Open Access Journal

Journal of Power Technologies 93 (2) (2013) 78–89

journal homepage:papers.itc.pw.edu.pl

Optimization analysis for pumped energy storage systems in small isolated power systems☆

Andreas Poullikkas

Electricity Authority of Cyprus, P.O. Box 24506, 1399 Nicosia, Cyprus

Abstract

In this work, a technical and economic analysis concerning the integration of pumped energy storage plants in small island power systems and in particular in the Cyprus power system is carried out. For the simulation of the current and future Cyprus generation system, the WASP IV software package is employed, which is a specialized simulation software used widely for the selection of the optimum expansion planning of the generation system. The electricity unit cost of the generation system for various investigated scenarios is then calculated. The simulation results indicate that under certain parameters the use of pumped energy storage systems can be beneficial for the large scale integration of renewable energy sources.

Keywords: Pump storage, Power optimization, Power economics, Renewables integration, Energy policy

1. Introduction

Electricity consumption and power demand have significantly increased worldwide over recent years. Also, in order to reduce greenhouse gases emissions, developed countries and especially the European Union (EU) are investing heavily to increase the share of renewable energy sources in power generation (RES-E). These developments will increase energy costs and will create problems in the security of supply. Small isolated island power generation systems will be affected most by the above problems and especially with the introduction of wind energy in the power system, which will cause high variability and uncertainty in power generation and demand for system reserve, thus making the use of pumped hydroelectric energy storage (PHES) systems in ancillary services essential [1]. Therefore, the use of a PHES will provide [2] a number of key factors for new developments and solutions to the security of the electricity supply, reduction of the degree of vulnerability of supplies by diversifying the sources, promotion of the rational use of energy, reduction of the energy dependence on external sources by increasing as much as possible the use of RES-E technologies, guarantee of a stable and safe energy supply contribution to the protection and conservation of the environment [3].

In this work, a technical and economic analysis concerning the integration of PHES plants in small island power systems and in particular in the Cyprus power system is carried out. For the simulation of the current and future Cyprus generation system, the WASP IV [4] software package [4] is employed, which is a specialized simulation software used widely for the selection of the optimum expan-

☆Parts of this work were undertaken while the author was a Visiting Professor in the Department of Mechanical Engineering, College of Engineering, American University of Sharjah, PO Box 26666, Sharjah, United Arab Emirates

Email address: mspoul@ucy.ac.cy (Andreas Poullikkas)

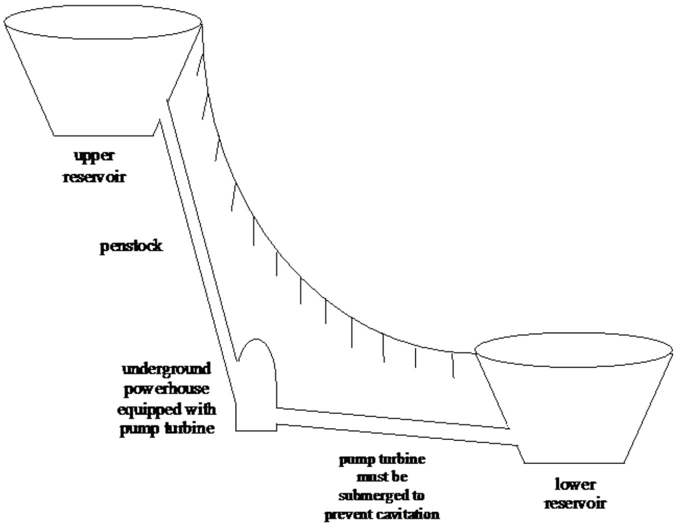

Figure 1: Principle of operation

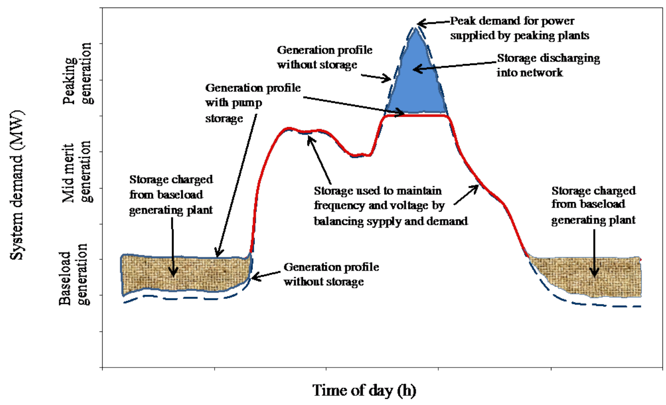

Figure 2: Load demand and generation of PHES

sion planning of the generation system. The electricity unit cost of the generation system for various investigated scenarios is then calculated.

In section 2, the principle of operation of PHES systems is presented. In section 3, the operational characteristics are discussed and in section 4 the simulation proccedure for calculation of the electricity production and pumping cost of a PHES plant is presented. In section 5 the input data, the scenarios investigated and the results obtained are discussed in detail. The conclusions are summarized in section 6.

2. Principle of operation of PHES plants

The fundamental principle of PHES technology is the storage of electric energy in the form of hydraulic potential energy by pumping water to a high elevation, where it can be stored indefinitely and then released to pass through hydraulic turbines and generate electrical energy [5].

