**THE VALUE OF ARBITRAGE FOR ENERGY STORAGE:**

**EVIDENCE FROM EUROPEAN ELECTRICITY MARKETS**

**Dimitrios Zafirakis1,\*, Konstantinos J. Chalvatzis2,3, Giovanni Baiocchi4, Georgios Daskalakis2**

1Piraeus University of Applied Sciences, Mechanical Engineering Dept,

Soft Energy Applications & Environmental Protection Lab, Athens, 12244, Greece

Tel: +30 210 5381580, Εmail: [dzaf@teipir.gr](mailto:D.Zafirakis@uea.ac.uk)

2Norwich Business School, University of East Anglia, Norwich, NR4 7TJ, UK,

Tel: +44 (0)1603 59 7241, Εmail: [K.Chalvatzis@uea.ac.uk](mailto:D.Zafirakis@uea.ac.uk)

3Tyndall Centre for Climate Change Research, University of East Anglia, Norwich, NR4 7TJ, UK

4Department of Geographical Sciences, University of Maryland, College Park, MD 20742, USA

Tel: +1 301 405-2342, Εmail: baiocchi@umd.edu

**Abstract**

We use a portfolio of energy trade strategies to determine the value of arbitrage for pumped hydro and compressed air energy storage across European markets. Our results demonstrate that arbitrage opportunities exist in less integrated markets, characterised by significant reliance on energy imports and lower level of market competitiveness. We show that, among all strategies tested, arbitrage value maximizes for the weekly back to back energy trade strategy. Moreover we estimate the optimum size of energy storage systems in terms of arbitrage value for each different electricity market and evaluate the potential of arbitrage to support investment in the sector. Finally, it is argued that energy storage can take over multiple roles as a necessary positioning to facilitate financial profitability.

**Keywords**

Pumped hydro storage, compressed air energy storage, energy trade, wholesale market, spot price, production cost

**1. Introduction**

The debate on what roles can energy storage support in the power sector and contemporary electricity markets has been prominent for more than a decade [1]. Despite the fact that such systems can provide a bundle of services [1,2], including avoidance of costly interconnecting infrastructure and emission reduction [3], investment remains limited due the absence of a concrete valuation framework and the high capital costs of most energy storage systems. Nevertheless, research on energy storage and its role in supporting increased integration of renewable energy sources (RES) has been intensive [4-14]. In this context, novel operation strategies that consider collaboration with RES challenge State support for energy storage through the production of social welfare effects [15-17]. Arguing that energy storage can take over multiple roles, our notion is that a portfolio of value-adding services [18-22] can produce further revenue streams; thus facilitate investment in the sector more effectively. Given that, the main scope of the specific paper is to determine what is the value of one such revenue stream, i.e. arbitrage, for grid-scale energy storage across European markets.

In economics and finance, arbitrage is the practice of taking advantage of a price difference between two or more markets: striking a combination of matching deals that capitalize upon the imbalance, the profit being the difference between the market prices. Arbitrage practiced by energy storage on the other hand refers to the application of energy trading strategies within an electricity market environment, aiming to buy energy from the grid at low price and sell it back to the grid at a meaningfully higher price; i.e. take advantage of spot market price spreads (between off-peak and peak demand hours) that can produce value, considering also energy conversion losses during the storage system operation. Similar research has been conducted in the past [20,23-26], yielding that arbitrage is not in itself adequate to support energy storage investments; thus welfare gains of energy storage services need to be identified in order to elicit State support [27-29]. Nevertheless, in most of these studies, comparison between the system operational cost and the arbitrage value is used as a measure of economic performance, disregarding capital costs and the system capacity factor. Furthermore, a serious limitation of this body of literature relates to study of exemplary cases which look at fixed system sizes (i.e. main system components are not allowed to vary in size), normally corresponding also to price-taker units[[1]](#footnote-1), along with one type of energy storage technology, e.g. pumped hydro storage (PHS), and a single power market examined, hindering in this way the generalization of conclusions.

To capture broader market and technology effects, examination of the arbitrage value across different European electricity markets is undertaken for PHS and compressed air energy storage (CAES), taking also into account variation of the system size. For this purpose, we use historical, hourly spot price data for the period 2007-2011, for the electricity markets of Nord Pool, EEX, UK, Spain and Greece. The selection of the specific markets aims to reflect differences in the value of arbitrage in association with market characteristics such as fuel mix and market competition. In terms of arbitrage strategies, we apply both time and price based signals on a daily and weekly time step. To this end, we estimate the arbitrage value and its net difference with the system electricity production cost. Moreover, in the case of price signals we also study variable system sizes and provide optimum size results concerning both the value of arbitrage and its net difference with the system production cost. Thus, innovation of the specific paper lies on the simultaneous study of four different arbitrage dimensions for energy storage, these referring to the different European power markets investigated, the different energy storage technologies examined, the variable size of energy storage system components considered and finally, the different energy trading strategies applied.

Following this introduction, the selected electricity markets are described in Section 2, while in Section 3 we analyse the applied methodology and arbitrage strategies. Sections 4 and 5 present the application results and discuss the association of the arbitrage value with market characteristics, energy storage technology and trading strategy used. The paper concludes with Section 6, where the main findings are critically presented.

**2. European Electricity Markets**

In order to capture different market characteristics we examine both regionally integrated and isolated electricity markets of different competition level, fuel mix characteristics (see also Figure 1) and cross-border transmission capacity. More precisely, the markets of Nord Pool, EEX (European Energy Exchange), UK (APX), Spain and Greece were selected as representative examples.







Figure 1: Long-term electricity supply fuel mix for the examined electricity markets

*2.1 The market of Nord Pool*

Nord Pool is the first and largest market for power trading in the world [30]. It comprises of the former Nordic markets (i.e. the Danish, the Finish, the Swedish and the Norwegian) that were deregulated in the early 90s to engage into an integrated new market along with Estonia and Lithuania deregulated in the late 2000s. The participation of different countries in that case ensures a liquid market environment that can handle extreme price events effectively [31] and provides a relatively diverse fuel mix. Nevertheless, electricity generation in Nord Pool is mainly based on hydropower and nuclear, with sufficient power exchange potential playing an important role (Figure 1). Nord Pool facilitates large-scale wind energy integration in Denmark [32,33] and is highly competitive; thus, in the context of this paper, Nord Pool is used as an integrated, mature and highly energy secure market, with sufficient regulating and balancing ability deriving from its hydro and power exchanging potential.

*2.2. The European Energy Exchange (EEX) market*

The EEX [34] was founded in 2002 from the merger of the two German power exchanges in Frankfurt and Leipzig. Later, in 2008, EEX entered a close cooperation with Powernext, during which both partners integrated their power spot and derivatives markets. EEX now holds 50% of the shares in the joint venture EPEX SPOT which operates the spot market for Germany, France, Austria and Switzerland. As a result, EEX comprises a diverse electricity market that is dependent on fuel imports in order to support nuclear power and natural-gas based generation. At the same time, it is a market that despite its considerable power exchange potential, suffers relatively frequently from extreme price events.

