case and the sensitivity ranges are given in Table 1. The sensitivity range is selected in such a way that the performance of smaller systems can be analyzed. The real systems are smaller systems or peers of the reference case which are closer to reality. We assume that the system starts operation in 2011 and runs for $N=30$ years (each $T=8760$ h) until 2041. The model is implemented according to a General Algebraic Modeling System (GAMS) which is a high-level modeling system for mathematical programming problems. The software is suitable to build large scale and complex modeling applications. CPLEX 12.5 solver is used which is included in GAMS.

4.1. The analysis of the reference case

To initialize the algorithm, 2010 is assumed as the base year with $I_{0f}=68$ h. We analyze the historical data for the Turkish

Table 1
Details of the CAES system.

System	Notation	Sensitivity range	Reference case [4,5]
Compressor capacity (MWhe)	Q_C	[40–216]	216
Compressor efficiency	η_c	0.691	0.691
Storage capacity (generation hours)	θ	[10–68]	68
Turbine capacity(MW)	Q_G	[70–360]	360
Heat rate (GJ/MWh)	HCT	3.998	4.221
Turbine efficiency	η_g	2.44	2.44
CAES system cost ($106)	CC_o	Capacity dependent	228
Life time	N	30	30
Interest rate	f (%)	7	7
Variable compressor O&M cost ($/MWh)	VOM_n^C	Capacity dependent	2.91
Variable turbine O&M cost ($/MWh)	VOM_n^g	Capacity dependent	3.5

natural gas and power market for the period 1990–2010 and transform the continuous space of the annual changes in gas and power prices into a discrete space, as in Tables 2 and 3 respectively. The transformed data is then used to compute the steady state probabilities of the markov chains.

The costs are approximated as $VOM_0^C = 2.84$ \$/MW h, $VOM_0^g = 3.34$ \$/MW h, $S_0^C = 5618$ \$, $S_0^g = 8427$ \$. The next step is to obtain the power prices and natural gas prices that will be used as the base for the future forward price estimations. The power price is a stochastic variable which depends on such issues as load, temperature, unit breakdowns, and workdays. The hourly price in a day displays a cyclic pattern with random deviations which must be estimated. The model takes the hourly power price as the input for the scheduling. Fig. 3 shows the hourly power prices for 2010 in the Turkish power market [30].

Another input for the scheduling model is the hourly natural gas prices. The price of natural gas price depends on supply–demand in the wholesale market which is highly related with international politics, market conditions and stability. Fig. 4 shows the gas prices for 2010.

Table 2
Continuous to discrete space transformation for gas prices.

Range (%)		Discrete value (%)	Steady-state probability
−20	−10	−15	0.070
−10	0	−5	0.072
0	10	5	0.357
10	20	15	0.214
20	30	25	0.141
30	40	35	0.145

Table 3
Continuous to discrete space transformation for power prices.

Range (%)		Discrete value (%)	Steady-state probability
−25	−15	−20	0.073
−15	−5	−10	0.069
−5	0	−2.50	0.357
0	5	2.50	0.214
5	15	10	0.071
15	25	20	0.143
25	35	30	0.071

The simulation is run $S=100$ times. Note that the model provides a schedule of compression and generation based on the market price and natural gas price, of which the market price determines the revenue and natural gas price determines the cost. Fig. 5 shows the compression and generation schedule for a 1-week period in 2011. The period is selected arbitrarily to show the operation details. Note that compression and generation are represented as 1 when they are functioning.

The amount of air inventory in the air storage area shows gradual changes throughout the year in 2011, as shown in Fig. 6 (in terms of generation hours). The inventory starts full and ends full. When the power price is low, the system compresses air into the inventory, and hence the level rises. This air is then used

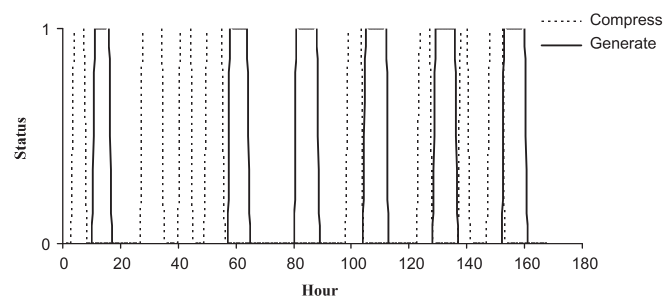

Fig. 5. Generation-compression schedule for the CAES system.