A typical PHES plant is composed of two reservoirs of equal volume situated to maximize their height difference, known as the head [6]. As a rule of thumb the head must be in excess of 300 m in order for the PHES plant to become economically viable, however, this will depend on various factors. As illustrated in Figure 1, these reservoirs are connected by a system of waterways along which a pumping-generating station is located. Under favorable geological conditions, the station will be located underground otherwise it will be situated on the lower reservoir. The principal equipment of the station is the pumping-generating unit, which is generally reversible and used for both pumping and power generation, functioning as a motor and pump in one direction of rotation and as a turbine and generator in the opposite direction [7].

The electrical storage volume, therefore, depends on the volume of the reservoirs and the altitude difference between these two reservoirs. To store electricity, water from the bottom reservoir is pumped into the upper one. To generate electricity, the upper reservoir opens the gate and water pours down the pipe, spinning the turbine and generating electricity [8]. Pumping typically takes place mainly during off-peak periods, when electricity demand is low and electricity prices are low. Generation takes place during peak periods, when electricity demand is high [9], as illustrated in Figure 2.

Typically PHES systems come in two types namely: pure PHES systems and pump-back PHES systems. Pure PHES plants rely entirely on water that has been pumped to an upper reservoir from a lower reservoir, a river or the sea, as illustrated in Figure 1. Pure PHES are also known as “closed-loop” or “off-stream”. Pump-back PHES use a combination of pumped water and natural inflow to produce power similar to a conventional hydroelectric power plant. Pump-back PHES systems may be located on rivers or valleys with glacial or hydro inflow [5].

3. Operational characteristics

The PHES is economical as it flattens out the variations in the load on the power grid, permitting thermal power stations, such as coal fired plants and nuclear power plants that provide base load electricity to continue operating at their most efficient capacity, while reducing the need to build special power plants which run only at peak demand times using more costly generation methods [10].

As well as energy management, PHES systems are important components in controlling electrical network frequency, producing reactive power, and providing spinning and standing reserve.

Thermal plants are much less able to respond to sudden changes in electrical demand, which causes frequency and voltage instability. PHES systems in common with other hydroelectric plants can respond to these changes within seconds, thus making it suitable for performing black starts [10]. A summary review, [5], [10], of the operational characteristics of PHES in comparison with conventional power plants is tabulated in Table 1.

Other important advantages of the use of PHES technologies are their high global cycle efficiency, which is the highest efficiency of all energy storage solutions at 77%, and their contribution to increased profitability for plant owners in volatile electricity spot markets, thus allowing optimization of global operations of power plant fleets and electrical network infrastructures [8]. An additional advantage of a PHES plant is the possibility of using the water stored in the reservoirs for the purposes of consumption, irrigation and fire-fighting [1]. A major advantage of combining PHES systems with other sources such as RES-E is the positive environmental impact. Instead of having another plant provide energy during the peak demand hours, the stored energy can be utilized to provide the power. No fossil fuels are burned for this system, nor are there any pollutants released into the atmosphere [10]. For isolated island power systems PHES technology seems to be the most promising way to exploit the available RES-E potential, such as wind potential, to a high degree of penetration. In larger islands such a power plant could substitute one or more base thermal units, making thus the investment even more profitable [1].

The drawbacks of PHES technology are the environmental damage caused by the reservoirs, their high capital cost and the difficulty of finding topographically suitable sites with sufficient water capacity to make the installation of such systems profitable [2]. Apart from that, there are few remaining undeveloped sites where PHES systems could be located and those which would be suitable for new plants could face licensing problems due to environmental concerns. This means that even if a PHES plant finally receives permission, it might take years until all the environmental studies are performed [8].

4. Simulation procedure

The future generation system including PHES systems is simulated using the WASP IV software package [4], which is widely used for automatic generation planning. The WASP IV software package finds the optimal expansion plan for a given power generating system over a period of up to 30 years. The foreseen seasonal load duration curves, the efficiency, the maintenance period and the forced outage rate of each generating plant are taken into account.

The objective function, which shows the overall cost of the generation system (existing and candidate generating plants), is composed of several components. The components related to the candidate generating units are: the capital cost and the salvage capital cost. The components which are related to both the existing and candidate generating units are: the fuel cost, the fixed operation and maintenance (O&M) costs, such as staff cost, insurance charges, rates and fixed maintenance, the variable O&M costs, such as spare parts, chemicals, oils, consumables, town water and sewage. The cost to the national economy of the energy not served (ENS) because of a shortage of capacity or interruptions is also taken into consideration.

The WASP IV package was originally developed in the United States for the needs of the International Atomic Energy Agency (IAEA). It is the most frequently used and best-proven program for electric capacity expansion analysis. It is used for long-term expansion planning for a period of up to 30 years and compares the total costs for the whole generation system for a number of candidate units. In the

Table 1: Typical operating characteristics of power generation plants

Operating characteristic	Nuclear power plants	Coal fired Rankine cycle	Oil fired Rankine cycle	Gas turbine	PHES systems
Normal duty cycle	Baseload	Baseload	Baseload-midmerit	Peak load	Peak load-midmerit
Unit start up-daily	No	No	Yes	Yes	Yes
Load following	No	Yes	Yes	Yes	Yes
Quick start (10 min)	No	No	No	Yes	Yes
Frequency regulation	No	Yes	Yes	No	Yes
Black start	No	No	No	Yes	Yes
Response time to sudden changes	High	Medium	Medium	High	High