*2.3 The UK market (APX)*

APX Power UK was established in 2000 as Britain’s first independent power exchange [35]. In 2011, coupling with Netherlands -through the BritNed electrical cable- brought increased liquidity to the local market from the very liquid Power NL spot market and beyond from Germany, Belgium, France and Norway that also affected electricity prices. In the meantime, UK is increasingly dependent on primary energy imports [36,37] while presenting –until 2010- little activity in electricity trade (see also Figure 1). As a result, APX can be seen as a less integrated, highly competitive and import-dependent market which is in a transitional stage of decarbonising its fuel mix [38] and enhancing its electricity trade.

*2.4 The Spanish market*

In 1998, Spain and Portugal formed the integrated, pool-structured Iberian market, known as Mibel [39]. Integration between the two markets has intensified over the years [40,41], resulting to minimum price differential explained by greater convergence of the two countries’ fuel mix and the effectiveness of the cross-border trading mechanism. However, Spain does not enjoy equal interaction with neighbouring European regions, with its cross-border transmission capacity to France limited to less than 2.8GW. Moreover, the Spanish market suggests an ideal example of high RES contribution [42] with almost 1/3 of its total electricity generation coming from hydro, wind and solar energy. To facilitate this large-scale RES integration (mainly wind), natural-gas power plants are employed to provide the required flexibility, similar to the UK. Thus, Spain is a market of high RES contribution that depends on fuel imports and enjoys a close synergy with Portugal but limited connectivity to the rest of Europe.

*2.5 The Greek market*

Greece although liberalizing its market in 2001 [43], comprises a deregulated market only by euphemism and should thus be studied as a monopoly. The local Public Power Corporation holds almost 85-90% [44] of the market generating capacity. In this regard, the country is mainly based on the exploitation of local lignite reserves that contribute approximately 50% of the electricity generation fuel mix, followed by natural gas imports that were recently decreased slightly due to economic recession impacts. Moreover, Greece has strong cross-border transmission capacity, including transmission lines to the Balkan region, Italy and Turkey, used mainly for importing energy. Thus, Greece offers an example of a monopolistic market that is largely based on the exploitation of low cost lignite reserves and uses its cross-border transmission capacity to mainly import electricity.

**3. Methodology**

For the purpose of this paper, we use hourly electricity spot price data from 2007 to 2011 for the five markets of Nord Pool, EEX, APX, Spain and Greece. Using this dataset we apply different daily and weekly arbitrage strategies in order to determine the annual arbitrage value of PHS and CAES per unit of energy produced, using time signals on the one hand and price signals on the other. Moreover, we estimate the system mean annual production cost, considering the capital costs as well as the frequency of system operation (or capacity factor) which reflects upon the respective operational costs. Based on that we also determine the net difference between the arbitrage value and the system electricity production cost. Finally, we assume price-taker storage plants and use fixed system size in the case of time signals and variable system size in the case of price signals, where we also proceed to optimization of results using as criteria the maximum arbitrage value and the minimum difference between the system production cost and the arbitrage value.

A more clear view of the applied methodology is provided in Figure 2, where the different problem dimensions are illustrated. Additionally, a short description of the current status of energy storage (paragraph 3.1) and of the two storage technologies examined (paragraph 3.2) is provided in the following sections, along with an analysis of the applied arbitrage strategies and methodology (paragraphs 3.3 and 3.4).

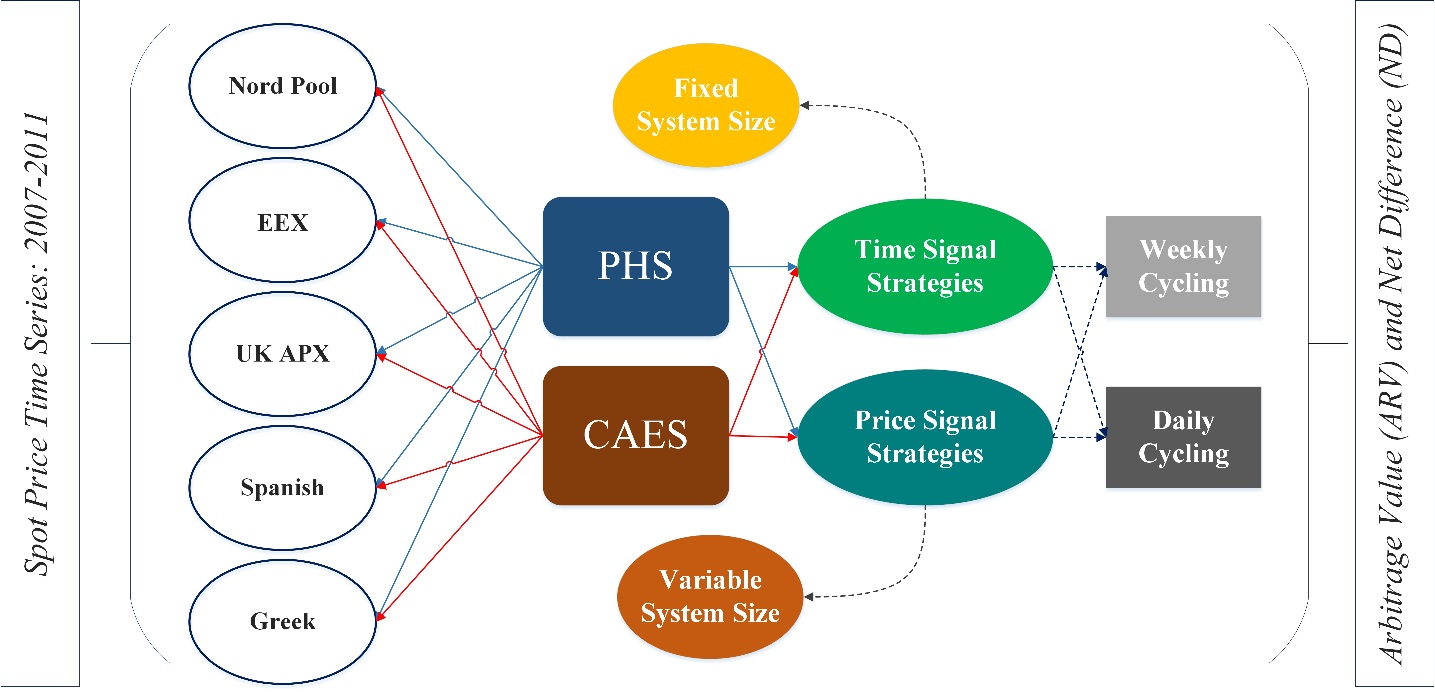


Figure 2: The methodology dimensions of the arbitrage problem under study

*3.1 Energy storage technologies*

During the last two decades, progress met in the field of energy storage is rather significant, mainly owed to the need to support large scale penetration of RES. In fact, recent projections for advanced battery technologies, supporting utility-scale storage applications alone, challenge remarkable global market growth, which by 2025 is expected to generate sale revenues exceeding €3 billion [45]. At the same time, more mature technologies, such as PHS and CAES, seem to revive, and new ones like super capacitors (SCs) and superconducting magnetic energy storage (SMES) are rapidly developing to become commercial.