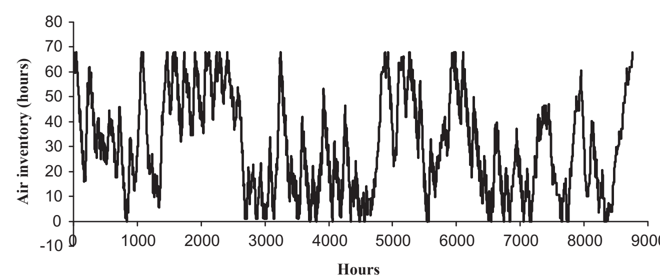

Fig. 6. The change in the air inventory in the CAES system in 2011.

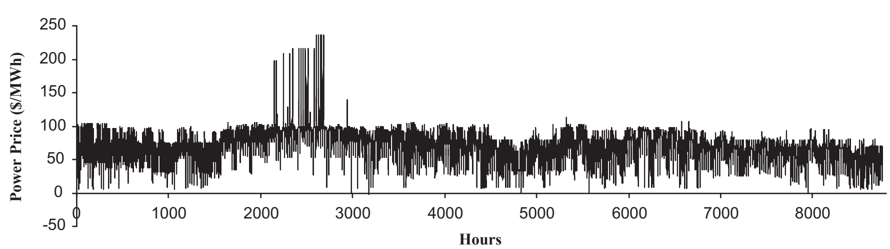

Fig. 3. Hourly electric power prices in the Turkish power market, 2010.

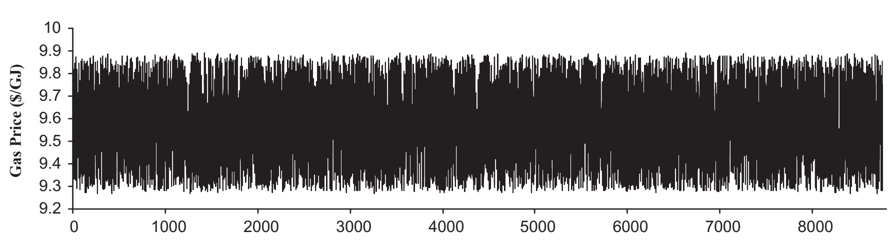

Fig. 4. Hourly natural gas prices in Turkey, 2010.

when power is too expensive or when the demand is too high and inventory goes down. In this way, the pattern in power prices affects the air inventory which drops when power prices are high, and the inventory fluctuates parallel to power prices. It is also worth mentioning that the air inventory becomes full when power prices are high, as can be seen prior to hour 5000.

The objective of the optimization module is to maximize profits over the year, and the objective of the simulation is to identify the profits for 30 years and the corresponding NPV in each replication. Fig. 7 shows the statistics of the revenues of the 100 simulations. Each replication runs the DTMC-based CAES optimization model and provides an optimum schedule and maximized profit for each year. The values represent the mean, standard deviation and 5% and 95% percentiles of profits found in 100 simulations for the corresponding year.

The NPV of the mean profits is $75.15 Million, and the statistical results of CAES support the investment decision. The percentiles, along with the standard deviation, can be evaluated each year during the decision-making process. We also take into consideration payback time, which is another critical element. Fig. 8 shows the change in profits and in the balance of the investment, indicating that the project will pay for itself in 2022 according to the simulation results. The investment is economic in terms of NPV value, and the rate return on investment (ROI) is 9%, which is an acceptable figure.

