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Optimal management of a mega pumped hydro storage system under stochastic hourly electricity prices in the Iberian Peninsula

Luis M. Abadie [a], Nestor Goicoechea [b,*]

[a] Basque Centre for Climate Change (BC3), Sede Building 1, 1st floor, Scientific Campus, University of the Basque Country UPV/EHU, 48940, Leioa, Spain

[b] Escuela de Ingeniería de Bilbao, Universidad del País Vasco-Euskal Herriko Unibertsitatea (UPV-EHU), Ingeniero Torres Quevedo Plaza, 1, 48013, Bilbao, Bizkaia, Spain

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ABSTRACT

Concern for the environment led in some developed countries to planning future energy use that combines greater electrification with increasing use of Renewable Energy (RE) in the electricity generation mix. These scenarios can affect Security of Supply (SoS) because the intermittence of RE, its stochastic nature as an electricity generation sources and the demand's behaviour. It is necessary to increase storage capacity, among other measures. This paper analyses the effects of an optimal management strategy based on prices for Pumped Hydro Storage plants (PHES) using a daily mean reverting jump diffusion stochastic model of electricity prices in a risk neutral world including daily seasonality. Results show that a) income with this strategy under uncertainty may be insufficient compared to investment costs; b) the strategy does not usually provide proper guarantees as regards SoS at times of high demand for electricity; c) the technical characteristics of PHES such as the maximum upper & lower reservoir volume are highly significant. The effect of a minimum reservoir capacity at times of high demand is also analysed. PHES profitability can be improved under a Generating Company (GENCO) strategy coordinated with a wind farm and if the avoided CO_2 emissions are taken into account.

1. Introduction

The expected impacts of climate change on some countries have increased concerns about its effects. As a result, the countries that signed up to the 2015 Paris Climate Agreement [1] are planning to reduce their greenhouse gas emissions (GHG). In its Energy Roadmap 2050 [2], the European Union (EU) sets out a goal to cut greenhouse gas emissions by 80–95% by 2050, so there is a need for more energy efficiency and increases in renewable sources. Under to this roadmap, electricity production needs to be almost emission-free, despite higher demand.

Consequently a relevant response is to plan for future increases in the electrification of the economy (population growth, greater domestic electrification, transport electrification and others), an increase in electricity generation from Renewable Energy (RE) and a reduction in more polluting thermal power plants in the generation mix. These scenarios also assume that some nuclear power plants will close in the future on reaching the end of their useful lifetimes.

But RE technologies tend to behave intermittently, which may cause instability in future electricity transmission networks and affect security of supply (SoS) [3]. The European Commission has published standards for generation and system adequacy [4]. In this publication the European Commission selects Energy Not Supplied (EENS) as its preferred metric for assessing SoS.

To attain the goals of greater electrification with a high presence of RE electricity storage capacity needs to be increased. This paper looks at PHES power plants because the Global Status Report [5] states that the PHES is the main technology used for energy storage worldwide, with an installed capacity of 153 GW, accounting for 96% of the estimated total storage (rated power (GW)). PHES is a mature technology with long-term download capability that could be used to cover large mismatches between supply and demand, although sometimes this does not happen [6]. In addition, PHES is recognised to be the most sustainable energy storage technology [7].

This paper analyses the economic performance of a mega PHES plant in isolation, though PHES is a mature technology that can be used in combination with other renewable generation technologies such as wind and photovoltaic solar (PV), and also studies the

* Corresponding author.
E-mail address: nestor.goikoetxea@ehu.eus (N. Goicoechea).

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Nomenclature

Efi	Efficiency
€/MWh	Electricity price
m	Head
MW	Installed capacity
MW	PG Power generation mode
MW	PP Power pumping mode
m^3	Storage capacity
Hectares	Surface
MVA	Transformer electrical power
kV	Transformation ratio
m^3	Volume
m^3/h	WG Water flow in generation mode
m^3/h	WP Water flow in pumping mode

Deterministic Parameters

$\beta_1 - \beta_4$	Deterministic yearly seasonal parameters
β_5	Deterministic trend
β_6	Weekend and holidays parameter
β_7	Deterministic constant
$\beta_8 - \beta_{31}$	Deterministic hourly seasonal parameters

Stochastic Parameters

α	Numerator of long run mean (α/κ)
κ	Rate of reversion to mean
σ	Volatility mean-reverting part
μ_j	Mean jump
σ_j	Volatility jump
λ	Jump probability

Abbreviations

CAPM	Capital Asset Pricing Model
CSS	Clean Spark Spread
DCF	Discount Cash Flows
EENS	Energy Not Supplied
ESO	Electric System Operator
EU	European Union
GENCO	Generation Company
GHG	Greenhouse Gas Emissions
HPP	Hydro Power Plant
LSMC	Least Square Monte Carlo
NGCC	Natural Gas Combined Cycle
PHES	Pumped Hydro Storage Plant
PNIEC	Spanish's Integrated National Energy and Climate Plan
PSPP	Pumped Storage Power Plant
PV	Photovoltaic
RE	Renewable Energy
RO	Real Option
SoS	Security of Supply

effects of a management strategy for PHES plants, pumping when electricity prices are at or below one limit and generating electricity when prices are at or above another. The impact of a minimum reserve to be used in cases of high demand is also analysed. Both price limits are the result of an optimisation calculation under uncertainty where income is maximised. Technical aspects of the PHES plant, such as efficiency, installed capacity and reservoir volumes, are taken into account. To that end, a mean reverting jump diffusion stochastic model of electricity prices is estimated in a risk neutral world that includes daily seasonality.

PHES has high sunk costs, a long useful lifetime and some risks, such as electricity price risk and regulatory risks. These characteristics may discourage investment.

The paper is organised as follows: Section 2 reviews the literature, Section 3 describes the base case and a real case. Section 4 sets out the stochastic model of electricity prices and its calibration. Section 5 contains a Monte Carlo simulation of future electricity prices in both the real world and the risk neutral world. Section 6 presents the optimal control problem. Section 7 discusses the results and Section 8 concludes.

2. Literature review

To facilitate the transition away from fossil fuels towards cleaner energy many national climate and energy plans augur an increase of intermittent renewable energy in an effort to curb carbon emissions. Many researchers are analysing this fact from different perspectives. Lazkano et al. [8] study this shift in a top-down approach focussing on innovation and electricity storage. An overview of different technologies for storing energy can be found in Ref. [9]. Other papers study these challenges for the particularities of a certain region. This is the case of Sinn [10], who presents projections for Germany's green energy revolution and reviews the role of wind and solar plants and their volatility problem, Sinn presents the Norwegian hydro lakes as a solution to serve as buffers for German volatility. However, three constraints are reported: electricity transmission constraints, insufficient power in the Norwegian turbines and the impossibility of the hydro plants to go into reverse mode. In 2018, Zerrahn et al. [11] disagree with Sinn's approach and hold that the illustrations given are corner solutions. They conclude that even though electrical storage is important it is unlikely to limit the green energy revolution in Germany.

There are also studies that look at Portugal. Krajacic et al. [12] state that Portugal used to be a gas and oil importer: in 2006 it depended on imports for 86% of the country's requirements and only 14% of energy consumed was renewable. These authors study the technical and planning solutions for achieving 100% renewable energy production based on hourly energy balances, using H2RES software [13]. The target set in the Portuguese National Plan [14] of making 60% of the electricity system renewable by 2020 was exceeded, with 7000 MW of hydraulic capacity, 8500 MW of wind energy and 1500 of solar energy. In Ref. [15] notes the current status and insights gained from Portugal's experience in renewable energy development. The national energy policy strategies aimed at reducing energy dependence and carbon dioxide emissions have already produced good results: the installed capacity of the national power system for 2017 was approximately 19,884 MW, of which 7192 MW was hydropower, 5123 MW wind power, 2962 MW photovoltaic and 4607 MW gas fired generation. Islam et al. [16] address a techno economic optimisation of a zero-emission hydro energy system. In 2019, Figuerido et al. [17] study the decarbonisation of the Portuguese electricity system precisely by binding together the phase-out of all coal-fired power plants and its implications. The two plants in question, located in Sines and Pego, have a combined capacity of 1.7 GW, and their operating licenses expire in 2017 and 2021 respectively. The authors show that the switch results in 8 GW of PV plus 2.75 GW of PHES. Fortes et al., through the reference [18] analyse the decarbonisation in

Portugal and lead to the importance of the electrification, showing an increase of a small greenhouse emission target involves considerable increase of electricity price.

In an electricity market the balance between energy produced and consumed at a given time should be zero. Consumption is not constant and renewable energy generation is intermittent so in a 100% renewable scenario energy storage is essential for SoS. In that sense, a large-scale energy storage system has enormous potential globally. Gouveia et al. [19] analyse the effects of RE penetration of SoS in Portugal. In high peak demands, they observe electricity price increase due to taxes or weak storage infrastructure or lack of energy efficiency, in the other hand a good interconnection with Spain. Abbott and Cohen [20] highlight the importance in a market transition to design incentives and new policies to ensure SoS. However, a market based system increases uncertainties for investors [21]. In 2019, Yang et al. [22] evaluate the reliability of power systems in the presence of energy storage.

Menegaki [23] analyses the literature on the valuation of renewable energy projects that have utilised cost-benefit analysis, and acknowledges that this methodology is suitable for welfare economy oriented streams but for the case of energy economics that incorporate risk into resources there is a research gap that can be filled via Real Option theory (RO) and portfolio analysis.

Electricity consumption and price certainly follow a characteristic pattern. In Refs. [3,24] conduct empirical studies and confirm that the price pattern is one of high volatility, price jumps, seasonality and mean reversion. Davis and Owens [25] recognise that the value of RE projects can be enhanced by using RO theory, especially when advanced RO approaches are used. If a hypothetical hydropower plant is assessed initially using Discount Cash Flows (DCF), assessing the same project by RO methods can lead to a more precise assessment due to the option value of timing flexibility in operating the asset subject to market risk. Advanced RO utilises values for both flexible investment timing and decisions in operating parameters.