According to the current status of maturity, energy storage technologies can be classified into three main categories, i.e. mature (deployed) systems, less mature (demo-stage) and early-stage ones. In the first category of mature systems one may encounter PHS, CAES, certain advanced batteries like lead-acid, Na-S and Li-ion, as well as certain flywheel types. In the second, demo-stage category, flow-batteries, SMES and SCs can be found, while in the final group of early-stage systems, adiabatic CAES along with hydrogen can be encountered.

In this context, it is noted that each of the energy storage technologies comes with its own features that makes it more suitable for a certain range of grid services and less favourable for others. For example, bulk energy storage system like PHS, CAES and certain batteries are more suitable for energy management applications, while technologies like SMES and SCs are more favourable for power quality services like frequency regulation. On the other hand, it is normal for the bigger scale systems to be able to capture more grid services and thus more than one value streams in order to maximize asset value and encourage investment in the field through the adoption of portfolios of services. Arbitrage, being also considered among such value streams, implies employment of storage technologies that are able to practice energy trade and thus energy management. As a result, the specific study will focus on the examination of the two most mature energy management storage technologies, i.e. PHS and CAES, and will evaluate their arbitrage performance based on the application of different energy trade strategies in five different European electricity markets.

*3.2 PHS and CAES*

PHS is the most mature bulk energy storage technology [46], with almost 130GWs of installed capacity worldwide. In a PHS system, off-peak energy or energy in excess is used to pump water to an elevated (upper) reservoir. During peak demand or times of energy deficit, water is released from the upper reservoir to operate hydro-turbines. Cycle efficiency of modern PHS could reach 70-80% [47] with more common values being in the order of 65-70% [48], while such systems can take up load in a few tens of seconds and feature a high rate of extracted energy. In general, PHS systems are suitable for applications of energy management, spinning reserve and frequency control.

Similarly, in a CAES system, off-peak or excess power is used [49,50] to compress air into an underground cavern or a tank (at pressures that can even reach 70bars). During periods of peak demand or energy deficit, the required amount of air is released from the cavern, heated with natural gas and fed to a gas turbine where expansion takes place as in the Brayton/Joule cycle. Note that in a CAES system the entire gas turbine output is available to consumption, which also implies considerably lower heat rates (or fuel consumption) in comparison to conventional open-cycle gas turbine plants. Moreover, CAES systems have a satisfying response time and can take up load in a few minutes, while because of their ability to store energy as pressurised air, the respective energy density is higher than that of PHS. Cycle efficiency of CAES, which also includes fuel consumption, is approximately 55%, if also considering waste heat utilization.

*3.3 Arbitrage strategies*

As seen earlier, we apply arbitrage strategies based on either time or price signals and two different time steps, i.e. daily and weekly. In the case of time signals, both long-term and short-term price data is used, with the employed set of strategies considered straightforward for applied practice. Contrariwise, price signal based strategies depend strictly on short-term price signals (currently the static or moving average price of the previous 24h or 168h) and require a greater level of commitment that assumes accurate prediction of next hours’ spot price. During application of all strategies, apart from the annual arbitrage value, the system’s operation frequency (cycling) is recorded through the estimation of the respective capacity factor.

* *Long-term arbitrage* (time signals): In this strategy we use long-term historical spot price data (currently the 4-year period of 2007-10) to determine buying and selling time points during the day/week and apply them for the following year, i.e. 2011. For this purpose, we estimate the long-term hourly average values of spot price on a daily and weekly basis. From the obtained results we use the hour of minimum price as buying signal and the hour of maximum price as selling signal, assuming that exploitation of long-term data could increase the strength of the signals. Note that in the case of the weekly time scale, to increase system frequency of operation and thus reduce systems costs, we allow charging of the system on a daily basis (using the same signal as in the daily time scale), combined with discharging during the maximum price hour of the week alone.
* *Mirror arbitrage* (time signals): The exact same day or week of the previous year is used in this strategy to determine time signals and apply them to the current year’s day/week. Therefore the years between 2007 and 2011 are examined in pairs. Similar to the previous strategy, the selected time points correspond to the minimum /maximum hour of the week or day. The assumption is that the stronger the seasonality in electricity prices the greater the signal reliability will be.
* *Back to back arbitrage* (time signals): In the current strategy, the previous day or week of the same year is used to determine signals for the next day/week. As a result, we get moving time signals that are expected to capture both seasonality and consistency of price patterns during the same year.
* *Static and moving average arbitrage* (price signals): Finally, we borrow the common trading strategies of static and moving average from finance. In that case price signals of the previous 24h or 168h are used to make a buying or selling decision for the next hour, assuming perfect prognosis of the respective spot price. Note that according to price signals, the system is set to operate whenever there is incentive to do so, restricted only by its input/output power and storage capacity. To this end, the system size examined is variable, and optimization is undertaken under the criteria of maximum arbitrage value and its minimum difference with the system production cost.

*3.4 Comparison between arbitrage value and system production cost*

In the first case of time signal strategies, the size of system components is interdependent, owed to the fact that system operation is predefined in accordance with the period of time that the system is set to charge and discharge (considering a full cycle). Thus, if given a certain input power *Nin* for the system investigated, the system energy storage capacity *Ess* and the system power output *Nout* depend on the time period of charging *Δtch* and discharging *Δtdis*, as well as on the system input and output efficiency(*ηin* and *ηout*). More precisely, energyis stored in the system when a time signal for buying is given and is delivered back to the electricity grid when a time signal for selling follows. However, in order to store an amount of energy equal to *Ein*, the amount of energy previously bought *Ebuy* should be somewhat higher, taking also into account the input side energy efficiency (see also equation (1)).

|  |  |
| --- | --- |
|  | (1) |

Furthermore, and if neglecting at this stage the system’s maximum depth of discharge, it is assumed that the entire amount of energy stored during the period of charging is equal to the storage capacity, i.e. *Ein=Ess*. At the same time, the respective energy being sold (*Esell*) is reduced due to the system output efficiency, i.e. *Esell=Ess·ηout*, taking also into account that the system is fully discharged (*Eout=Ess*), i.e. a full cycle of charging and discharging is always executed by the system on either a daily or a weekly basis. Finally, based on the available energy stores *Ess* and time period of discharging *Δtdis*, the system nominal output power *Nout* can be estimated by equation (2).

|  |  |
| --- | --- |
|  | (2) |

Price signal strategies differ from time signal strategies in that they suggest examination of system components, the size of which is variable and independent from one another (see also Table 1). This is owed to the fact that the system may buy and sell electricity during the entire day or week, subject to price signals and the limitations introduced by the size of system components (i.e. input and output power, as well as storage capacity).