production simulation of WASP, a one-year period is divided into, at most, 12 sub-periods for each of which probabilistic simulation is applied. Equivalent load duration curves in the probabilistic simulation are approximated using a Fourier series. Fourier expansion makes it computationally simple to convolve and deconvolve generating units in the probabilistic simulation. The decision of the optimum expansion plan is made using forward dynamic programming. The number of units for each candidate plant type that may be selected each year is specified, in addition to other practical factors that may constrain the solution. If the solution is limited by any such constraints, the input parameters can be adjusted and the model re-run. The dynamic programming optimization is repeated until the optimum solution is found. Each possible sequence of power units added to the system (expansion plan), meeting the constraints, is evaluated by means of the cost function (the objective function),

$$B_j = \sum_{t=1}^{T} \left(I_{jt} - S_{jt} + F_{jt} + M_{jt} + \Phi_{jt} \right) \tag{1}$$

where, B_j is the objective function attached to the expansion plan j, t is the time in years (1, 2, …., T), T is the length of the study period (total number of years), I is the capital investment cost, S is the salvage value of investment cost, F is fuel cost, M is the non-fuel operation and maintenance cost and Φ is the cost of energy not served. All costs are discounted to a reference date at a given discount rate. The optimum expansion plan is the min B_j among all j. Details of the optimization algorithm implementing the above mathematical formulation can be found in [11].

In WASP IV, PHES units save fuel costs by serving the peak load demand, usually served by high fuel cost units, with hydro energy that was pumped to a higher level reservoir during periods of low demand (evening, weekends) when more economic units can be utilized. The PHES plants are limited both in capacity and energy. Their economic evaluation depends on the characteristics of the load duration curve (LDC), the composition of the generating system, the reliability of each unit and the running cost (i.e. fuel and variable O&M) of all types of units.

The main parameters of a PHES plant j are the pumping capacity P in MW, the generating capacity G in MW, the maximum feasible energy generation (storage capacity) E in GWh, the pumping efficiency η_p in %, the generating efficiency η_g in % and the cycle efficiency η_j in %. When more than one PHES plant exists in the system, the plants are aggregated to form an equivalent composite PHES plant as follows:

$$P = \sum_j P_j, \tag{2}$$

$$G = \sum_j G_j, \tag{3}$$

$$E = \sum_j E_j, \tag{4}$$

$$\eta_p = \sum_j \eta_{pj} \frac{P_j}{P}, \tag{5}$$

$$\eta_g = \sum_j \eta_{gj} \frac{G_j}{G}, \tag{6}$$

$$\eta = \eta_p \eta_g \tag{7}$$

where P is the composite PHES plant pumping capacity in MW, G is the composite PHES plant generating capacity in MW, E is the composite PHES plant storage capacity in MW, η_p is the composite PHES plant pumping efficiency in %, η_g is the composite PHES plant generating efficiency in % and η is the composite PHES plant cycle efficiency %.

The weighting of the individual efficiencies with the individual capacities assumes that all projects have the same capacity factor and hence is only an approximation. The pumping (i.e., charging) and generating operations can be considered independently. The generation amount is given by the following equation:

$$E_g = \eta \cdot E_p, \tag{8}$$

where E_g is the generation in GWh and E_p is the pumping in GWh.

The individual PHES plants are combined into one equivalent PHES described by its pumping potential (pumped storage energy), nominal capacity, cycle efficiency and O&M cost. The pumping process is performed in every period of the year. In order to calculate the potential pumping of the thermal units to fill the reservoir, the procedure starts from the thermal units, which are lower in the loading order and can produce extra energy than that expected (actually produced on the given LDC). For each thermal plant j, the program computes the energy that can be replaced (E_{gj}) by the generation of the PHES plant and the energy that is available for pumping (E_{pj}). In the case where the PHES plant is able to offset generation from the thermal plant considered (i.e. $E_{gj} > 0$), the load is reduced by the generating capacity of the PHES plant. In a similar way, when energy is available for pumping purposes (i.e. $E_{pj} > 0$), the load for the thermal plant considered is increased by the pumping capacity of the PHES plant.

After the energy calculation it is possible to form a complete loading order list of plants, containing energy produced in the system without the PHES plant that could be replaced by the PHES plant and energy available for pumping purposes at every plant. The optimal allocation procedure is essentially a search for two power levels which define the PHES plant operation. The largest amount of energy available for PHES plant operation can be determined by summing up generation on a plant by plant basis (pumping from the bottom, generating from the top). In order to reduce the unserved energy remaining after thermal dispatch and at the same time improve the system reliability, the aggregate PHES plant is dispatched in two modes.

First, the PHES plant is dispatched as though the PHES plant loading order were continuations of thermal loading order and P-S generating capacity is to be used for peaking service. This PHES plant generation is considered compulsory operation and is uneconomical in that it requires additional thermal generation through assignment of pumping duty without any reduction of thermal generation. The pumping duty is assigned to the lowest cost thermal units.

After the PHES plant is dispatched for compulsory operation it is next considered for economic operation. Economic operation is only possible when the cost of pumping water into the reservoir is cheaper than the cost of thermal generation replaced by the PHES plant generation. Pumping operation is economic only if

$$C_{pi} < \eta C_{gi}, \tag{9}$$

where C_{pi} is the operating cost of thermal unit i participating in pumping operation and C_{gj} is the operating cost of thermal unit j which is being offloaded by the PHES plant. When this inequality is not satisfied the pumping operation stops. The procedure can result in several different cases. First, the available energy may not be sufficient to meet the minimum pumping requirements (for the PHES plant as the last plant in the loading order). In this case all the available energy for pumping is used and the procedure stops. Second, pumping energy is available but the operation of the PHES plant is not economic because the cost of generation for the thermal plant to be replaced by PHES plant generation is lower than that of the pumping plant adjusted for PHES plant efficiency. In this case the PHES plant operation stops. The procedure also stops when all the PHES plant generation capability (maximum feasible generation) is exhausted (the energy not needed is not pumped).