As mentioned, the real option methodology is able to value uncertainty and flexibility. Kozlova [26] summarises those two drivers for the case of renewable energy. For the case of PHES uncertainties recognises electricity price, demand, regulation and production. In 2020, Tian et al. [27] pay attention to market price uncertainty and relate it to financial risk. Flexibility appears in an option and in a PHES may differ depending on the stage of the project (planning or operational). In the planning stage the options may be timing or investing, while in the operational stage options may be stop, restart, switch regimes, continue, etc. Once the uncertainty is resolved the option is addressed. Alvarez [28] solves the problematic peak operation through a new mixed integer linear programming model.

There are publications on injection and withdrawal at natural gas storage facilities that consider a problem similar in some aspects to that of a PHES plant injecting and withdrawing water. Holland [29] uses Monte Carlo simulation with a Real Option (RO) approach to examine how to manage injection and withdrawal at a natural gas storage facility. Holland solves the optimisation issue by simulating each price path. Once the results of 300 simulations are obtained, the average is shown as the result. However, this approach implies perfect knowledge of future prices on each path, which implies an overestimation of storage value. Boogert and De Jong [30] use a Least Squares Monte Carlo method to value natural gas storage facilities considering both financial prices and physical aspects.

Muche, through the reference [31], develops a valuation model for pump storage plants using price simulation and including operational characteristics of plants. The present paper differs from that in the following aspects: a) a stochastic diffusion process with mean reversion and jumps in its stochastic part and seasonality, holidays and trend in its deterministic part has been utilised; b) that stochastic process is calibrated with historic real-world data; c) the stochastic process is converted into a risk-neutral process using futures quotes, which enables to use the riskless rate as the discount and thus avoid choosing a subjective discount rate (this issue is solved by Ref. [31] by using a Capital Asset Pricing Model (CAPM)); d) the current model optimally calculate two trigger prices that can easily be used in decision-making processes, and making sure that it is a global and not a local maximum; e) the sensitivity of some variables such as the reservoir volume in the plant valuation is analysed; f) finally, an economic impact when there is a minimum volume of water in the upper reservoir that is managed by the Electric System Operator (ESO) has been included and analysed, which enables to calculate the price of a reserve quantity with a view to guaranteeing SoS at times of peak demand.

3. Base case

PHES facilities usually have an efficiency level of 80–90% according to the Global Status Report [5]. However [32], report a range of 70–80% but also consider a case with 87%, and if evaporation losses and conversion losses are included approximately 70–85% of the electrical pumping energy used can be regained in the turbine.

Table 1 shows the parameters for the calculation in two cases, both with efficiency levels of or close to 80%. A theoretical base case is used to develop the methodology in a real case and the results allow the analysis of distinct behaviour of different PHES.

a) In the base case the parameters used are similar to those of [31].

70 MWh is used to upload 189,000 m^3 to the upper basin. This can generate (189,000*80)/270,000 = 56 MWh. Thus, the efficiency is $Efi = 56/70 = 0.80$. Using only MW the following is obtained: in pumping mode a maximum of 70 MWh is used, with 56 MWh being stored; in generation mode a maximum of 80 MWh is used, which is drawn from the upper basin; the upper basin has a maximum capacity of 1,890,000 * 80/270,000 = 560 MWh, which is equivalent to 560/80 = 7 h of full capacity operation.

This base case is used for sensitivity analysis, changing some parameters.

b) In the Gouváes case we use real parameters from a new PHES plant.

The Alto Tamega hydro power scheme is currently under construction in northern Portugal close to the city of Porto. The project is led by the Spanish energy company Iberdrola and the total installed mechanical capacity is 1158 MW, for average annual electricity generation of 1,766 GWh. Investment in this project is approximately €1,5 billion and it is expected to be operating by 2023 and to have an operational lifetime of 65 years. The scheme consists of two HPPs (hydro power plants) –Alto Tamega and Daivóes– and the Gouváes pumped storage power plant (PSPP). In this paper we focus on the Gouváes plant for two main reasons: i) it is going to produce most of the energy in the Alto Tamega System (1,468 GWh); and ii) it is a closed loop PHES.

The upper reservoir at Gouváes is natural. Its surface area is 176 ha and it has a volume of 13.7 hm^3. Through this natural reservoir passes the Torno river, whose flow-rate is minimal and negligible. In the hydroelectric calculations we also ignore the amount of water that can be evaporated and the amount of water that may be filtered through the phreatic layer. The lower reservoir is in Daivóes. It has to be constructed and its surface area is to be

Table 1
Pumping system parameters. Source: Base case [31] and Gouváes case [33].

Parameter	Base Case	Gouváes Case
Power pumping mode PP (MW)	70	880
Power generation mode PG (MW)	80	880
Water flow in pumping mode WP (m^3/h)	189,000	460,800
Water flow in generation mode WG (m^3/h)	270,000	576,000
Maximum water reservoir upper basin VW (m^3)	1,890,000	13,700,000
Minimum water reservoir upper basin VW (m^3)	0	0
Maximum water reservoir upper basin V_{max} (MWh)	560	20,930.5556
Minimum water reservoir upper basin V_{min} (MWh)	0	0
Efficiency (*Efi*)	0.80	0.80

341 ha. Its storage capacity will be 56.2 hm^3. In this facility the upper reservoir is therefore the bottleneck in terms of volume of water to be stored. The net head is about 650 m. The length of the circuit is 7670 m. The difference in altitude between the two reservoirs is 657 m and the system is to be equipped with four groups of Francis reversible pump-turbines and vertical axis motor-generators. The total capacity is 880 MW, with an annual production of 1468 GWh. The electrical system is to comprise four three-phase power transformers with a power of 245 Megavolt Amperes (MVA) and a transformation ratio of 400/15 kV (kV).

In this case, the PHES can generate 880 MWh using 576,000 m^3/h. The maximum capacity of the upper reservoir is 13,700,000 m^3, so if it is at its maximum capacity electricity can be generated for 13,700,000/576,000 = 23.7847 h, with a total output of 20,930.5556 MWh. This would be the maximum capacity in MWh. The minimum capacity is zero. 460,800 m^3/hour is pumped using 880 MWh, enabling (460,800/576,000) * 880 = 704 MWh to be generated at an efficiency of 704/880 = 0.80. Appendix B includes some hydraulic equations.

Regarding the efficiency of the PHES it depends on many conditions, length of waterways, operating points, length of grid connection, vaporisation losses, geometry of reservoir, etc. But as a rule of thumb the state of the art recognises a cycle circulating efficiency around 75–80%.

In 2021, Cavazzini et al. [34] realise a techno-economic analysis of pumped hydro combined with wind farms taking in account power reduction due to a numerical simulation of a pump-turbine transient load following process in pump mode based in Ref. [35]. The Gouváes plant's upstream and downstream reservoirs do not have significant water levels difference 7.78 and 9 m respectively compared to the gross head 660 m and the surge tank is designed to capture severe load cases in different working modes as it is confirmed in Gouváes hydraulic transient simulations [36]. For sure there are some small benefits in turbine partial load operation efficiency, but tenths of a percent and the mentioned figures are related to the optimum full load working point. Also, note that the proposed methodology can be used with different efficiency values depending on the technical characteristics of each pumped hydro storage system.

4. Stochastic model of electricity prices and their calibration

Electricity prices have seasonality, including hourly seasonality within each day, plus mean reversion, volatility and price spikes.

Through the reference [37] has been obtained daily Spanish electricity prices for 1461 days, corresponding to four years (from 2015 to 2018) and 35,064 hourly prices [37]. This Section calibrates a stochastic electricity model under the real-world probability measure P.

This work uses spot prices here because of the greater information that they provide and their liquidity, and assumes that there are no policies the part of the company that owns a portfolio of generation assets that would prevent the maximum profitability of the PHES plant because of decisions as to which assets generate electricity at any given time. It is also assumed that there are no grid congestions and that the PHES can pump or generate if conditions are favourable and all restrictions are met.

Fig. 1 shows the daily prices:

Stochastic models of electricity prices include those of [38–41]. This paper uses a modified version of the stochastic model described in Simulating Electricity Prices with Mean-Reversion and Jump-Diffusion [42].

The model describes the natural logarithm of spot prices p_t in Equation (1) as the sum of two components according to Ref. [43]. The first part $f(t)$ is deterministic and contains the variability (including annual, semi-annual and hourly seasonality) and the trend. The second part X_t is the mean reverting jump diffusion stochastic part.

$$\ln(p_t) = f(t) + X_t \tag{1}$$

$$\begin{aligned} f(t) = {} & \beta_1 \sin(2\pi t) + \beta_2 \cos(2\pi t) + \beta_3 \sin(4\pi t) + \beta_4 \cos(4\pi t) \\ & + \beta_5 t + \beta_6 D_t + \beta_7 + \sum_{i=8}^{31} \text{Unsupported}^{31} \beta_i H_{i-7,t} \end{aligned} \tag{2}$$

Equation (2) based on past studies by Ref. [43] describes the deterministic part of Equation (1) including annual, semi-annual and hourly seasonality. Equation (2) also includes the trend, a constant and a dummy variable D_t for weekends and public holidays. Only those official public holidays which apply to the whole of Spain and not regional holidays have been considered. $D_t = 1$ on weekends and holidays and $D_t = 0$ in other cases. The remaining 24 parameters correspond to the hourly seasonality. Calibrating the seven first parameters with daily prices gives the results shown in Table 2:

Fig. 2 shows the natural logarithm of electricity prices with their deterministic part. Fig. 3 shows the natural logarithm of electricity prices with the deterministic part removed.

Now, the model calculates the hourly seasonality using hourly prices for each day and comparing them with the daily price for the same day.

Fig. 4 refers to the calculated daily seasonality using all the time series and suggests that, all else being equal, the fourth and fifth hours are the most suitable for pumping and the twenty-first and 20-s are the most promising for generating electricity in a PHES plant. Table 3 shows the values calculated for hourly seasonality.