On top of that, both input and output system components are set to operate at their nominal point of operation. Considering the above, for each type of strategy applied, the arbitrage value *ARV* is derived from the comparison between revenues (from selling energy to the grid) and expenses (from buying energy from the grid) on an annual basis, with *cspot* being the spot electricity price of each hour examined and *hsell* and *hbuy* corresponding to the hours of selling and buying energy respectively (time step is hourly, i.e. *hsell* = *hbuy =*1). Moreover, to express the annual value of arbitrage per unit of produced energy, the annual energy yield is estimated, with *CF* being the system production side annual capacity factor (year duration of *Δtyear*).

|  |  |
| --- | --- |
|  | (3) |

In this context, although in the case of time signal strategies estimation of the *ARV* is straightforward (since the size of components is dependent on one another), in the case of price signal strategies, where the size of system components is variable, an optimization problem is introduced, i.e. how to maximize the *ARV*. Accordingly, the net difference between the system life-cycle (LC) electricity production cost (*css*=*cPHS* or *css*=*cCAES*) and the *ARV* is estimated, with the former including both installation and maintenance and operation costs that in the case of CAES also takes into account the necessary fuel consumption. The net difference (*ND*=*ARV*-*css*) provides an additional optimization criterion for price signal based strategies which in that case requires determination of the respective minimum. To estimate this however, the system LC electricity production cost (€/MWh) over the entire system service period *nss* (either *nPHS*or *nCAES)* needs to be determined first, assuming in this context -for the case of price signal strategies- that the system will operate under constant *CF* throughout its service period.

To determine the LC electricity production cost of PHS systems, the initial capital cost *ICPHS* is combined with the system maintenance and operation cost for a service period of *nPHS* years, that is expressed with the help of the respective annual coefficient *mPHS* (being a percentage of the initial installation cost). The initial cost is further broken down to the components of water reservoir cost, hydro-turbines’ cost and pumping station cost. In this context, *ct* (€/kW) is the specific purchase cost for hydro-turbines, *cpump* (€/kW) is the respective cost for pumping stations and *cres* (€/m3) corresponds to the specific cost of building a reservoir of certain volume *Vres*. The latter depends on the available head of the installation *Hres* (currently considered at 100m), the water density *ρw*, the gravitational acceleration *g* and the energy storage capacity *EPHS*. Finally, the nominal power of the pumping and the hydropower station are symbolized as *Npump* and *Nt* respectively.

|  |  |
| --- | --- |
|  | (4) |

|  |  |
| --- | --- |
|  | (5) |

|  |  |
| --- | --- |
|  | (6) |

Similarly, the initial cost of CAES includes the components of cavern / tank cost, compressor cost and gas turbine cost, which may also derive from the respective specific cost coefficients *ccav* (€/kWh), *ccomp* (€/kW) and *cgt* (€/kW) and the size of the respective system components (i.e. *Ecav*, *Ncomp* and *Ngt* respectively). Furthermore, the LC maintenance and operation costs for a period of *nCAES* years are estimated with the maintenance coefficient *mCAES*; fuel costs *FCCAES* are given by combining the system heat rate *HRCAES* with the fuel (natural gas) price *cf* and the system energy yield for the entire system service period *nCAES*.

|  |  |
| --- | --- |
|  | (7) |

|  |  |
| --- | --- |
|  | (8) |

|  |  |
| --- | --- |
|  | (9) |

Table 1: PHS and CAES characteristics\*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Energy Storage Parameters** | | | | **Price Signals Range** | |
| **PHS Parameters** | **Value** | **CAES Parameters** | **Value** | **Parameter** | **Range** |
| cpump (€/kW) | 500 | ccomp (€/kW) | 400 | Nin (MW) | 20-300 |
| ct (€/kW) | 500 | cgt (€/kW) | 400 | Nout (MW) | 20-300 |
| cres (€/m3)\* | 15 | ccav (€/kWh)\*\* | 20 | Ess (MWh) | 100-3000 |
| mPHS | 5% | mCAES | 5% |  |  |
| nPHS (years) | 30 | nCAES (years) | 30 |  |  |
| HPHS (m) | 100 | HRCAES (kWhNG/kWhe) | 1.25 |  |  |
| ηin | 85% | cf (€/MWhNG) | 30 |  |  |
| ηout | 90% | ηin | 85% |  |  |
|  |  | ηout\*\*\* | 125% |  |  |

*\*The specific PHS and CAES cost values provided in the table assume inclusion of additional BOS components' costs, such as penstock and pipeline costs, transmission costs, grid connection costs, etc. In any case, the installation cost for both PHS and CAES much depends on the local site morphology and respective requirements; thus such values should be considered as extremely sensitive and treated accordingly*

*\*\*The specific cost values provided for energy storage capacity, consider also the system maximum depth of discharge*

*\*\*\*In a CAES plant, the electrical output is higher than the respective input (used to operate the compressor) due to the fact that fuel is also used to operate the gas turbine*

**4. Application Results**

First we present the results of time signal strategies, considering all five markets and the entire period of study, i.e. from 2007 to 2011. Accordingly, we perform exhaustive system operation simulations to capture the size variation of energy storage components for price signal strategies examined throughout the entire period of study and for all five markets. The results presented in the following sections are representative with an aim to evaluate the impact of different parameters on the value of arbitrage. Most importantly, we determine the optimum energy storage system size and configuration for each different electricity market and energy storage technology examined.

*4.1 Application of time signal strategies*

*4.1.1 Long-term time signal strategy*

The application of the long-term time signal strategy is based on the extraction of 4-year hourly average price curves on a daily and weekly basis for the five electricity markets examined. The results obtained by the analysis of the 4-year time series (see Figure 3 for daily average values, including 2011) are presented in Figure 4 and Table 2, with the corresponding curves and hours of minimum and maximum spot price. Greece and Spain follow an identical pattern. This is defined by two price peaks during the noon and night time, with the second one appearing to be comparatively higher. For northern areas, the second day peak appears earlier, during late afternoon hours, and is apart from the case of the UK found to be lower than the noon peak price. Moreover, Greece’s monopolistic market yields higher spot prices overall, while the mature and integrated market of Nord Pool presents the smallest price spread. The greatest spread is noted in the UK market (values given in £/MWh), reflecting the expensive operation of peak power plants in comparison to base load, but also in comparison to the rest of electricity markets investigated. In addition, significant contribution of RES in Spain is reflected in the lower spot price. In EEX the morning to mid-day market operation commands the second highest electricity prices. The observations of the weekly price curves are similar, with the minimum and maximum hour price concentrating during weekends and mid-week respectively with the exception of Spain (see also Table 2).





Figure 3: Time series of historical hourly spot electricity prices presented as daily averages for the electricity markets of (a) Nord Pool, UK and EEX and (b) Greece and Spain.





Figure 4: Long-term (4-year) daily and weekly average hourly electricity price pattern (2007-2010)

Table 2: Spot price time series analysis (2007-2010)

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Market** | **Week**  **Max** | **Price €/MWh** | **Daily**  **Max** | **Price €/MWh** | **Week**  **Min** | **Price**  **€/MWh** | **Daily**  **Min** | **Price €/MWh** |
| Nordpool | Monday-9:00 | 47.66 | 10:00 | 43.92 | Sunday-6:00 | 31.03 | 4:00 | 33.94 |
| UK | Tuesday-18:00 | 81.26 | 18:00 | 70.85 | Sunday-6:00 | 26.25 | 5:00 | 28.04 |
| Greece | Tuesday-20:00 | 75.31 | 21:00 | 72.17 | Friday-1:00 | 36.33 | 5:00 | 39.44 |
| EEX | Tuesday-12:00 | 75.11 | 12:00 | 65.44 | Sunday-7:00 | 12.75 | 4:00 | 25.46 |
| Spain | Sunday-22:00 | 59.77 | 22:00 | 55.38 | Friday-1:00 | 28.92 | 5:00 | 31.32 |

The *ARV* (arbitrage value) versus the system production cost for all markets is investigated for 2011 and the system operation is configured to permit additional energy purchase for 1 or 2 hours before and after the determined minimum price time point (Figure 5). Greece presents the highest *ARV* while Nord Pool presents the lowest that also becomes negative for PHS. More frequent system operation achieved by extending the system charging period has a slight negative impact on the *ARV* but reduces considerably the system production cost. Moreover, the weekly time scale produces higher *ARV* in all cases apart from Greece, although it also increases the system production cost to above €700/MWh.