In the procedure presented above, the available energy for pumping in a period considered has to be used in the same period. The procedure does not take into account the possibility of storing energy within one period in order to use it in another subsequent period so as to optimize the generation from the PHES plant.

5. PHES plant integration in the Cyprus power system analysis

In this section, a technical and economic analysis concerning the integration of a PHES plant in the Cyprus power system is carried out. Firstly, the input data, the assumptions and the scenarios investigated are presented and then the results obtained are analyzed.

5.1. Input data and assumptions

For the period 2012–2020 the actual projections of the Cyprus Transmission System Operator (TSO) are taken into account. For the years 2021–2031 a steady annual increase for both electricity demand and peak load demand of 3% and 3.5%, respectively is assumed. The fuel costs for heavy fuel oil (HFO), gasoil and natural gas in nominal prices, including the cost of regasification, for the period under investigation, were based on the forecast scenario provided in [11]. Also, due to the recent discovery and confirmation of natural gas reserves within the Cyprus exclusive economic zone, three further cases of 20% increase and 20% and 40% reduction on the natural gas projected price of the forecast scenario in nominal prices are used. In order to account for the EU ETS system trading, the projected CO_2 ETS price projections for the years under study provided in [11] are used, with an average nominal price of €30/t.

For the purposes of this analysis the technical and economic parameters for each of the existing and committed conventional power generation units of the Cyprus power system are taken into account. All data is based on actual costs derived from manpower, spares requirements, maintenance costs, unit availabilities and operation efficiencies. The commissioning and retirement years of the existing units are also taken into account and follow the long-term strategic planning that has been developed for the Cyprus generation system [11]. The technical and economic parameters for each of the existing and committed RES-E units already in operation are taken into account. Currently in Cyprus, the share of RES-E is very low. It currently features 133.5 MWe wind parks, a number of small-rooftop PV systems and PV parks up to 150 kW, with a total combined grid connected capacity of approximately 7 MWe, and biomass gasification units (the majority of which use animal or domestic waste) with a total grid connected capacity of 7.2 MWe. A summary of the existing and committed RES-E units taken into account in this study is provided in [11]. Moreover, by the end of 2012, additional wind parks with total capacity of 31.5 MWe are expected to be fully operational and total wind power capacity is expected to increase to 165 MWe by 2013. According to [11], the RES-E contribution to the power generation system capacity reserve margin is (a) wind 0% contribution, (b) PVs 50% contribution, (c) biomass 100% contribution and (d) CSP with 6 h thermal storage 100% contribution.

For the purposes of this analysis three candidate PHES plants are used with the technical and economic parameters tabulated in Table 2, as provided in [12]. The three PHES plants could be commissioned in the Cyprus power generation system after 2021 in three candidate locations namely Kourris (130 MWe), Kannaviou (200 MWe) and Arminou (200 MWe), respectively. Each PHES plant has with overall efficiency of 77% and continuous full load turbine operation of 8 h.

For the optimization software package simulations all costs are updated to 2012 values. In particular, the horizon of this study covers a period of 30 years from 2012 up to 2041 with a discount rate of 8%, an average annual inflation rate of 2.3% and an average loan interest of 7.1% as provided in [11].

Table 2: Technical and economic parameters of candidate PHES plants [12]

PHES Technology	130 MW	200 MW	200 MW
Year of operation	2021	2021	2021
Nominal capacity, MWe	130	200	200
Generation capacity, MWe	132.2	203.2	203.2
Pumping capacity, MWe	127.2	186.4	189.6
Overall efficiency, %	77	77	77
Full load operation for electricity production, h	8	8	8
Capital cost, €/kWe (real prices)	1185	760	754
O&M cost, €/kW-month	0.915	0.646	0.613

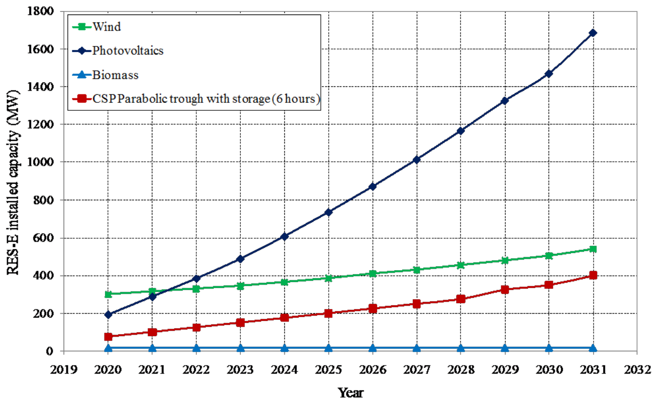

Figure 3: Increased RES-E installed capacity

5.2. *Scenarios investigated*

In order to investigate whether the integration of a PHES system in the Cyprus power system is technically and economically viable, two groups of scenarios were investigated. The business as usual scenarios (BAU) and the increased RES-E scenarios as follows:

- Scenario BAU: RES-E energy share to reach 16% of total expected electricity demand in 2020, as given in [11] and then the RES-E capacity to remain constant up to the end of the assessment period,