Equation (3) is the stochastic part of the logarithm of electricity prices [43]. This Equation (3) is an Ornstein-Uhlenbeck mean reverting model with jumps.

$$dX_t = (\alpha - \kappa X_t)dt + \sigma dW_t + J\left(\mu_j, \sigma_j\right)dq_t \tag{3}$$

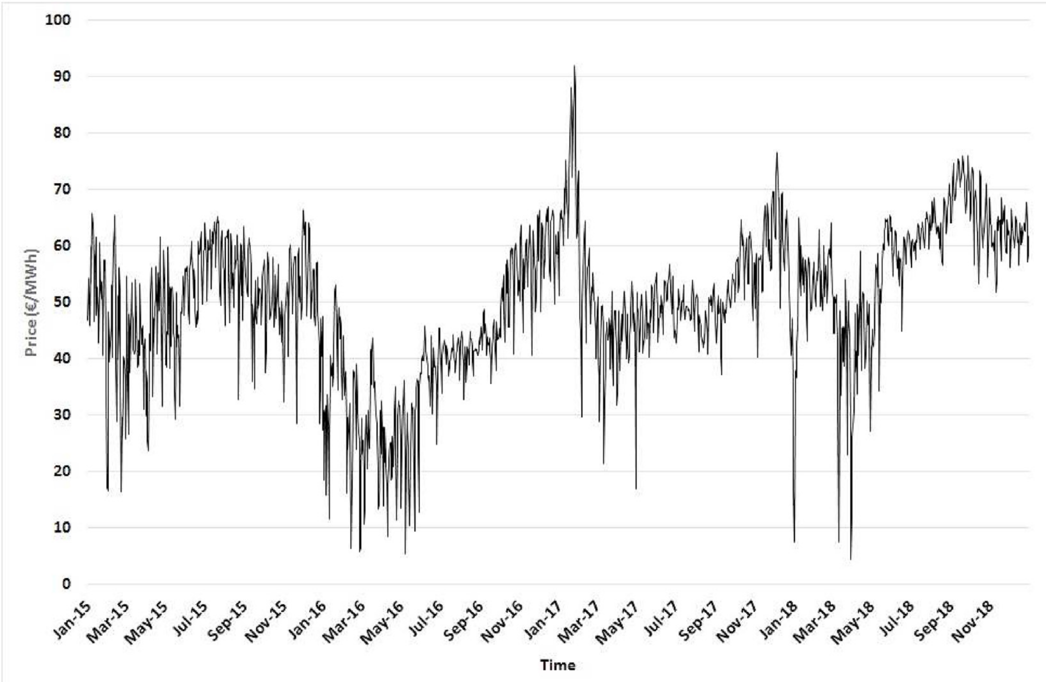

Fig. 1. Spanish daily electricity prices from 2015 to 2018. Source: prepared by authors using data from Ref. [37].

Table 2
Deterministic parameters calculated with daily prices. Source: author's own calculation.

Parameter	Value	Parameter	Value
β_1	−0.1808	β_5	0.0695
β_2	0.0302	β_6	−0.1881
β_3	−0.0213	β_7	3.7827
β_4	0.0919	–	–

In this equation the current logarithm of electricity price tends to level α/κ in the long term, with a reversion speed of κ. The volatility of the mean reverting process is σ. The third term of Equation (3) is a Poisson process with intensity λ. If there is a jump its size is normally distributed with mean μ_j and volatility σ_j. dW_t is the increment to a standard Wiener process and dq_t is a Poisson process such that $dq_t = 1$ with probability λdt and $dq_t = 0$ with probability $1 - \lambda dt$. dW_t and dq_t are independent.

Note that Equation (3) allows negative values, as the natural logarithm of some low electricity prices can be negative.

Using maximum likelihood estimation as described in Appendix A, the parameter values shown in Table 4 are obtained:

5. Monte Carlo simulation of the stochastic electricity price model

5.1. Electricity prices and Monte Carlo simulation under the real-world probability

First, it is necessary to simulate the stochastic daily part and then the deterministic daily part with the seasonality (annual and semi-annual), trend, weekend and holiday effect and a constant component must be included. Then the model converts the simulated daily series into hourly series by applying the daily seasonality to each daily logarithmic price simulated, obtaining 24 log prices for each day. Finally, the log prices are transformed into €/MWh prices.

The model runs 10,000 simulations for three years (2019, 2020 and 2021), i.e. 1096 days.

Fig. 5 shows the historic path and one simulated path of electricity daily log prices, including their deterministic part.

Fig. 6 shows the real stochastic path and one simulated path of daily log prices for electricity in €/MWh.

Fig. 7 shows the actual daily prices (2019–2021) and the mean of simulated for each day from the spot market in the Iberian Peninsula. Note that the expected values are the mean of each 10,000 daily simulated prices (that is the deterministic part), but each simulated path is volatile. In normal conditions the actual prices should correspond to a possible simulated path.

The sum of squares due to error (SSE) with 1096 observations is SSE = 454.52. Note that the period 2020–2021 is affected by the Covid-19 pandemic and its prices should not be used in a long-term assessment. Also in 2021, exceptionally, high natural gas prices have substantially affected electricity prices. These prices are not expected to be sustained in the long term.

5.2. The market price of risk and risk-neutral simulation

For risk-neutral valuation, the futures market price has been used as in Ref. [44]. As the riskless interest rate the long-term rate for German government bonds denominated in Euro in December 2018 is employed, which has r = 0.0019 [45].

To calculate the market price of risk the risk-neutral version of Equation (3) is utilised, i.e. Equation (4) adapted by author's from Equation (3) for risk neutral world.

$$dX_t = (\alpha - \kappa X_t - \sigma\xi e^{\beta t})dt + \sigma dW_t + J\left(\mu_j, \sigma_j\right)dq_t \quad (4)$$

where $\sigma\xi e^{\beta t}$ is the market price of risk, which is assumed to be increasing over time. Fig. 7 shows the expected value of the real world simulations and the futures quotes. The expected electricity price in the real world increases over time but the futures quotes decrease. Because of these behaviours a market price of risk that is

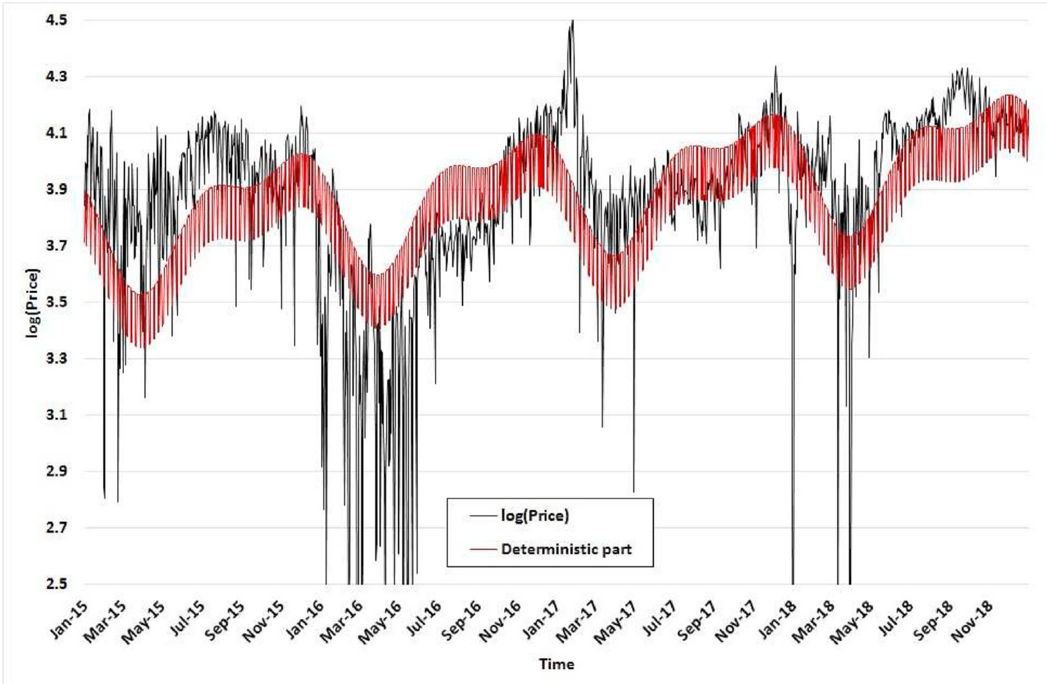

Fig. 2. Daily natural logarithm of Spanish electricity prices from 2015 to 2018 with their deterministic part. Source [37]: and author's own calculation.

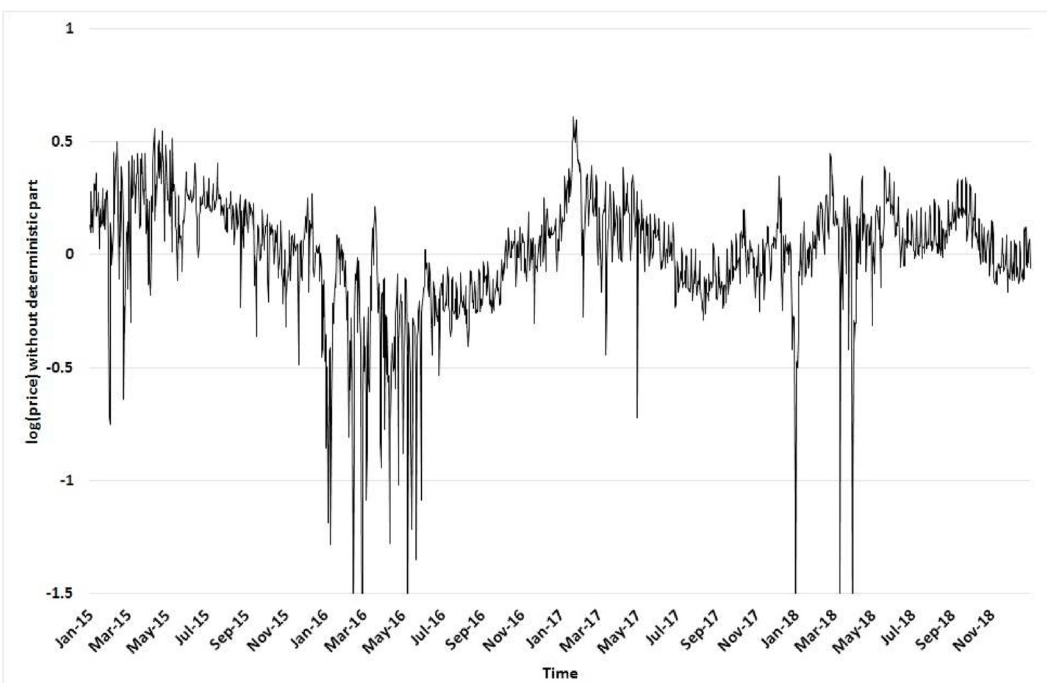

Fig. 3. Daily natural logarithm of Spanish electricity prices from 2015 to 2018 with their deterministic part removed. Source: author's own calculation.

increasing over time is selected.