Generally, except for the case of Nord Pool, the value of arbitrage compensates for the energy losses introduced by energy storage, producing net revenues ranging from €5-40/MWh. Furthermore, if adopting the daily time scale (which implies smaller storage capacity needs in comparison to a weekly time scale), the minimum system cost drops to almost €150/MWh which yields a net difference of €110-125/MWh. Overall, CAES outperforms PHS in terms of both *ARV* and *ND*, considering however that the obtained *ND* results are subject to the volatile price of natural gas used to operate the system (see also Table 1).





Figure 5: *ARV* vs system LC production cost based on the application of long-term time signals for PHS (a, b) and CAES (c, d) on a daily and weekly basis (*The ARV for the UK market is given in €/MWh and £/MWh, using the average annual exchange rate of each examined year*)

*4.1.2 Mirror time signal strategy*

The *ARV* deriving from the application of mirror arbitrage strategies is compared to the system production cost (Figure 6). In that case, the *ARV* presents considerable variation in the course of time for the markets of UK and EEX, owed mainly to the difference of the annual spot price (see Figure 3, where increase of prices during 2008 led to greater price spreads) and the greater consistency between mirror day and week time signals. On the contrary, fluctuation in the *ARV* in Greece and Spain is of narrow range, while Nord Pool presents negative values, apart from 2007-2008. Concerning 2010-2011, results obtained are similar to the ones deriving from long-term signals. In addition, CAES is again producing higher *ARV* that in the case of the UK (2007-2008) even exceeds €80/MWh.





Figure 6: *ARV* vs system LC production cost based on the application of "mirror" time signals for PHS (a, b) and CAES (c, d) systems on a daily and weekly basis (*The ARV for the UK market is given in €/MWh and £/MWh, using the average annual exchange rate of each examined year time*)

Overall, the examination of consecutive years reveals stable and unstable markets in terms of *ARV*, which can be associated with the respective fuel mix. Specifically, markets that are strongly dependent on fuel imports (such as UK and EEX) present considerable variation in electricity prices. This could lead to increased *ARV* for certain periods as a result of high fuel prices increase. Overall, minimum *ARV* in the order of €10/MWh should be expected for all cases examined, with daily system cycling suggesting production costs of €250/MWh and €200/MWh for PHS and CAES respectively.

*4.1.3 Back to back time signal strategy*

Intense variation of the *ARV* for the markets of UK and EEX is demonstrated when following back to back signal strategies (Figure 7). In this case, there is significant difference between the weekly and the daily time scale. Daily arbitrage values are similar to those of mirror signals with weekly ones being considerably higher. In fact, the weekly back to back strategy increases the *ARV* in all markets examined, producing a positive value even for Nord Pool. It is noteworthy that in certain markets and years, the *ARV* exceeds €80/MWh, reaching even €180/MWh for the UK in 2008. In this context, among the examined time signal strategies, the weekly back to back is the most effective in terms of *ARV*. As already described, in such a strategy the system is set to charge on a daily basis, adopting as a buying signal the hour of minimum price of the previous day, and discharge on a weekly basis, using as selling signal the hour of maximum price of the previous week. Operation of the system based on this strategy alone would not cover system costs that reach €900/MWh and €1200/MWh for PHS and CAES respectively. Instead, such a strategy enables the system to provide additional services, since the system output operates for only one hour per week. In conclusion, energy storage systems can exploit time signal based arbitrage under the condition that this comprises a complementary (secondary) source of revenue, maximized in the case of the weekly back to back strategy.





Figure 7: *ARV* vs system LC production cost based on the application of "back to back" time signals for PHS (a, b) and CAES (c, d) systems on a daily and weekly basis (*The ARV for the UK market is given in €/MWh and £/MWh, using the average annual exchange rate of each examined year*)

*4.2 Application of price signal strategies*

*4.2.1 The impact of applying different strategies*

The price signal strategies employed use static and moving-average approaches (Figures 8-13). System size in these cases is variable (see also Table 1), between 20MW-300MW for the input and output system power capacity and 100MWh-3GWh for energy storage capacity. Similar to other studies, upper values of input and output power capacity are constrained by the fact that the energy storage plant is assumed to be a price-taker, i.e. too small to influence electricity price during its operation, while assuming perfect next hour spot price prognosis. The impact of using different time-scales and strategies is studied for PHS, in the UK (2008), under a fixed, medium-large scale energy storage capacity of 1GWh (Figure 8).









Figure 8: Variation of the *ARV* and *ND* between the system production cost and the *ARV* from the application of different price signal based strategies (PHS, UK-2008)

At the same time, variation of the *ARV* and *ND* isprovided for different values of input and output power capacity (pumping station and hydro-turbine respectively). The use of different strategies and time-scales does not cause important *ARV* variation. Moreover, there is an area of output power capacity between Nt=50MW and Nt=150MW that gives the highest *ARV* for almost the entire range of input power capacity (i.e. the pumping power) and the given energy storage capacity of 1GWh. Furthermore, for the range of 100-140MW the higher the value of the output power capacity *Nt*, the higher the value of pumping power that gives the maximum *ARV*. Instead, *ND* tends to become higher for 20MW and 50MW as the pumping power increases beyond that same range of 100-140MW, with all other curves concentrated in the area of €20/MWh to €50/MWh. As a result, although the *ARV* is restricted below €30/MWh, *ND* is minimized, even reaching 20€/MWh. More frequent operation imposed to the system by the application of price signals is critical for the reduction of the system production cost, which also minimizes *ND*, despite the fact that *ARV* is lower (for this system size) than the one produced by time signal strategies for that particular market and year studied.

*4.2.2 The impact of system size*

Subsequently, the impact of energy storage capacity is studied for small, medium and large scale output power (i.e. Nt=20MW, Nt=150MW and Nt=300MW) in the EEX market (2009) using the weekly moving average strategy (Figure 9). To this end, the conclusion previously drawn concerning maximization of the *ARV* for output power capacity in the area of Nt=150MW is confirmed. More precisely, higher energy storage capacities yield higher *ARV*, except for Nt=20MW. In that case the small scale hydro-turbine of 20MW is unable to exploit the large energy storage capacity that encourages operation of pumping until it is completely charged (full). Furthermore, use of small-scale hydro turbines (Nt=20MW), although giving higher *ARV* for energy storage capacity below 500MWh, implies also higher *ND* for energy storage capacity above 500MWh and pumping power exceeding 50-60MW.