- Scenario BAU, PHES 130 MW: integration with the BAU scenario with a PHES plant of 130 MWe (at Kourris) after 2021 and the remaining capacity to be satisfied by natural gas combined cycle (NGCC) technologies of 220 MWe capacity each,

- Scenario BAU, PHES 200 MW: integration with the BAU scenario with a PHES plant of 200 MWe (at Kannaviou) after 2021 and the remaining capacity to be satisfied by NGCC technologies of 220 MWe capacity each,

- Scenario BAU, PHES 330 MW: integration with the BAU scenario with two PHES plants, one of 130 MWe (at Kourris) and one of 200 MWe (at Kannaviou) after 2021 and the remaining capacity to be satisfied by NGCC technologies of 220 MWe capacity each,

- Scenario BAU, PHES 530 MW: integration with the BAU scenario with three PHES plants, one of 130 MWe (at Kourris), one of 200 MWe (at Kannaviou) and one of 200 MWe (at Arminou) after 2021 and the remaining capacity to be satisfied by NGCC technologies of 220 MWe capacity each,

- Scenario increased RES-E: RES-E energy share to increase from 16% in 2020 to 50% in 2031 of total expected electricity demand. Expansion of the power generation system with RES-E technologies as illustrated in Figure 3 and the remaining capacity to be satisfied by NGCC technologies of 220 MWe capacity each,

- Scenario increased RES-E, PHES 130 MW: integration with the increased RES-E scenario with a PHES plant of 130 MWe (at Kourris) after 2021 and the remaining capacity to be satisfied by NGCC technologies of 220 MWe capacity each,

- Scenario increased RES-E, PHES 200 MW: integration with the increased RES-E scenario with a PHES plant of 200 MWe (at Kannaviou) after 2021 and the remaining capacity to be satisfied by NGCC technologies of 220 MWe capacity each,

- Scenario increased RES-E, PHES 330 MW: integration with the increased RES-E scenario with two PHES plants, one of 130 MWe (at Kourris) and one of 200 MWe (at Kannaviou) after 2021 and the remaining capacity to be satisfied by NGCC technologies of 220 MWe capacity each,

- Scenario increased RES-E, PHES 530 MW: integration with the increased RES-E scenario with three PHES plants, one of 130 MWe (at Kourris), one of 200 MWe (at Kannaviou) and one of 200 MWe (at Arminou) after 2021 and the remaining capacity to be satisfied by NGCC technologies of 220 MWe capacity each.

Due to the recent discovery and confirmation of natural gas reserves within the Cyprus exclusive economic zone and in order to investigate the effect of the natural gas price in the above ten scenarios, four cases concerning natural gas projected price were investigated: natural gas price base case (average price €12.52/MMBTU), natural gas 20% price decrease case (average price €10.02/MMBTU), natural gas 40% price decrease case (average price €7.51/MMBTU) and natural gas 20% price increase case (average price €15.03/MMBTU).

5.3. Results

The effect of PHES technologies on natural gas consumption for the different scenarios examined for the natural gas price base case is illustrated in Figure 4. The effect of PHES technologies on the natural gas consumption for the different scenarios examined for the natural gas 20% price decrease case is the same as that of the natural gas base case. The same is true for the natural gas 40% price decrease case. In contrast, the effect of PHES technologies on the natural gas consumption for the different scenarios examined for the natural gas 20% price increase case is presented in Figure 5.

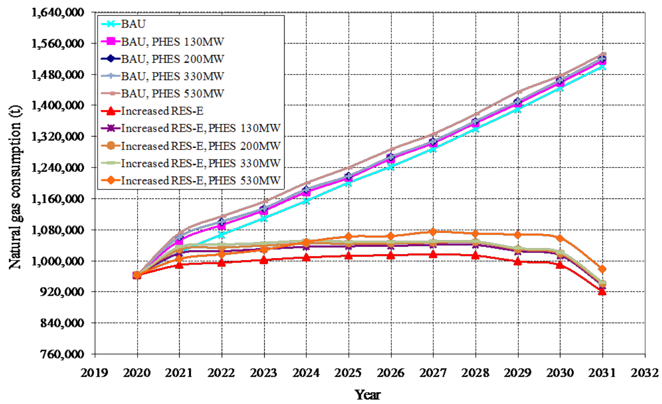

Figure 4: Power generation system natural gas consumption results for natural gas price base case, natural gas 20% price decrease case and natural gas 40% price decrease case

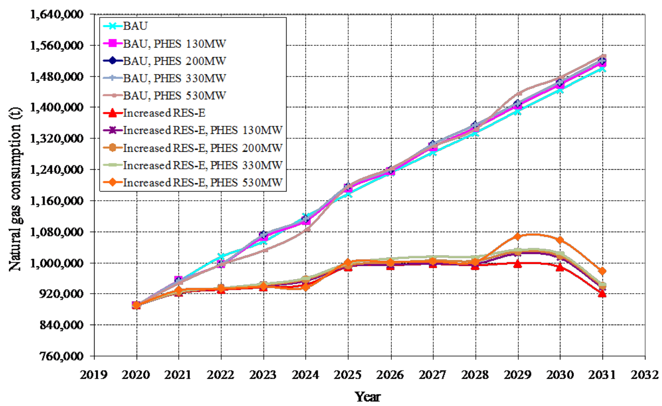

Figure 5: Power generation system natural gas consumption results for the natural gas 20% price increase case