When a simulation is run with Equation (4) and the deterministic part is incorporated, the result should be a daily simulation whose expected value should be compatible with the futures market quotes. Fig. 8 shows the 12/28/2018 quotes for Spanish baseload electricity futures [46], and the expected values of the real world simulation.

Using three years to calculate the market price of risk gives a present value of €1,475,980.95 for 1 MWh generated during all the hours of the three years. The expected value of the simulations discounted with the risk-free rate should be the same. As a second criterion, the parameters of the market price of risk should generate risk-neutral simulations whose expected values give a minimum squared error compared with the futures quotes. The

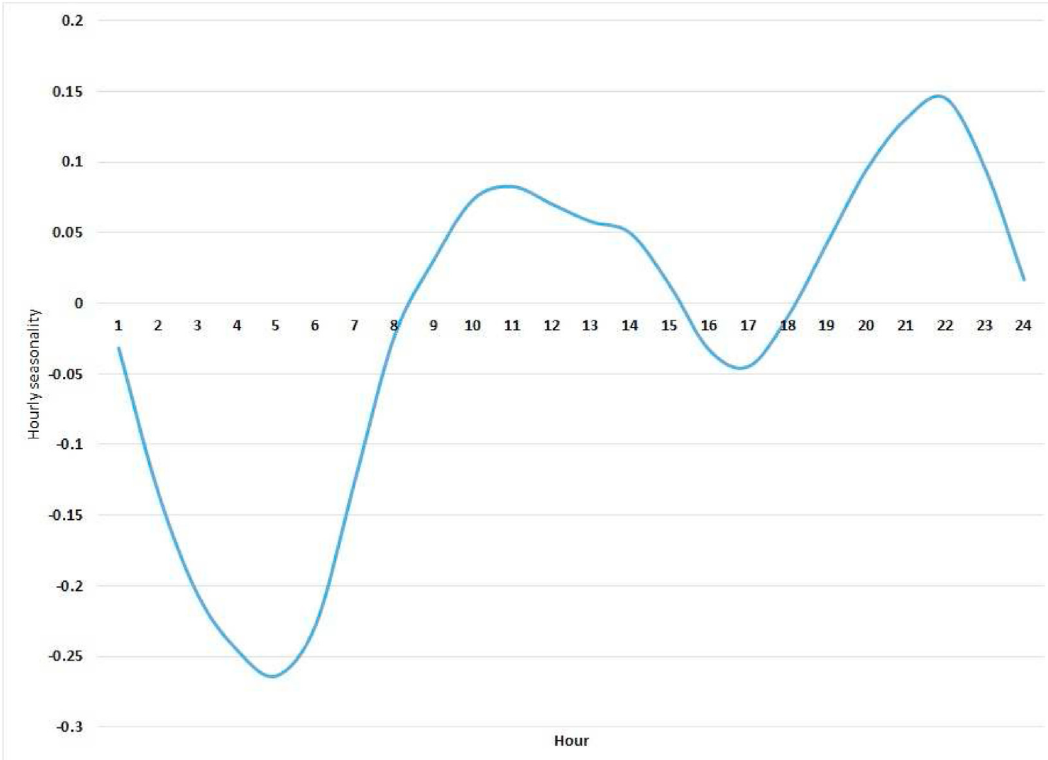

Fig. 4. Logarithm of electricity price hourly seasonality. Source: author's own calculation.

Table 3
Hourly seasonality. Source: author's own calculation.

Hour	seasonality	hour	seasonality	hour	seasonality
1	−0.0316	9	0.0303	17	−0.0448
2	−0.1335	10	0.0733	18	−0.0093
3	−0.2057	11	0.0827	19	0.0429
4	−0.2452	12	0.0703	20	0.0947
5	−0.2638	13	0.0577	21	0.1306
6	−0.2280	14	0.0496	22	0.1452
7	−0.1257	15	0.0127	23	0.0961
8	−0.0237	16	−0.0330	24	0.0168

Table 4
Parameters of the Stochastic Equation. Source: author's own calculation.

Parameter	Value	95% confidence interval
α	5.1435	2.8778−7.4093
κ	80.4557	66.7923−94.1191
σ	1.9052	1.7924−2.0116
μ_j	−0.1427	−0.2314−−0.0541
σ_j	0.4617	0.3860−0.5267
λ	36.3470	26.2827−46.4113

values resulting from the calculation are $\xi = 0.567$ and $\beta = 1.2$ with a minimum squared error of 84,860. Fig. 7 shows the expected values of the risk-neutral simulations and their fit with the futures quotes. Note that some futures quotes do not incorporate seasonality because they are mean values for certain periods. However, the risk-neutral simulation does incorporate seasonality.

The risk-neutral simulation gives valuations discounting the futures cash flow with the risk-free rate. Finally, the daily simulations have been transformed into hourly simulation using hourly seasonality.

6. The optimal control problem

This paper proposes a methodology based in a mean-reverting stochastic diffusion model with seasonality and trend. The parameters are calculated with actual daily prices and also include the confidence intervals. The selected model is suitable for valuation of derivatives on the electricity price and it can correctly represent the behaviour of hourly prices when they are very high or very low. Then the used stochastic model can be adequate for the valuation of a PHES plant that generates electricity when prices are high and pumps water when prices are low. This stochastic model can be recalculated when new information appears over time.

Using this stochastic model, the proposed methodology allows easily simulating a large number of equally likely paths of electricity prices; 10,000 in this work. First, the simulation is done in the real world, as usual for Value at risk (VaR) calculation. Second, an adjusted risk neutral simulation is done and used for valuation being the electricity paths, in this case, consistent with electricity futures market prices. As usual in derivatives valuation, with this risk neutral simulation the income can be discounted with the risk-free rate.

For each pair of values of the generation and pumping limits, the economic results can be calculated and a global maximum of these can be obtained for the optimal bidding strategy. The proposed

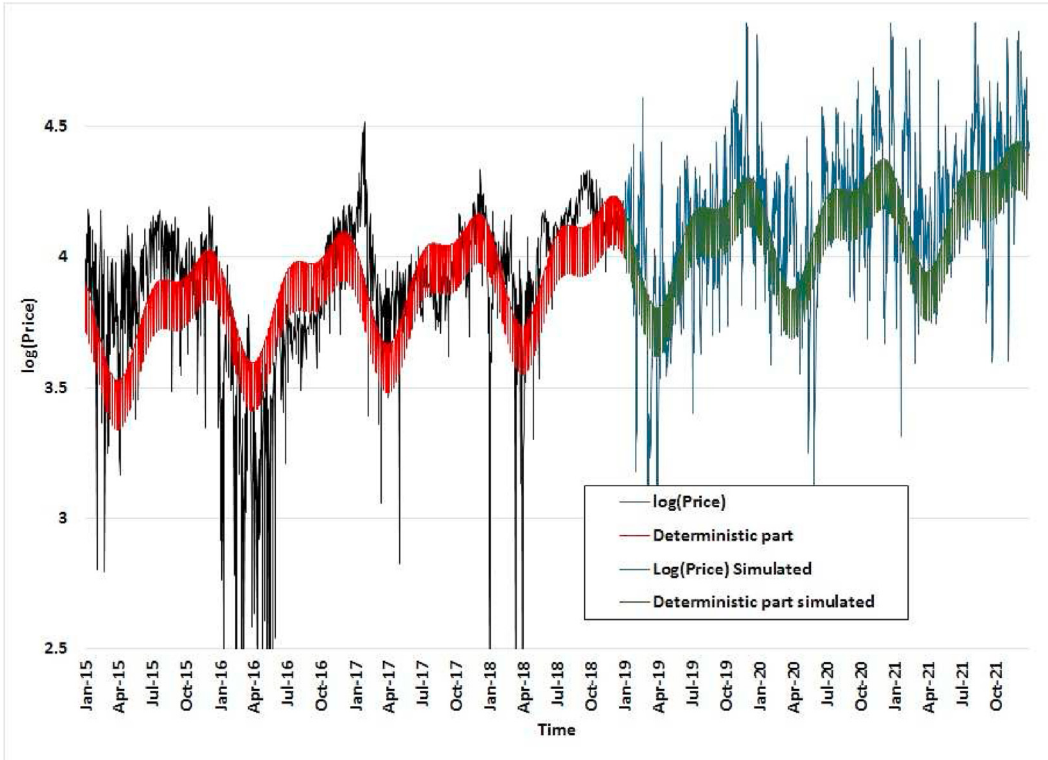

Fig. 5. Historic log prices and one simulated path of electricity daily prices. Source: author's own calculation based on [37].