Figure 9: Variation of the *ARV* and *ND* between the system production cost and the *ARV* for low, medium and high capacity system output (PHS, EEX-2009)

*4.2.3 The impact of energy storage technology*

Comparison between PHS and CAES was performed for the Greek market (2010) where small and large-scale energy storage capacities were tested (Figure 10). As previously mentioned in the application of time signal strategies, CAES delivers higher *ARV*, which is confirmed for both the lower and the higher energy storage capacity studied, i.e. 100MWh and 3GWh. Net difference values of CAES and PHS on the contrary tend to become equal for the larger-size systems.









Figure 10: Variation of the *ARV* and *ND* between the system production cost and the *ARV* for small and large scale storage capacity (PHS-CAES, Greece-2010)

**5. Discussion**

Further elaboration of the application results obtained is undertaken in the current section together with their association with the different power markets examined, first aiming to evaluate the long-term value of arbitrage and secondly to designate optimum size dimensions for PHS and CAES based on the criteria of maximum *ARV* and minimum *ND*.

*5.1 The temporal impact and the long-term arbitrage value*

To account for the *ARV* and *ND* variation in the course of time, which could be thought representative of the risk taken by a potential investor, the UK market and weekly static average are used as example (Figure 11). Variation of the *ARV* and *ND* is represented by the vertical lines, with the average value for the 5-year period studied (2007-11) for both the maximum *ARV* and the minimum *ND* also provided. According to the figure, the maximum arbitrage value for the UK presents considerable variation in the course of time. Concerning the 5-year average values, increase of the selected energy storage capacity has a slight increasing effect on the *ARV*. Instead, in the case of the *ND*, a minimum appears in the area of 1000-1500MWh.





Figure 11: Variation of the maximum *ARV* and the minimum *ND* between system production cost and *ARV* (PHS-CAES, UK-2007-11)

Accordingly, the 5-year average values for the maximum *ARV* and the minimum *ND* are gathered in Figure 12, for daily static average and all electricity markets examined. The advantage of CAES over PHS concerning the *ARV* is clear for all markets, with Greece, EEX and UK producing the greatest value. On the contrary, *ND* results are in most cases comparable, with CAES proving more suitable for Greece, Nord Pool and for smaller energy storage capacity systems (in the order of 100MWh) and PHS presenting lower *ND* values for higher energy storage capacities. Moreover, although price signal based *ARV* fails to meet the value produced by time signal strategies, it implies high frequency operation which reduces the system production cost considerably. As a result, *ND* is minimized and even drops to €30/MWh (e.g. Greece).







Figure 12: Long-term maximum average *ARV* and long-term minimum average difference of system production cost and *ARV* for PHS and CAES configurations (all markets examined)

*5.2 Determination of optimum system dimensions*

Finally, in Figure 13, the respective optimum system dimensions are given. Daily static-average and all markets are examined, taking into account the average 5-year period values previously seen.More precisely, in the included charts, by selecting the value of energy storage capacity, the type of the energy storage system and an optimization criterion between maximum *ARV* and minimum *ND*, the recommended size for both input and output system size can be obtained. To this end, as energy storage capacity increases, Greece and Nord Pool require the greatest input power capacity, followed by UK and Spain. At the same time, EEX encourages operation of smaller-scale systems that do not exceed 100MW, similar to the case of the output power capacity, where CAES is in general encouraging operation of larger scale systems in comparison to PHS. Additionally, in the case of Spain, a maximum appears for both output and input capacity in the area of 1500MWh-2000MWh for both CAES and PHS. Finally, if examining the criterion of minimum *ND*, difference between markets is largely eliminated, with UK found to require the lower input and higher output power capacity.







Figure 13: Optimum input and output power capacity to achieve maximum *ARV* and minimum *ND* for both PHS and CAES systems (all markets examined)

**6. Conclusions**

By applying different energy trade strategies for a 5-year period in the markets of Nord Pool, EEX, UK, Spain and Greece, we estimated the value of arbitrage for PHS and CAES. Our results demonstrate that as European markets integrate and become more efficient, the value of arbitrage for energy storage is reduced. On the contrary, heavy reliance of markets on fuel imports (e.g. UK and EEX) create arbitrage opportunities from which a risk-adaptive investor could benefit. Arbitrage is also encouraged in less competitive markets such as the one of Greece, especially when indigenous energy reserves are used to cover base load and energy imports to cover peak load, creating thus a significant price spread. Looking how the presence of a dominant indigenous resource could impact on the arbitrage value of energy storage, arbitrage could also be looked further in markets where coal contributes in quite high ranges (e.g. China, Poland, etc. [51,52]). Presence of significant hydropower capacity on the contrary proves, as expected, to be a disincentive for energy storage, such as in the case of Nord Pool. Finally, for wind energy, the impact of intermittency and the requirement for greater flexibility is yet to be studied in terms of arbitrage, since no important evidence could be drawn from e.g. the case of Spain, where effective trading with Portugal, facilitates the presence of wind power.

Among the examined strategies, weekly back to back produces the highest arbitrage value; however, additional sources of revenue would be required to support the investment. At the same time, although requiring reliable prognosis of the next hours’ spot price, price signal strategies also produce a worthwhile arbitrage value that is found to maximize for different energy storage system size in each of the examined markets. In addition, the comparison between PHS and CAES reveals the advantage of CAES that nevertheless largely depends on the price of natural gas required for system operation.

Overall, despite the fact that our findings align with the common conclusion that arbitrage in itself cannot support investments in the energy storage sector, they also provide a set of directions on the optimum size and strategy for PHS and CAES practising arbitrage in electricity markets of different characteristics. In this way, development of innovative strategies that combine optimum arbitrage directions together with additional energy storage services such as RES support can be put forward, exploiting the potential of energy storage to perform different roles in an electricity market environment.