Considering Figure 4, for the year 2028 in the case of the BAU scenario natural gas consumption is estimated at approximately 1340030 t whereas for PHES 530 MW scenario this increases to approximately 1379270 t. As for the increased RES-E scenario for the same year natural gas consumption is estimated at approximately 1014150 t whereas for the increased RES-E, PHES 530 MW scenario this increases to approximately 1071300 t. Considering Figure 5, for the year 2028 in the case of the BAU scenario natural gas consumption is estimated at approximately 1334420 t whereas for the PHES 530 MW scenario this increases to approximately 1344710 t. As for the increased RES-E scenario for the same year natural gas consumption is estimated at approximately 993170 t whereas for the increased RES-E, PHES 530 MW scenario this increases to ap-

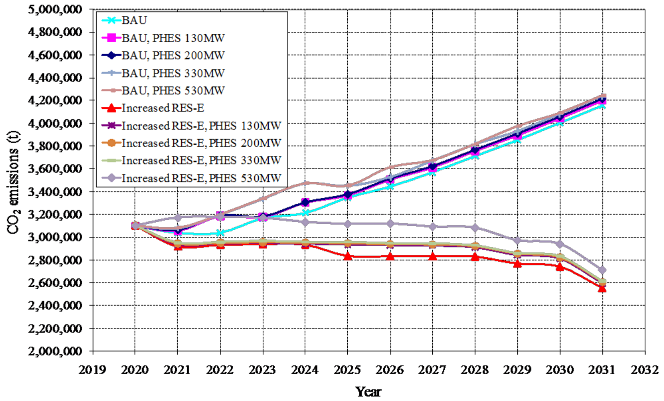

Figure 6: Annual CO_2 emissions results for natural gas price base case, natural gas 20% price decrease case and natural gas 40% price decrease case

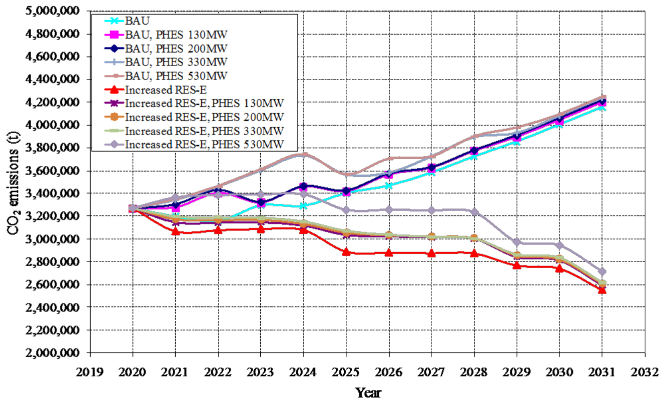

Figure 7: Annual CO_2 emissions results for the natural gas 20% price increase case

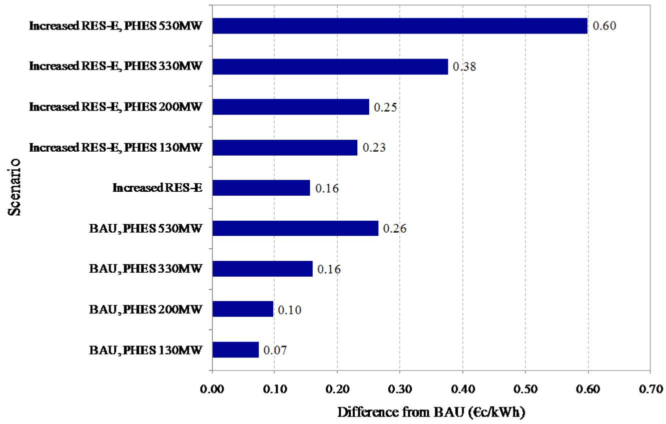

Figure 8: Differential electricity unit cost increase from the BAU scenario for the base case natural gas price projections

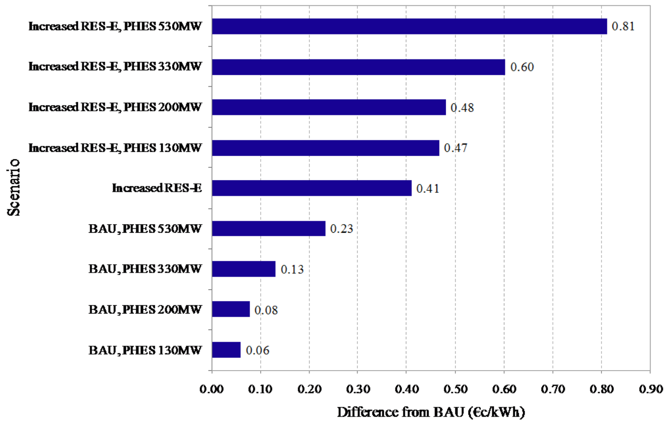

Figure 9: Differential electricity unit cost increase from the BAU scenario for the natural gas 20% price decrease case

proximately 1002150 t.

The optimum results concerning the power generation system CO_2 emissions for the period from 2020 up to 2031 for all scenarios investigated for the natural gas price base case are shown in Figure 6.

The optimum results concerning the power generation system CO_2 emissions for the period from 2020 to 2031 for all scenarios investigated for the natural gas 20% price decrease case are the same as those of the natural gas base case. The same is true for the natural gas 40% price decrease case. In contrast, the optimum results concerning the power generation system CO_2 emissions for the period from 2020 to 2031 for all scenarios investigated for the natural gas 20% price increase case are presented in Figure 7. The annual CO_2 emission quantities for all cases increase slightly with the increase of PHES capacity, due to the increased consumption of natural gas. However, by increasing the penetration of RES-E technologies the annual CO_2 emission quantities are significantly reduced compared to the BAU scenario.