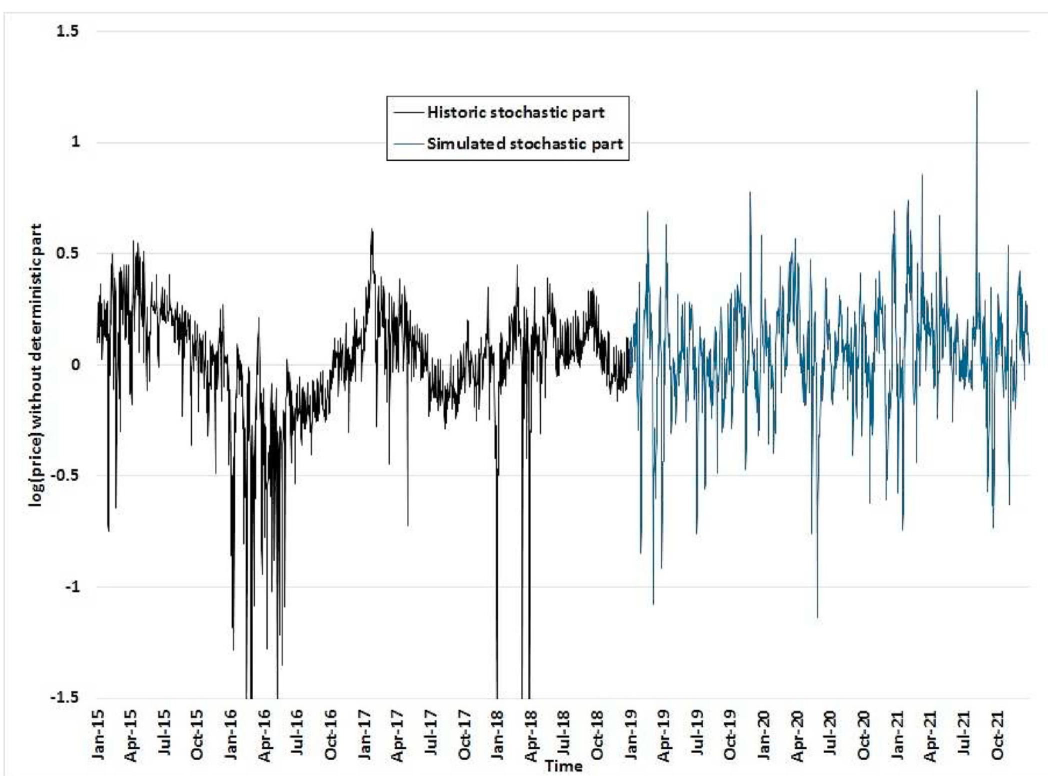

Fig. 6. Historic stochastic part of log prices and one simulated stochastic path of electricity daily prices. Source: author's own calculation based on [37].

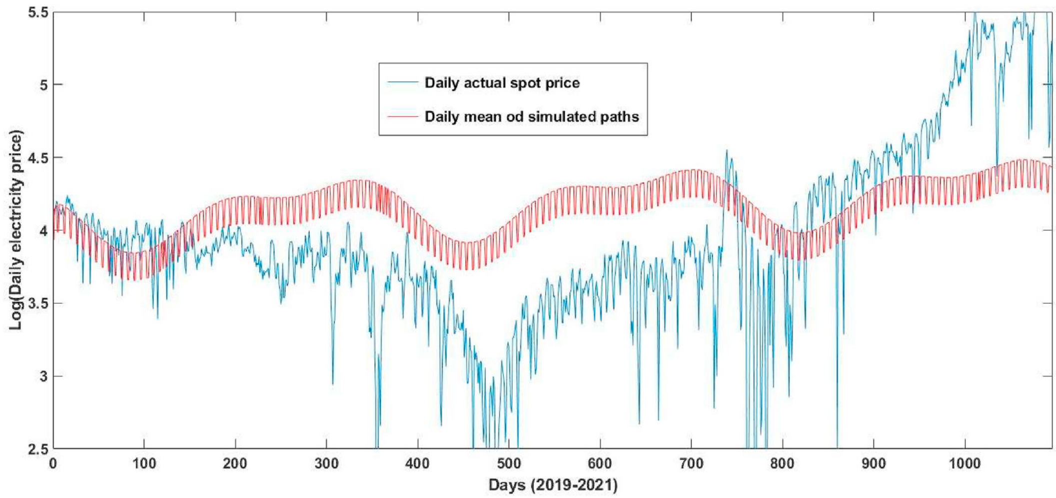

Fig. 7. Comparison between simulated and actual electricity prices (2019–2020). Source: prepared by the authors using data from Ref. [37] and author's own calculation.

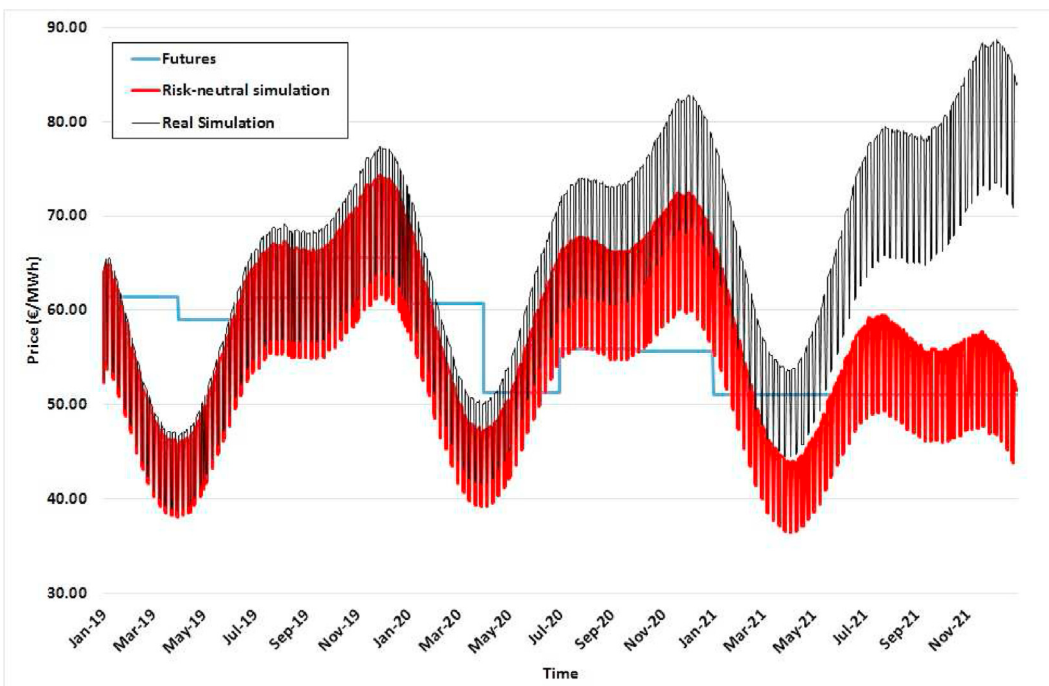

Fig. 8. Spanish baseload futures quotes 12/28/2018 Source [46]: and expected values of the real world simulation and compatible expected values of the risk-neutral simulation Source: author's own calculation.

methodology can be used depending on the time horizon for a long-term valuation or a short-term strategy. The paper also incorporates the results of a Generation Company (GENCO) when the PHES is coordinated with a wind farm and calculates the avoided CO_2 emissions.

The complete flowchart of the model indicating all steps for analyses is in Fig. 9.

There are three possible actions at each time: pump, generate electricity and do nothing. It has been assumed an optimal management strategy π such that

if $p_{t_i} \geq p^{\text{sup}}$ then $d^{g}_{t_i} = 1$.

if $p_{t_i} < p^{\text{sup}}$ then $d^{g}_{t_i} = 0$.

if. $p_{t_i} \leq p^{\text{inf}}$ then $d^{p}_{t_i} = 1$

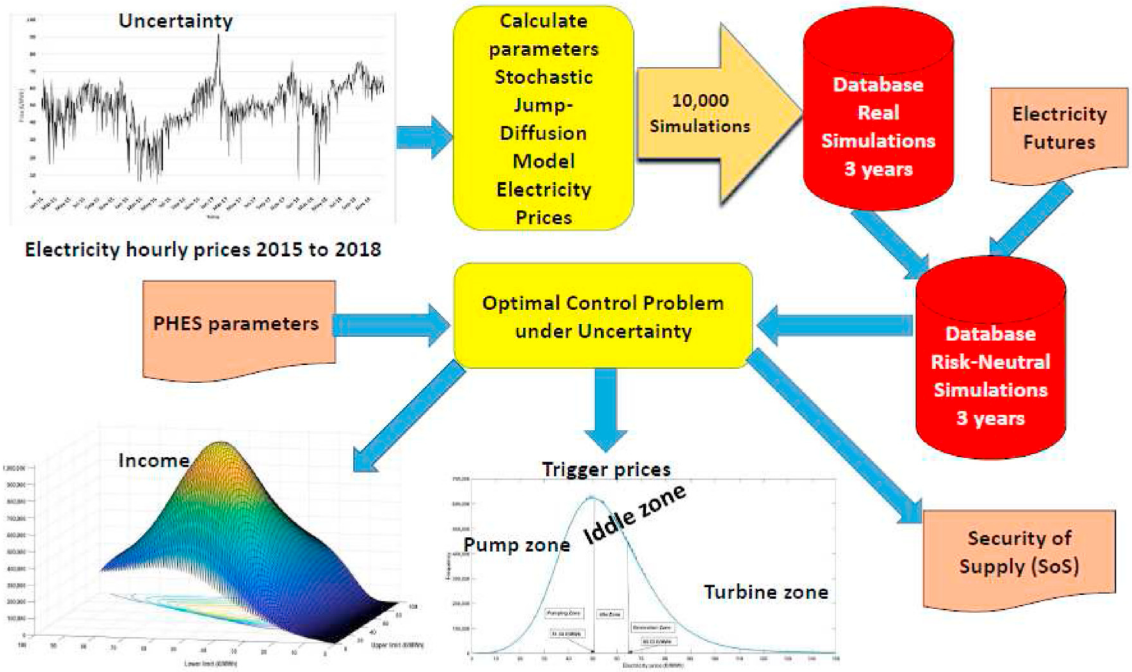

Fig. 9. Flow chart of the model. Source: Author's own model.

If. $p_{t_i} > p^{\inf}$ then $d^p_{t_i} = 0$

Always. $d^g_{t_i} + d^p_{t_i} \leq 1$

Equation (5) shows the function to be maximised, author's own designed Equation for this work.

$$\sup_{\pi} E\left[\sum_{i=1}^{i=N} \text{Unsupported}\rceil p_{t_i}\left(d^g_{t_i} MPG_{t_i} - d^p_{t_i} MPP_{t_i}\right)e^{-\frac{rt_i}{365x24}} + p_{t_N}(V_{t_N} - V_0)e^{-\frac{rt_N}{365x24}}\right] \tag{5}$$

There are N periods, p_{t_i} is the electricity price at time t_i, that is the time of period i, MPG_{t_i} is the maximum generation in period i, MPP_{t_i} is the maximum pumped in period i, r is the risk-free interest rate, V_0 is the initial reservoir volume, V_{t_N} is the final reservoir volume. Reservoir volumes are measured in MWh based on their ability to generate electricity when in generating mode.