**Reference List**

1. Makansi J, Abboud J. Energy Storage-The Missing Link in the Electricity Value Chain. St Louis: Energy Storage Council; 2002.
2. Naish C, McCubbin I, Edberg O, Harfoot M. Outlook of Energy Storage Technologies. Brussels: European Parliament, Policy Department, Economic and Scientific Policy; 2008.
3. Zafirakis D, Chalvatzis KJ, Baiocchi G. Embodied CO2 emissions and cross-border electricity trade in Europe: Rebalancing burden sharing with energy storage. Appl Energ 2015; 143:283-300.
4. Solomon ΑΑ, Daniel M, Kammen D. Callaway The role of large-scale energy storage design and dispatch in the power grid: A study of very high grid penetration of variable renewable resources. Appl Energ 2014;134:75-89
5. Beaudin M, Zareipour H, Schellenberglabe A, Rosehart W. Energy storage for mitigating the variability of renewable electricity sources: An updated review. Energ Sust Dev 2010;14:302-14.
6. Kaldellis JK, Zafirakis D, Kavadias K. Techno-economic comparison of energy storage systems for island autonomous electrical networks. Renew Sust Energ Rev 2009;13:378-92.
7. Kaldellis JK, Zafirakis D. Optimum energy storage techniques for the improvement of renewable energy sources-based electricity generation economic efficiency. Energy 2007;32:2295-305.
8. Nyamdash B, Denny E, O’Malley M. The viability of balancing wind generation with large scale energy storage. Energ Policy 2010;38:7200-8.
9. Zafirakis D. Overview of energy storage technologies for renewable energy systems. In: Kaldellis JK, editor. Stand-alone and hybrid wind energy systems: Technology, energy storage and applications, Cambridge: Woodhead Publishing; 2010.
10. Katsaprakakis DA, Christakis DG. [Seawater pumped storage systems and offshore wind parks in islands with low onshore wind potential. A fundamental case study](http://www.sciencedirect.com/science/article/pii/S0360544214000280). Energy 2014;66:470-86.
11. Katsaprakakis DA, Christakis DG. [Maximisation of R.E.S. penetration in Greek insular isolated power systems with the introduction of pumped storage systems](http://www.scopus.com/record/display.url?eid=2-s2.0-84870030736&origin=resultslist&sort=plf-f&src=s&st1=Katsaprakakis&st2=&nlo=1&nlr=20&nls=count-f&sid=6A2781C7B660695075D1012F40D262CE.kqQeWtawXauCyC8ghhRGJg%3a63&sot=anl&sdt=aut&sl=47&s=AU-ID%28%22Katsaprakakis%2c+Dimitris+Al%22+22234374100%29&relpos=3&relpos=3&citeCnt=0&searchTerm=AU-ID%28%5C%26quot%3BKatsaprakakis%2C+Dimitris+Al%5C%26quot%3B+22234374100%29). In: European Wind Energy Conference and Exhibition 2009, 16-19 March 2009, Marseille-France.
12. Zafirakis D, Kaldellis JK. Economic evaluation of the dual mode CAES solution for increased wind energy contribution in autonomous island networks. Energ Policy 2009;37:1958-69.
13. Katsaprakakis DA. [Hybrid power plants in non-interconnected insular systems](http://www.sciencedirect.com/science/article/pii/S0306261915015354). Appl Energ 2016;164:268-83.
14. Katsaprakakis DA, Christakis DG. [A wind parks, pumped storage and diesel engines power system for the electric power production in Astypalaia](http://www.scopus.com/record/display.url?eid=2-s2.0-84876513345&origin=resultslist&sort=plf-f&src=s&st1=Katsaprakakis&st2=&nlo=1&nlr=20&nls=count-f&sid=0D6E76AE6C6597B7CC68B1892368D824.WXhD7YyTQ6A7Pvk9AlA%3a63&sot=anl&sdt=aut&sl=47&s=AU-ID%28%22Katsaprakakis%2c+Dimitris+Al%22+22234374100%29&relpos=8&relpos=8&citeCnt=4&searchTerm=AU-ID%28%5C%26quot%3BKatsaprakakis%2C+Dimitris+Al%5C%26quot%3B+22234374100%29). In: European Wind Energy Conference and Exhibition 2006, 27 February-2 March, Athens-Greece.
15. Sioshansi R. Increasing the Value of Wind with Energy Storage. Energ J 2011;32:1-30.
16. Zafirakis D, Chalvatzis KJ, Baiocchi G, Daskalakis G. Modeling of financial incentives for investments in energy storage systems that promote the large-scale integration of wind energy. Appl Energ 2013;105:138-54.
17. Zafirakis D, Chalvatzis KJ, Kaldellis JK. "Socially just" support mechanisms for the promotion of renewable energy sources in Greece. Renew Sust Energ Rev 2013; 21:478-93.
18. Drury E, Denholm P, Sioshansi R. The value of compressed air energy storage in energy and reserve markets. Energy 2011;36:4959-73.
19. Moreno R, Moreira R, Strbac G. A MILP model for optimising multi-service portfolios of distributed energy storage. Appl Energ 2015;137:554-66.
20. Kazempour J, Moghaddam MP, Haghifam MR, Yousefi GR. Risk-constrained dynamic self-scheduling of a pumped-storage plant in the energy and ancillary service markets. Energ Convers Manage 2009;50:1368-75.
21. Varkani AK, Daraeepour A, Monsef H. A new self-scheduling strategy for integrated operation of wind and pumped-storage power plants in power markets. Appl Energ 2011;88:5002-12.
22. Zafirakis D. Modern Energy Storage Applications. In: Yan J, editor. Handbook of Clean Energy Systems. Volume of Energy Storage, New Jersey: [John Wiley & Sons](http://eu.wiley.com/); 2015.
23. Connolly D, Lund H, Finn P, Mathiesen BV, Leahy M. Practical operation strategies for pumped hydroelectric energy storage (PHES) utilising electricity price arbitrage. Energ Policy 2011;39:4189-96.
24. McConnell D, Forcey T, Sandiford M. Estimating the value of electricity storage in an energy-only wholesale market. Appl Energ 2015;159:422-32.
25. Shcherbakova Α, Kleit Α, Cho J. The value of energy storage in South Korea’s electricity market: A Hotelling approach. Appl Energ 2014;125:93-102.
26. Walawalkar R, Apt J, Mancini R. Economics of electric energy storage for energy arbitrage and regulation in New York. Energ Policy 2007;35:2558-68.
27. Sioshansi R, Denholm P, Jenkin T, Weiss J. Estimating the value of electricity storage in PJM: Arbitrage and some welfare effects. Energ Econ 2009;31:269-77.
28. Sioshansi R. Welfare Impacts of Electricity Storage and the Implications of Ownership Structure. Energ J 2010;31:173-98.
29. Schill WP, Kemfert C. Modeling Strategic Electricity Storage: The Case of Pumped Hydro Storage in Germany. Energy J 2011;32:59-88.
30. Nord Pool. Nord Pool Power Data Services. <http://www.nordpoolspot.com/>; 2013 (accessed 15.05.2015)
31. Hellström J, Lundgren J, Yu H. [Why do electricity prices jump? Empirical evidence from the Nordic electricity market](http://www.sciencedirect.com/science/article/pii/S0140988312001429). Energ Econ 2012;34:1774-81.
32. Green R, Vasilakos N. Storing Wind for a Rainy Day: What Kind of Electricity Does Denmark Export? Energy J 2012;33:1-22.
33. Mauritzen J. Dead Battery? Wind Power, the Spot Market, and Hydropower Interaction in the Nordic Electricity Market. Energ J 2013;34:103123.
34. EEX. EEX Market Data – Power – Spot Market. <https://www.eex.com>; 2013 (accessed 15.05.2015).
35. UK APX. UKPX RPD Historical Data. <ftp://ftp.apxgroup.com/>; 2013 (accessed 15.05.2015).
36. Skea J, Chaudry M, Wang X. [The role of gas infrastructure in promoting UK energy security](http://www.sciencedirect.com/science/article/pii/S0301421511010639). Energ Policy 2012;43:202-13.
37. Chalvatzis KJ, Hooper E. Energy security vs. climate change: Theoretical framework development and experience in selected EU electricity markets. Renew Sust Energ Rev 2009; 13(9):2703-9.
38. Anderson KL, Mander SL, Bows A, Shackley S, Agnolucci P, Ekins P. [The Tyndall decarbonisation scenarios-Part II: Scenarios for a 60% CO2 reduction in the UK](http://www.sciencedirect.com/science/article/pii/S0301421508002875). Energ Policy 2008;36:3764-73.
39. Operador del Mercado Ibérico de Energía, Polo Español, S.A. (OMEL). Electricity Market. <http://www.omie.es>; 2013 (accessed 15.05.2015).
40. Amorim F, Vasconcelos J, Abreu IC, Silva PP, Martins V. How much room for a competitive electricity generation market in Portugal? Renew Sust Energ Rev 2013;18:103-18.
41. Garrués-Irurzun J, López-García S. Red Eléctrica de España S.A.: Instrument of regulation and liberalization of the Spanish electricity market (1944–2004). Renew Sust Energ Rev 2009;13:2061-9.
42. Cossent R, Gómez T, Olmos L. Large-scale integration of renewable and distributed generation of electricity in Spain: Current situation and future needs. Energ Policy 2011;39:8078-87.
43. Hellenic Independent Transmission System Operator (HITSO). Market Data-System Marginal Price. <http://www.admie.gr/>; 2013 (accessed 15.05.2015).
44. Eurostat. Market share of the largest generator in the electricity market. http://ec.europa.eu/eurostat/; 2013 (accessed 15.05.2015).
45. Navigant Research. Market Data: Advanced Batteries for Utility-Scale Energy Storage. https://www.navigantresearch.com/research/advanced-batteries-for-utility-scale-energy-storage/; 2016 (accessed 2/5/2016).
46. Deane JP, Ó Gallachóir BP, McKeogh EJ. Techno-economic review of existing and new pumped hydro energy storage plant. Renew Sust Energ Rev 2010;14:1293-302.
47. Bjarne S. Prospects for pumped-hydro storage in Germany. Energ Policy 2012;45: 420-9.
48. Energy Storage Association. Compressed Air Energy Storage (CAES). http://energystorage.org/compressed-air-energy-storage-caes/; 2016 (accessed 2/5/2016).
49. Lund H, Salgi G, Elmegaard B, Andersen AN. Optimal operation strategies of compressed air energy storage (CAES) on electricity spot markets with fluctuating prices. Appl Therm Eng 2009;29:799-806.
50. Zafirakis D, Chalvatzis KJ. Wind energy and natural gas-based energy storage to promote energy security and lower emissions in island regions. Fuel 2014;115:203-19.
51. Chalvatzis KJ. Electricity generation development of Eastern Europe: A carbon technology management case study for Poland. Renew Sust Energ Rev 2009; 13(6-7):1606-12.
52. Chalvatzis KJ, Rubel K. Electricity portfolio innovation for energy security: The case of carbon constrained China. Technol Forecast Soc 2015; 100:267-76.