The optimum results concerning the power generation system electricity unit cost difference for each individual scenario compared to the BAU scenario for each case of natural gas projected price are illustrated in Figure 8–Figure 11, respectively.

It is clear that for the BAU scenarios with or without PHES for all cases of the natural gas projected price, the difference in electricity unit cost compared to the BAU scenario increases (a) as the PHES installed capacity increases and (b) as the natural gas projected price increases.

Specifically, for the natural gas price base case for

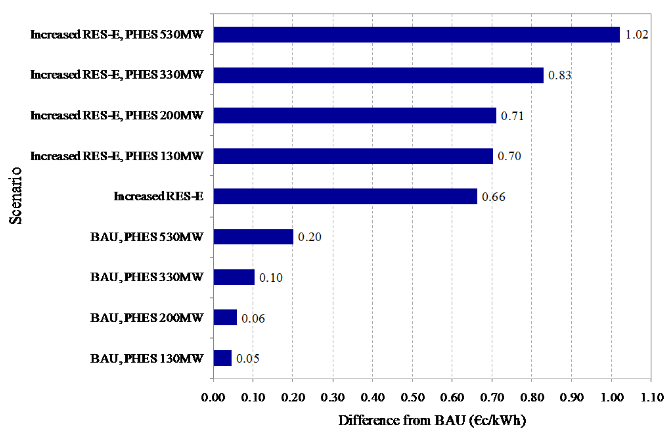

Figure 10: Differential electricity unit cost increase from the BAU scenario for the natural gas 40% price decrease case

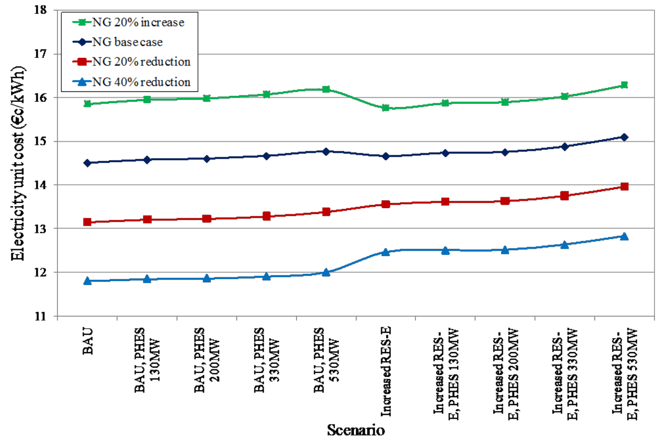

Figure 12: Electricity unit cost overall results for all four different cases of natural gas projected price

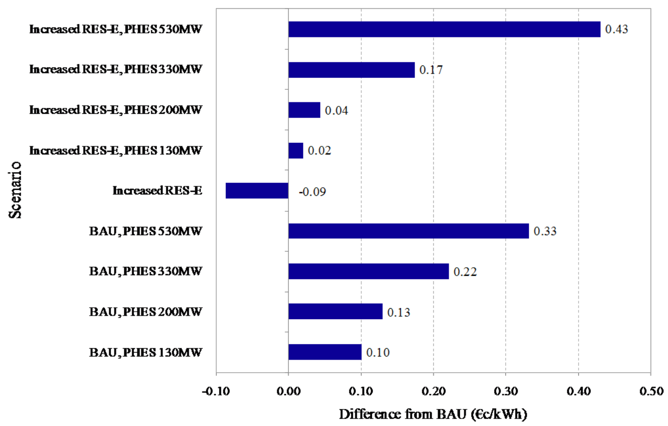

Figure 11: Differential electricity unit cost increase from the BAU scenario for the natural gas 20% price increase case

the PHES 530 MW scenario, the electricity unit cost is €c0.26/kWh higher than the BAU scenario, which corresponds to €c14.77/kWh.

For the natural gas 20% price decrease case for the PHES 530 MW scenario, the electricity unit cost is €c0.23/kWh higher than the BAU scenario, which corresponds to €c13.39/kWh. For the natural gas 40% price decrease case for the PHES 530 MW scenario, the electricity unit cost is €c0.20/kWh higher than the BAU scenario, which corresponds to €c12.01/kWh. Whereas, for the natural gas 20% price increase case for the PHES 530 MW scenario, the electricity unit cost is €c0.33/kWh higher than the BAU scenario, which corresponds to €c16.19/kWh.

Regarding the increased RES-E scenarios with or without PHES, the difference in electricity unit cost compared to the BAU scenario again increases as the PHES installed capacity increases. However, as the natural gas projected price is reduced, the difference in the electricity unit cost compared to the BAU scenario increases. The above observation is clearer in Figure 12.

As the natural gas projected price decreases, the electricity unit cost of the increased RES-E with or without PHES scenarios increases to levels which are higher than those of the BAU scenarios with or without PHES. This occurs due to the fact that the number of new NGCC plants that will be commissioned will be reduced significantly in the increased RES-E scenarios with or without PHES compared to the BAU scenario, which causes a larger difference in the electricity unit cost for lower natural gas projected price than higher and vice versa. For the natural gas 20% price increase case, the increased RES-E scenario without PHES is observed to have an electricity unit cost lower than that of the BAU scenario. This is because the increase in the electricity unit cost due to CO_2 ETS is lower than that of the BAU scenario, as more RES-E will be installed in the increased RES-E scenario which corresponds to reduced CO_2 emissions as well as to lower fuel consumption. This negative difference is higher than the positive increase in the electricity unit cost excluding CO_2 ETS and, thus, the overall difference is negative corresponding to lower electricity unit cost.