If the final volume is different from the initial one there is a benefit or a penalty.

$$V_{\min} \leq V_{t_i} \leq V_{\max} \tag{6}$$

As shown in Equation (6), author's own designed Equation for this work, it is not possible to pump an amount which, added to previous volume, exceeds the maximum capacity of the reservoir. Also, there are limits in pumping and generation modes. Nor is it possible to generate an amount that exceeds its actual volume. So, restrictions refer to the operation of the PHES such as maximum and minimum volume management. Because of these facts, the following conditions apply:

$MPG_{t_i} = \min(PG, V_{t_{i-1}} - V_{\min})$; $MPP_{t_i} = \min(Efi \times PP, V_{\max} - V_{t_{i-1}})$Where Efi is the efficiency.

The reservoir volume changes according to Equation (7), author's own designed Equation for this work:

$$V_{t_i} = V_{t_{i-1}} - MPG_{t_i} d^g_{t_i} + MPP_{t_i} d^p_{t_i} \tag{7}$$

It is not considered the possibility of status changes at intervals of less than 1 h.

In 2001, Longstaff and Schwartz [47] propose using only in-the-money paths for valuing American options with their method, called Least Square Monte Carlo (LSMC), but [30] state that this recommendation cannot be used in a storage valuation because there are negative payoffs during the injection phases. The same applies to pumped phases in a pure PHES facility.

The method follows a different approach based on Monte Carlo simulation as described below.

7. Results

7.1. Base case results

It has been simulated 10,000 paths, each with 26,304 hourly prices, making a total of 263,040,000 hourly prices. These results are equivalent to the rental value of a PHES for 3 years. However, they can be extrapolated to estimate the profitability of the PHES over its whole useful lifetime. Using the Equation in Section 5 and r = 0.0019, a maximum income with $p^{\inf} = €51.54/MWh$ and $p^{\sup} = €65.53/MWh$ is obtained. With these values the expected income is €1,017,612. The investment cost of a PHES plant depends on factors such as geology, topography [48] and country, and in

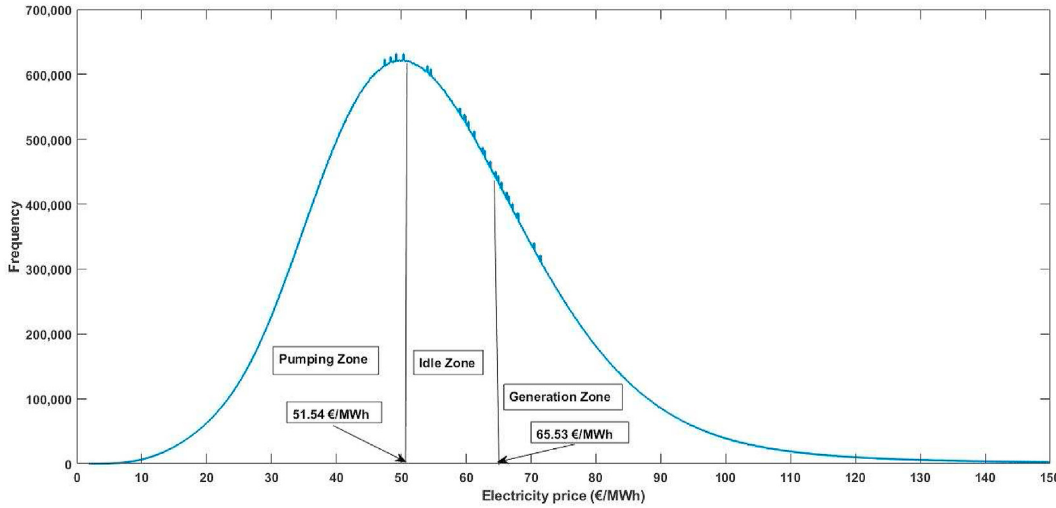

Fig. 10. Histogram of hourly electricity prices. Source: author's own calculation.

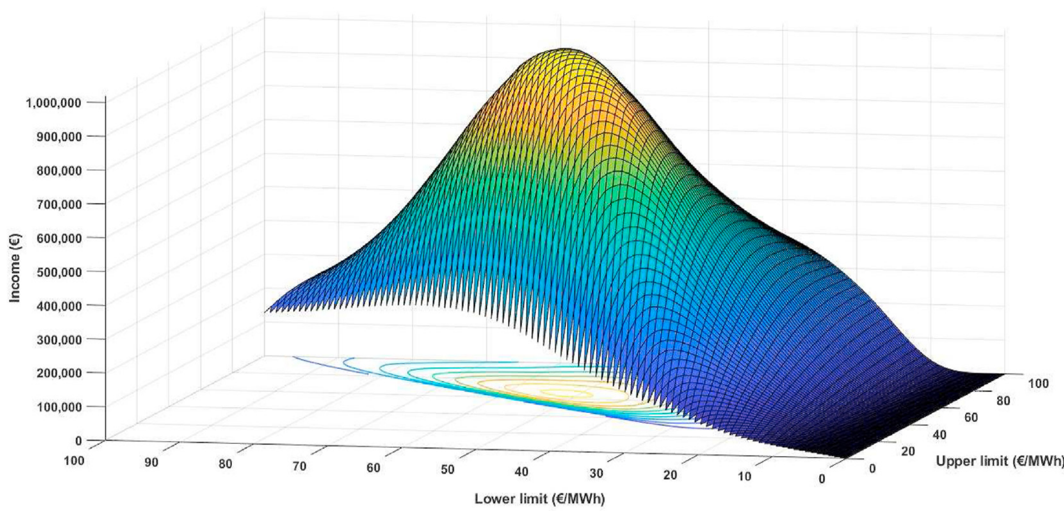

Fig. 11. Income as a function of lower and upper limits. Source: author's own calculation.

Table 5
Optimisation results. Source: author's own calculation.

Mode	Pumping	Generating
Limit	€51.54/MWh	€65.53/MWh
Mean	€39.91/MWh	€80.75/MWh
% cases	45.63%	25.69%

Table 6
Upper reservoir size sensitivity. Source: author's own calculation.

Size	Pumping Limit	Generating Limit	Income (€)	% Generating
560 MWh	€51.54/MWh	€65.53/MWh	1,017,612	3.68%
5600 MWh	€52,14/MWh	€66.88/MWh	4,903,690	9.85%
56,000 MWh	€49.02/MWh	€66.76/MWh	11,341,534	16.63%

some cases can approach €1000/kW [6]. In the base case this means €80 million. This investment cost distributed over its useful lifetime is greater than the income calculated for this new PHES plant.

Fig. 10 shows the histogram of hourly electricity prices and the three zones: pumping, idle and generating.

Table 7
Impact of upper reservoir size on generation at times of high demand. Source: author's own calculation.

Size	Number of cases with generation
560 MWh	695
5600 MWh	22,571
56,000 MWh	55,456

Here can be found the strategic decision which lies in three options a lower limit strategy consists in pumping when $p_{t_i} \leq €51.54$/MWh, an upper limit strategy consists in generating electricity when $p_{t_i} \geq €65.53/MWh$ and the third being idle in the remaining cases, but it is necessary to comply with the restrictions.

The maximum income result can be checked in Fig. 11:

With the limits shown in Table 5, when the PHES is in generating mode a mean price of €80.75/MWh is achieved and when it is in pumping mode a mean price of €39.91/MWh is paid. However, restrictions play an important role in this model. Without restrictions electricity would be generated in 25.69% of cases, and those cases would coincide with the times of higher prices, which are usually those of greatest demand. Note that restrictions and uncertainty play an important role in the decision process. According to our calculations with restrictions such as volume limitations and with uncertainty electricity is expected to be generated in a PHES plant in only 3.68% of cases.

7.1.1. Sensitivity analysis of the base case

The first question is what impact the upper reservoir size has. Table 6 shows the results for this.

Table 6 shows that with a larger upper reservoir the effect of the restrictions is reduced and more income is made. These results highlight the importance of choosing a suitable location for investing in a PHES facility. Table 6 also shows the impact of the upper reservoir size in terms of the proportion of time spent generating. With an upper reservoir size of 56,000 MWh the PHES plant is generating electricity for 16.63% of the time. However, uncertainty, the need for lower electricity prices and physical reservoir limitations mean that the theoretical maximum of 25.69% of the time cannot be reached.

A second issue is whether the PHES facility contributes significantly to Security of Supply (SoS). Data is 10,000 simulation paths with 26,304 prices each. The 9 highest values from each three-year simulation are extracted, i.e., the work has 90,000 simulations of extreme demand conditions using the price limits in Table 5. An analysis of their electricity power generation give the results shown in Table 7.

PHES operation under uncertainty causes low use for SoS contribution if the upper reservoir is small. Only with a large upper reservoir can PHES plants be expected to make a significant contribution in extreme demand conditions.

These results derive from the restrictions and from operation under uncertainty.

February 2019 saw the presentation in Spain of the draft of the country's Integrated National Energy and Climate Plan [49]. In this draft there is a projection for increasing the installed capacity of pure PHES by 3.5 GW by 2030. The PNIEC considers that there will be regulatory changes for PHES operation because of the need for greater integration of renewable generation technologies into the grid, and believes that those changes will be managed by the system grid operator [50]. These calculations suggest that an adequate SoS goal cannot be achieved efficiently with a pricing strategy such as the one studied in this paper: it seems necessary to have a reserve capacity that is really available at times of maximum demand as analysed below.

Other questions that must be considered include how PHES plants really perform in maximum demand hours and whether the obtained results are consistent with real behaviour in recent years. To analyse this it is considered 35,064 samples of hourly data for the period 2015–2018 for demand, installed capacity and net PHES generation in the Spanish electricity system. Using information on the 12 maximum hourly demand periods (three per year) it is found that only 36,03% of the installed capacity is used at those times. Fig. 12 shows the real behaviour of PHES plants (% use of installed capacity) in Spain as a function of hourly demand in the period 2015–2018. It can be seen that only at few times do these plants generate a high percentage of their installed capacity, also at times of high demand.