Table 1: PHS and CAES characteristics\*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Energy Storage Parameters** | | | | **Price Signals Range** | |
| **PHS Parameters** | **Value** | **CAES Parameters** | **Value** | **Parameter** | **Range** |
| cpump (€/kW) | 500 | ccomp (€/kW) | 400 | Nin (MW) | 20-300 |
| ct (€/kW) | 500 | cgt (€/kW) | 400 | Nout (MW) | 20-300 |
| cres (€/m3)\* | 15 | ccav (€/kWh)\*\* | 20 | Ess (MWh) | 100-3000 |
| mPHS | 5% | mCAES | 5% |  |  |
| nPHS (years) | 30 | nCAES (years) | 30 |  |  |
| HPHS (m) | 100 | HRCAES (kWhNG/kWhe) | 1.25 |  |  |
| ηin | 85% | cf (€/MWhNG) | 30 |  |  |
| ηout | 90% | ηin | 85% |  |  |
|  |  | ηout\*\*\* | 125% |  |  |

*\*The specific PHS and CAES cost values provided in the table assume inclusion of additional BOS components' costs, such as penstock and pipeline costs, transmission costs, grid connection costs, etc. In any case, the installation cost for both PHS and CAES much depends on the local site morphology and respective requirements; thus such values should be considered as extremely sensitive and treated accordingly*

*\*\*The specific cost values provided for energy storage capacity, consider also the system maximum depth of discharge*

*\*\*\*In a CAES plant, the electrical output is higher than the respective input (used to operate the compressor) due to the fact that fuel is also used to operate the gas turbine*

Table 2: Spot price time series analysis (2007-2010)

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Market** | **Week**  **Max** | **Price €/MWh** | **Daily**  **Max** | **Price €/MWh** | **Week**  **Min** | **Price**  **€/MWh** | **Daily**  **Min** | **Price €/MWh** |
| Nordpool | Monday-9:00 | 47.66 | 10:00 | 43.92 | Sunday-6:00 | 31.03 | 4:00 | 33.94 |
| UK | Tuesday-18:00 | 81.26 | 18:00 | 70.85 | Sunday-6:00 | 26.25 | 5:00 | 28.04 |
| Greece | Tuesday-20:00 | 75.31 | 21:00 | 72.17 | Friday-1:00 | 36.33 | 5:00 | 39.44 |
| EEX | Tuesday-12:00 | 75.11 | 12:00 | 65.44 | Sunday-7:00 | 12.75 | 4:00 | 25.46 |
| Spain | Sunday-22:00 | 59.77 | 22:00 | 55.38 | Friday-1:00 | 28.92 | 5:00 | 31.32 |

**Figures’ List**

Figure 1: Long-term electricity supply fuel mix for the examined electricity markets

Figure 2: The methodology dimensions of the arbitrage problem under study

Figure 3: Time series of historical hourly spot electricity prices presented as daily averages for the electricity markets of (a) Nord Pool, UK and EEX and (b) Greece and Spain.

Figure 4: Long-term (4-year) daily and weekly average hourly electricity price pattern (2007-2010)

Figure 5: *ARV* vs system LC production cost based on the application of long-term time signals for PHS (a, b) and CAES (c, d) on a daily and weekly basis (*The ARV for the UK market is given in €/MWh and £/MWh, using the average annual exchange rate of each examined year* )

Figure 6: *ARV* vs system LC production cost based on the application of "mirror" time signals for PHS (a, b) and CAES (c, d) systems on a daily and weekly basis (*The ARV for the UK market is given in €/MWh and £/MWh, using the average annual exchange rate of each examined year time*)

Figure 7: *ARV* vs system LC production cost based on the application of "back to back" time signals for PHS (a, b) and CAES (c, d) systems on a daily and weekly basis (*The ARV for the UK market is given in €/MWh and £/MWh, using the average annual exchange rate of each examined year*)

Figure 8: Variation of the *ARV* and *ND* between the system production cost and the *ARV* from the application of different price signal based strategies (PHS, UK-2008)

Figure 9: Variation of the *ARV* and *ND* between the system production cost and the *ARV* for low, medium and high capacity system output (PHS, EEX-2009)

Figure 10: Variation of the *ARV* and *ND* between the system production cost and the *ARV* for small and large scale storage capacity (PHS-CAES, Greece-2010)

Figure 11: Variation of the maximum *ARV* and the minimum *ND* between system production cost and *ARV* (PHS-CAES, UK-2007-11)

Figure 12: Long-term maximum average *ARV* and long-term minimum average difference of system production cost and *ARV* for PHS and CAES configurations (all markets examined)

Figure 13: Optimum input and output power capacity to achieve maximum *ARV* and minimum *ND* for both PHS and CAES systems (all markets examined)

1. A price taker is an investor whose buying or selling transactions are assumed to have no effect on the market. [↑](#footnote-ref-1)