4.2. Sensitivity analysis of θ, Q_G, and Q_C

An important issue in the operation of a CAES system is the size of the air storage, as well as the size of the generation unit and the compressor. If one or more of these components is oversized, the performance of another component in the system may be compromised. On the other hand, the required capital cost is dependent upon the size of the components. The economic value and the ROI of the system are determined by the proper size of the components and their appropriate performance.

In this section, we apply two-parameter sensitivity tests for the operational analysis of the system, given that one parameter is constant. The sensitivity range for the parameters is given in Table 1. Three different setups are taken into consideration, using combinations of θ, Q_C and Q_G. The increments are determined for each parameter, which are set to determine the simulation parameters. An increment of 3 h is used for θ, and 5 MW increments are used for Q_C and Q_G. Fig. 9 shows the analysis results for θ and Q_C with Q_G=360 MW. For each parameter set, the algorithm is run and the results of 100 simulations are collected. The figure shows the NPW and ROI that are found based on the mean profits. The cost breakdown of a typical CAES system is provided in [8]. The capital cost is adjusted based on the reference case and the cost breakdown ratio, meaning that the capital cost decreases for smaller capacities.

The NPW and ROI of the system are highest when Q_C=40 MW and θ=10 h. They gradually decrease and reach the lowest point when Q_C=216 MW and θ=68 h. When capacities are lower, compression and generation occur more frequently. As a result, ROI reaches the highest levels as utilization increases per generation hour and per MW of compression.

Fig. 10 shows the NPW and ROI values which are calculated based on the simulation results of θ and Q_G with Q_C=216 MW. The economic performance of the system is negative and lowest for θ=10 h and Q_G=70 MW. The NPW becomes positive at θ=54 h and Q_G=288 MW, and highest at θ=68 h and Q_G=360 MW. Generation capacity directly affects the revenue acquired from power sales, and a storage area with a smaller capacity limits the extent to which the compressor can be used. Consequently, the economic returns resulting from a smaller generation capacity do not cover the associated variable and capital costs. The results also demonstrate that it is necessary to have a proper combination of generation capacity and compression capacity to achieve optimal economic performance.

Fig. 11 illustrates the sensitivity results of Q_C and Q_G with θ=68 h. The NPW and ROI are lowest at Q_C=40 MW and Q_G=70 MW and

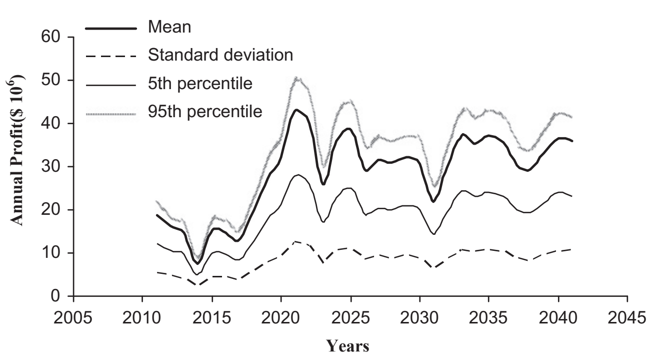

Fig. 7. Summary statistics for the 100 simulations.

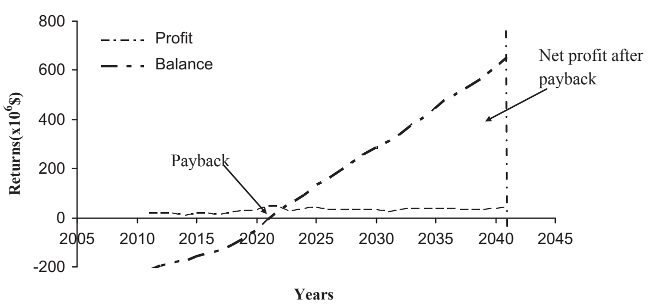

Fig. 8. Annual profits and project balance.