These results are in line with those of [51]. These authors say that generators are usually conservative and tend to opt to use some water resources when prices are moderately high instead of waiting for a possible but uncertain peak price in the future.

7.1.2. Valuation with a minimum volume of capacity dedicated to security of supply (SoS)

As can be seen the policy of maximum earning from PHES plants does not guarantee adequate coverage of security of supply at times of maximum demand. Now it is analysed the effect on PHES plant income of considering a minimum volume used in cases of extreme prices. We use the 99th percentile with a value of €115.8904/MWh. Assumption is a reserve capacity of 25%, i.e. 140 MWh. The behaviour is as follows:

a) When prices are below €115.8904/MWh the PHES plant behaves as in the base case, but the reserve capacity cannot be used.
b) When the prices are €115.8904/MWh or more the maximum possible electricity is generated, using the reserve capacity if necessary. The corresponding revenue is received by the owners

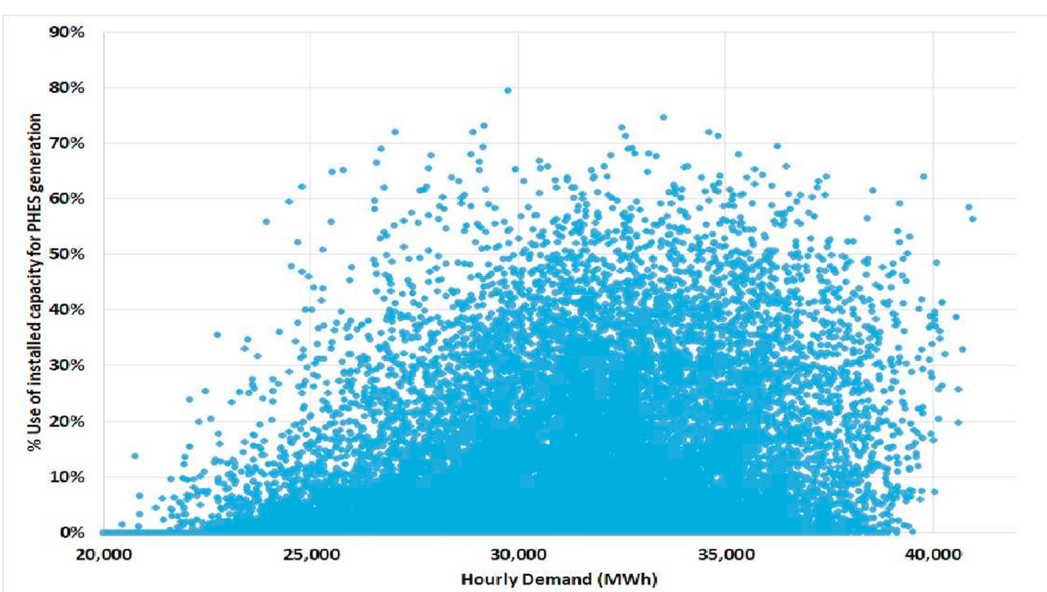

Fig. 12. Use of PHES plants in generation mode as a function of demand. Source: prepared by authors using data from Ref. [37].

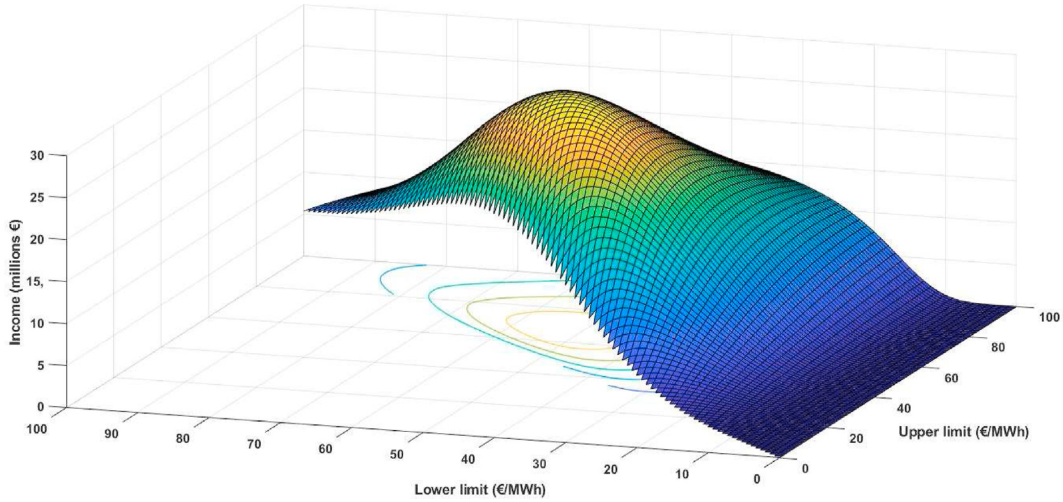

Fig. 13. Results for the Gouváes case. Source: author's own calculation. The PHES plant generates electricity for 6.50% of the total hours and 9.65% of the high demand hours.

of the PHES plant. Note that if the reserve capacity is below the minimum it must be restored by pumping at times of low prices.

These calculations show that the optimal trigger prices are €53.86/MWh for pumping and €64.61/MWh for generating. The income expected is €921,415, i.e. 9.45% less than in the base case.

All that shows that it is possible to dedicate a minimum reservoir capacity to Security of Supply (SoS) with a relatively low financial loss that can be offset by the Electricity System Operator (ESO).

7.2. Gouváes case results

In this case the obtained results are $p^{\inf} = €51.59/MWh$ and $p^{\sup} = €66.51/MWh$., With these values the expected income is €28,653,420. Fig. 13 shows these results.

7.3. Generation company strategy

The Generation Companies (GENCOs) usually own a diversified portfolio including wind farm, PHES, and thermal units [52]. This Subsection performs a sensitivity analysis for the optimal bidding strategy for GENCO related to the integration and coordination of these generation power plants, evaluating how a GENCO strategy can affect to calculations incorporating some aspect of coordination into the proposed model, the results depend on the specific possibilities of each GENCO.

7.3.1. The case of a generation company (GENCO) with PHES and wind farms

In this case the PHES has a maximum use of 560 MWh reservoir capacity and a maximum of 70 MW in pumping mode. Now it is assumed that the PHES can be combined with an electricity supply from the wind farms up a maximum of 35 MWh, this assumption is equivalent to a coordination with a wind farm of 280 MW installed capacity and a capacity factor of 25% when 50% of its generation can be used in the PHES power plant. It is assumed that a quantity Q can be obtained without cost when electricity price is low according to author's developed Equation (8).

$$Q(p_t) = \gamma_1 + \gamma_2 p_t \text{ } if \text{ } p_{min} \le p_t \le p_{max}$$

$$Q(p_t) = 0 \text{ } if \text{ } p_t > p_{max} \tag{8}$$

$$Q(p_t) = 35 \text{ } if \text{ } p_t < p_{min}$$

where p_t are the simulated electricity prices, $p_{min} = 1.8458€/MWh$ is the minimum of simulated electricity prices and $p_{max} = 55.6186€/MWh$ is the mean of simulated electricity prices of the time series. The PHES obtains 35 MWh without cost when the prices are very low ($p_{min} = 1.8458 \text{ €}/MWh$) and the shared amount decreases for higher prices and being null for prices higher than the average. The Equation (8) assumes a lineal decreasing relation between the excess of available production in the wind farm and the market electricity price, where the prices are positively correlated with demand.

Then, it is assumed that the price in pumping mode (p_w) behaves according to Equation (9), author's developed Equation.

$$Q(p_t) = 36.2014 - 0.6509 p_t \text{ } if \text{ } p_{min} \le p_t \le p_{max}$$

$$Q(p_t) = 0 \text{ } if \text{ } p_t > p_{max} \tag{9}$$

$$Q(p_t) = 35 \text{ } if \text{ } p_t < p_{min}$$

And the price paid in pumping mode p_w is according to Equation (10), author's developed Equation.

$$p_w = p_t \frac{70 - Q(p_t)}{70} \text{ } if \text{ } p_{min} \le p_t \le p_{max}$$

$$p_w = p_t \text{ } if \text{ } p_t > p_{max} \tag{10}$$

$$p_w = 0.50 p_t \text{ } if \text{ } p_t < p_{min}$$

This Function is shown in Fig. 14:

Now the simulated prices p_w are easily obtained using the p_t prices and the Equations (9) and (10). Those p_w prices can be used in an economic valuation of the PHES plant coordinated with the wind farm.

Using this information and the proposed methodology a global optimum is obtained with p_w lower limit of 45.47 €/MWh and an upper limit of 55.31 €/MWh. These mean prices for the PHES plant occur when the market prices are 48.63 €/MWh and 55.41 €/MWh respectively, these values can be obtained using the Equations (9)

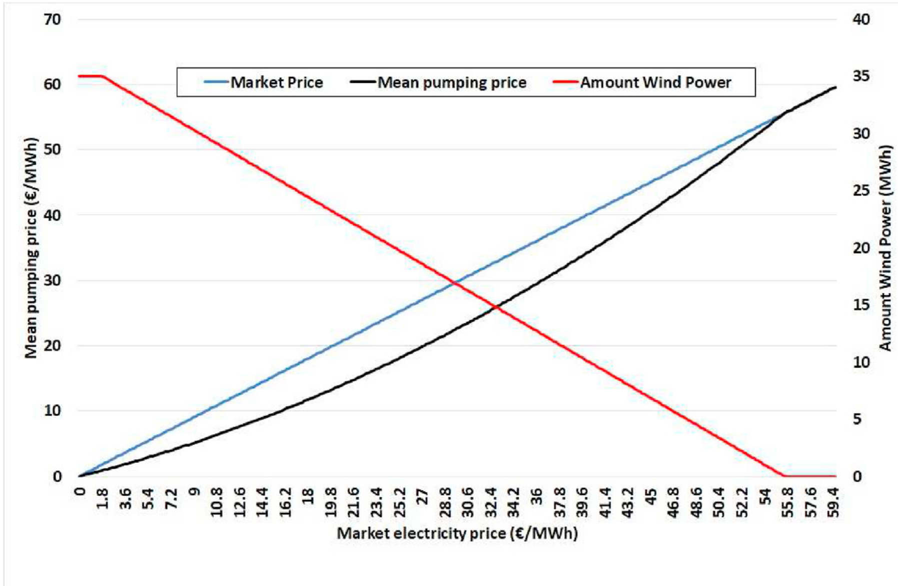

Fig. 14. Mean pumping price when GENCO strategy applies. Source: author's own calculation.