Specifically, for the natural gas price base case, the electricity unit cost increases from €c14.51/kWh in the BAU scenario to €c15.10/kWh in the increased RES-E, PHES 530 MW scenario. For the natural gas 20% price decrease case, the electricity unit cost increases from 13.16 €c/kWh in the BAU scenario to €c13.97/kWh in the increased RES-E, PHES 530 MW scenario. For the natural gas 40% price decrease case, the electricity unit cost increases from €c11.81/kWh in the BAU scenario to €c12.83/kWh in the increased RES-E, PHES 530 MW scenario. For the natural gas 20% price increase case, the electricity unit cost increases from €c15.86/kWh in the BAU scenario to €c16.29/kWh in the increased RES-E, PHES 530 MW scenario.

The WASP analysis performed for the purpose of this study does not take into consideration features of the PHES systems which are beneficial to system operation and/or flexibility, reduced start-ups and/or shutdowns of conventional units and capability to provide ancillary services. The above features may actually reduce to a certain extent the CO_2 emissions and, thus, the electricity unit cost. More importantly, they facilitate the integration of RES-E in the Cyprus power system and may indeed be essential for the large scale integration of RES-E, especially wind energy. The small increase in CO_2 emissions and electricity unit cost shown in this study may well be justified if consideration of these non-salient features of PHES plants are taken into account.

6. Conclusions

In this work, a technical and economic analysis concerning the integration of a PHES plant in the Cyprus power system was carried out. For the simulation of the current and future Cyprus generation system, the WASP IV software package was used and the electricity unit cost of the generation system for various investigated scenarios was then calculated. The optimum results concerning the power generation system electricity unit cost difference for each individual scenario compared to the BAU scenario indicated that for the BAU scenarios with or without PHES for all cases of the natural gas projected price, the electricity unit cost difference increased (a) as the PHES installed capacity increased and (b) as the natural gas projected price increased. Regarding the increased RES-E scenarios with or without PHES the difference in electricity unit cost compared to the BAU scenario as in the case of BAU scenarios, increased as the PHES capacity increased. However, as the natural gas projected price was reduced, the difference in the electricity unit cost compared to the BAU scenario increased. This occurs due to the fact that the number of the new NGCC plants that will be commissioned will be reduced significantly in the increased RES-E scenarios with or without PHES compared to the BAU scenario, which causes a larger difference in the electricity unit cost for the lower natural gas projected price than the higher one and vice versa. For the natural gas 20% price increase case, the increased RES-E scenario without PHES was observed to have an electricity unit cost lower than that of the BAU scenario. This is because the increase in the electricity unit cost due to CO_2 ETS was lower than that in the BAU scenario as more RES-E will be installed in the increased RES-E scenario which corresponds to reduced CO_2 emissions as well as to lower fuel consumption. This negative difference was higher than the positive increase in the electricity unit cost excluding CO_2 ETS and thus the overall difference was negative, corresponding to lower electricity unit cost.

References

[1] J. Anagnostopoulos, D. Papantonis, Pumping station design for a pumped-storage wind-hydro power plant, Energy Conversion and Management 48 (2007) 3009–3017.

[2] C. Bueno, J. A. Carta, Wind powered pumped hydro storage systems, a means of increasing the penetration of renewable energy in the canary islands, Renewable and Sustainable Energy Reviews 10 (2006) 312–340.

[3] I. Hadjipaschalis, A. Poullikkas, V. Efthimiou, Overview of current and future energy storage technologies for electric power applications, Renewable and Sustainable Energy Reviews 13 (2009) 1513–1522.

[4] International Atomic Energy Agency, Vienna, Wien Automatic System Planning (WASP) Package: A Computer Code for Power Generating System Expansion Planning Version WASP-IV with User Interface User's Manual (2006).

[5] J. Deane, B. Ó Gallachóir, Techno-economic review of existing and new pumped hydro energy storage plant, Renewable and Sustainable Energy Reviews 14 (2010) 1293–1302.

[6] A. Poullikkas, Introduction to Power Generation Technologies, NOVA Science Publishers Inc., New York, 2009.

[7] Pumped hydroelectric storage, www.rkma.com.
[8] Survey of energy storage options in europe, Tech. rep., London Research International Ltd (2010).
[9] Why have pumped storage?, www.hydropower.org.
[10] B. Dursun, B. Alboyaci, The contribution of wind-hydro pumped storage systems in meeting turkey's electric energy demand, Renewable and Sustainable Energy Reviews 14 (2010) 1979–1988.
[11] A. Poullikkas, G. Kourtis, I. Hadjipaschalis, A hybrid model for the optimum integration of renewable technologies in power generation systems, Energy Policy 39 (2011) 926–935.
[12] A. Poullikkas, A. Petrou, A. Varnavas, M. Skordelis, Z. Adamantos, I. Hadjipaschalis, G. Kourtis, Parametric feasibility study for the integration of pumped hydroelectric energy storage systems in cyprus power system, Tech. Rep. TR/2011/ET/10, Electricity Authority of Cyprus (2012).