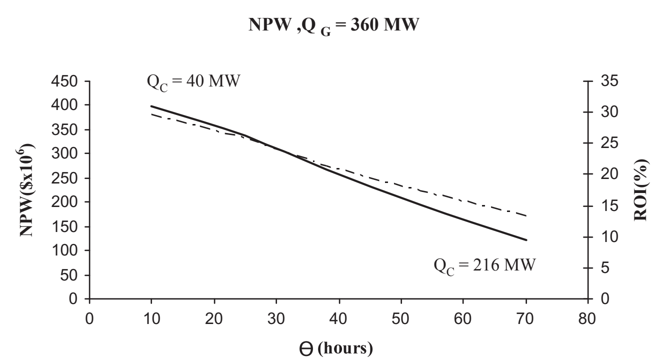

Fig. 9. The effect of θ and Q_C on the economic performance of CAES.

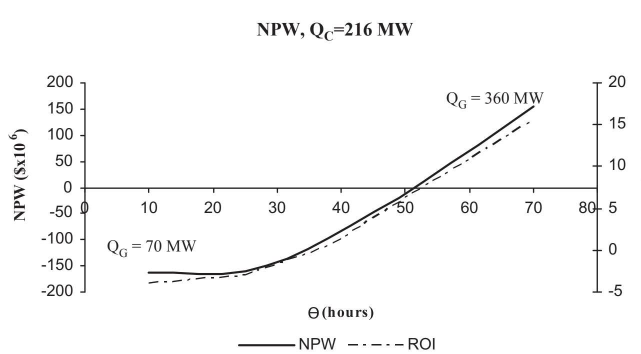

Fig. 10. The effect of θ and Q_G on the economic performance of CAES.

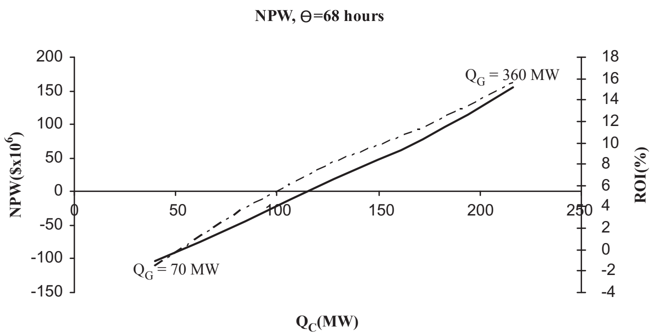

Fig. 11. The sensitivity of Q_G and Q_C on the economic performance of CAES.

highest at $Q_C=216$ MW and $Q_G=360$ MW. The system becomes economically feasible at around $Q_C=130$ MW and $Q_G=210$ MW for a given $\theta=68$ h. Economic revenue is insufficient to cover the capital and operational cost of the system below these capacity levels. The proper balance of compression and generation capacities can be estimated from the figures for higher economic performance and better operational performance. The shift is not linear; however, it can be approximated to a piecewise linear equation for simplicity.

5. Conclusion

Energy storage systems are becoming increasingly important as they can offset load deviations, take over in the case of thermal unit breakdowns, and increase the efficiency of resource use. As such, in today's world the utilization of storage system technology has taken on greater precedence and proper scheduling is critical to ensure maximum efficiency. In scheduling CAES systems, the two main issues are the prices of electricity and natural gas. In this paper, a MILP was first developed, followed by a DTMC-based probabilistic model to estimate forward market prices. Then an algorithm that includes two separate modules was employed to optimize the operation of the CAES over a period of one year and calculate the annual profit based on the estimated market prices. Using the probabilistic price estimations, the annual profits of 100 simulations were identified for the period 2011–2041. NPW, ROI and payback were also calculated to analyze the economic viability of the investment. The results of the 100 simulations for the referenced CAES design indicated that the investment would be economically viable for the given market prices and could be implemented.

Sensitivity analyses were carried out to estimate the effects of compressor capacity, generation capacity and air inventory, and the results of these indicated that differing yet still successful designs for CAES can be developed in terms of efficiency and economic viability as they indicate the effect of each parameter on the economics of the system. Additionally, this paper presented an analysis of how such a system would operate in Turkey, a developing country which has fluctuating and uncertain market prices. This solution methodology can be applied to estimate the economic value of CAES in other countries as well, and it will also be helpful for decision makers considering making investments in CAES technology.

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