Table 8
Actual and future targets of installed power capacity.

Technology (MW)	Actual Source [50]:	PNIEC Source [49]:	
	2021	2025	2030
Coal fired	3523	2165	0
Natural gas combined cycle	24.562	26,612	26,612

and (10) as it is said.

In this case the expected income is 1,588,272 €, that is 56.1% more than the 1,017,612 of Table 6. This result is obtained using 119,541 MWh from the wind power plant.

7.3.2. CO_2 emission avoidance due to PHES and wind energy coordination

The installed power capacity of thermal power plants in the Spanish electricity system at the end of 2021 is 3523 MW for coal fired power plants and 24,562 MW for Natural Gas Combined Cycle (NGCC) power plants [45]. The PNIEC aligned with the Paris Agreement is committed to decarbonise the electricity generation and Table 8 shows the projected evolution of the installed capacity targets for the years 2025 and 2030.

PNIEC aims 74% of RE in the generation electricity mix by year 2030 combined with a long-expected life for the PHES plants. Furthermore, it expects to reach 100% of RE in electricity generation by year 2050.

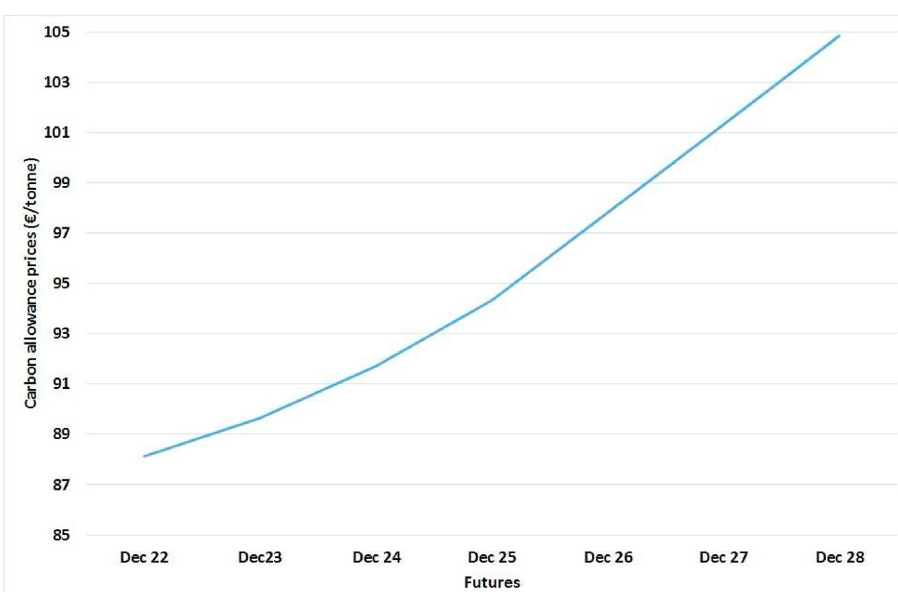

Fig. 15. Carbon allowance prices versus futures. Source: author's own calculations using data from www.barchart.com.

Actually, during the year 2021 the NGCC power plants in Spain are emitting 370 Kg CO_2/MWh [45] that is equivalent to an efficiency of 0.5458 in this type of power plants.

The PHES plant can help to avoid some CO_2 emissions if coordinated with wind energy generation. If the base case is coordinated with wind power energy in the first three years the optimal strategy generates an expected production of 119,541 MWh. If all the PHES production replaces part of the NGCC power plant generation then an emission of 40,230 tonnes of CO_2 is avoided. The mean of CO_2 allowances prices was 34.38 €/tonne in the period 2019–2011 (www.sendeco2.com), then if all emissions were avoided, it is a saving of 1,520,6673 €.

The cost of CO_2 emissions is an important factor to consider either in an investment or when operating PHES and NGCC plants as it can be observed in Fig. 15. The revenue impact depends on many factors, because the NGCC plants usually are marginal (or are near to be marginal) and in addition to the strategy, its variable costs depend on fundamentally in the price offer decision. This variable cost is known as Clean Spark Spread (CSS) the electricity price minus the costs of natural gas and CO_2 emission allowances necessary to produce a MWh.

8. Conclusions

An increase in storage capacity is necessary to ensure Security of Supply (SoS) in a scenario of increased electricity consumption and a generation mix with a greater presence of Renewable Energy (RE) and a lower weight in the mix of thermal power plants.

PHES plants represent a mature, widely used electricity storage technology. However they entail irreversible investments with high construction costs and long useful lifetimes, which makes them high-risk investments subject to multiple uncertainties such as electricity prices and regulation.

The impacts of an optimally-managed PHES power plant using certain price ranges for pumping and others for generation is analysed. There is also a range where the PHES plant is idle. This model can also be used with a short-term strategy, e.g. performing calculations every month and obtaining the corresponding limit prices.

The calculations show that when income from a PHES plant is obtained solely by arbitrage between valley and peak electricity prices, revenues seem not to offset the irreversible investment costs. In our calculations it is assumed that there is no other type of income. All income is obtained from the spot electricity market.

Depending on their characteristics, these plants can contribute more or less to Security of Supply (SoS), but in general there is no guarantee that they will provide an adequate supply in the hours of greatest demand of the year. This is because of uncertainty. Due to this, this strategy cannot fully guarantee that there will be sufficient water at times of maximum demand in the year, which are usually when electricity prices are higher. This predicted behaviour is confirmed by real data. However, security of supply significantly improves when there is a greater volume in the upper reservoir, which highlights the importance of PHES.

The model can be used to assess the economic impact of establishing a minimum reserve capacity at PHES plant with the aim of improving Security of Supply (SoS). The calculations can be used to estimate payments for reserve capacity of PHES plants.

In the case of a PHES plant that operates independently it seems to be a need for a different payment system that can guarantee sufficient income and management oriented towards Security of Supply (SoS).

Finally, if a GENCO strategy is applied and the PHES is coordinated with a wind farm, its income can improve substantially. In addition, the avoided CO_2 emission costs for the PHES plant can be very relevant, if taking into account that these costs can increase a lot in the future.

Authorship statement

All persons who meet authorship criteria are listed as authors, and all authors certify that they have participated sufficiently in the work to take public responsibility for the content, including participation in the concept, design, analysis, writing, or revision of the manuscript. Furthermore, each author certifies that this material or similar material has not been and will not be submitted to or published in any other publication before its appearance Energy Journal.

Authorship contributions

Conception and design of study: L.M. Abadie, N. Goicoechea, Acquisition of data: L.M. Abadie, N. Goicoechea, analysis and/or interpretation of data: L.M. Abadie, N. Goicoechea, Drafting the manuscript: L.M. Abadie, N. Goicoechea, Revising the manuscript critically for important intellectual content: L.M. Abadie, N. Goicoechea, Approval of the version of the manuscript to be published (the names of all authors must be listed): L.M. Abadie, N. Goicoechea

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A

All Equations in Appendix A are obtained from Ref. [42].

It is possible to represent the density function of X_t given X_{t-1} as in Equation (A.1)

$$f(X_t|X_{t-1}) = \lambda\Delta t N_1(X_t|X_{t-1}) + (1-\lambda\Delta t)N_1(X_t|X_{t-1}) \tag{A.1}$$

There is a probability $\lambda\Delta t$ that there will be a jump and then Equation (A.2) applies:

$$N_1(X_t|X_{t-1}) = \frac{1}{\sqrt{2\pi\left(\sigma^2+\sigma_j^2\right)}} e^{-\frac{\left(X_t-\alpha\Delta t-(1-\kappa\Delta t)X_{t-1}-\mu_j\right)^2}{2\left(\sigma^2+\sigma_j^2\right)}} \tag{A.2}$$

There is a probability $(1-\lambda\Delta t)$ that there will be no jump and then Equation (A.3) applies:

$$N_2(X_t|X_{t-1}) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{-\frac{\left(X_t-\alpha\Delta t-(1-\kappa\Delta t)X_{t-1}\right)^2}{2\sigma^2}} \tag{A.3}$$

The parameters $\theta = \{\alpha, \kappa, \sigma, \lambda, \mu_j, \sigma_j\}$ can be calculated by minimising the negative value of the log likelihood function as in Equation (A.4):

$$\min_{\theta} - \sum \text{Unsupported} \upharpoonright_{i=1}^{i=T} \log(f(X_t|X_{t-1})) \quad \text{(A.4)}$$

subject to:

$(1-\kappa\Delta t) < 1$

$\sigma > 0$

$\sigma_j > 0$

$\kappa > 0$

$0 \leq \lambda\Delta t \leq 1$

Appendix B

Table B1
Parameters of the Gouváes Case. Source [36].

Parameter	Description	Value
P_H	Hydraulic Power	880,000 kWh
η_p	Joint pump and alternator performance	0.94176
η_g	Joint turbine and alternator performance	0.84947
H	Height	660 m
g	Gravity acceleration	9.81 m/s^2
Q_p	Flow in Pumping Mode	460,800 m^3/h
Q_g	Flow in Generating Mode	576,000 m^3/h
Efi	Efficiency	0.80

Assuming $\eta_p = 0.94176$ and $\eta_g = 0.8495$, Q_p and Q_g are obtained using Equations B.1 and B.2 according to Ref. [53].

$Q_p = 3600\frac{\eta_p P_H}{9.81\times H} = 460{,}800\ m^3/h$ (B.1)

$Q_g = 3600\frac{P_H}{9.81\times H\times\eta_g} = 576{,}800\ m^3/h$ (B.2)

The efficiency is:

$Efi = \frac{Q_p}{Q_g} = 0.80$ (B.3)

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