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Practical operation strategies for pumped hydroelectric energy storage (PHES) utilising electricity price arbitrage

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ABSTRACT

In this paper, three practical operation strategies (24Optimal, 24Prognostic, and 24Hsitrocial) are compared to the optimum profit feasible for a PHES facility with a 360 MW pump, 300 MW turbine, and a 2 GWh storage utilising price arbitrage on 13 electricity spot markets. The results indicate that almost all (~97%) of the profits can be obtained by a PHES facility when it is optimised using the 24Optimal strategy developed, which optimises the energy storage based on the day-ahead electricity prices. However, to maximise profits with the 24Optimal strategy, the day-ahead electricity prices must be the actual prices which the PHES facility is charged or the PHES operator must have very accurate price predictions. Otherwise, the predicted profit could be significantly reduced and even become a loss. Finally, using the 24Optimal strategy, the PHES profit can surpass the annual investment repayments required. However, over the 5-year period investigated (2005–2009) the annual profit from the PHES facility varied by more than 50% on five out of six electricity markets considered. Considering the 40-year lifetime of PHES, even with low investment costs, a low interest rate, and a suitable electricity market, PHES is a risky investment without a more predictable profit.

1. Introduction

Many studies have analysed and compared a wide range of energy storage alternatives for future energy systems based on electricity (Connolly and Leahy, 2010; Ekman and Jensen, 2010; Gonzalez et al., 2004; Ibrahim et al., 2008; Kaldellis et al., 2009; Kondoh et al., 2000), heat (Connolly and Leahy, 2010; Lund and Clark, 2002; Mathiesen and Lund, 2009), and even transport (Kempton and Tomic, 2005; Lund and Kempton, 2008). Among other things, these studies indicate that pumped hydroelectric energy storage (PHES) is the most utilised and mature large-scale energy storage technology currently available for electricity (Connolly and Leahy, 2010; Ekman and Jensen, 2010; Gonzalez et al., 2004; Ibrahim et al., 2008), but its major drawback is the lack of suitable sites (Ekman and Jensen, 2010; Ibrahim et al., 2008; Kaldellis et al., 2009; Kondoh et al., 2000). However, recent reports show that there is over 7 GW of new PHES plants planned in the EU alone (Deane et al., 2010), there are more suitable PHES sites available than conventionally assumed (Connolly and MacLaughlin, 2010; Connolly et al., 2010; Spirit of Ireland, 2009; Yang and Jackson, 2011), and PHES can enable higher wind penetrations at lower costs onto some conventional power systems (Benitez et al., 2008; Kapsali and Kaldellis, 2010; Perez-Diaz et al., 2010). Hence, PHES will have a large role in future electricity grids. Therefore, this study investigates if it is possible to profit from a PHES facility on existing electricity markets.

A detailed description of PHES's operation, its parameters, existing facilities, and proposed sites is available from the American Society of Civil Engineers (1996), Connolly and Leahy (2010), and Deane et al. (2010). In a deregulated electricity market, an energy storage facility is typically defined as a merchant unit, which maximises its profits subject to technical constraints, or as a system asset, which is managed by the system operator to assist in maintaining system security and in reducing operational costs (Nyamdash et al., 2010). As a merchant unit, an energy storage facility will earn most of its revenue from the sale of electricity to the market (Loisel et al., 2010; Nyamdash et al., 2010). Hence, this work investigates how an energy storage facility can operate to maximise its revenue from the purchase of low-cost off-peak electricity and the sale of high-cost peak electricity on the market.

Previous studies have also assessed the economic viability of energy storage as a merchant unit. Furusawa et al. (2007) analysed energy storage as a demand side management tool

Abbreviations: EA, Ex-ante (predicted day-ahead) electricity prices in Ireland; EP2, Ex-post (final) electricity prices in Ireland; PHES, pumped hydroelectric energy storage

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Nomenclature

Symbols

C_P	capacity of the PHES pump (MW)
C_S	capacity of the PHES storage (GWh)
C_T	capacity of the PHES turbine (MW)
I_P	investment cost of pump (M€/MW)
I_S	investment cost of storage (M€/GWh)
I_T	investment cost of turbine (M€/MW)
I_{Annual}	total annual repayments for PHES investment (M€)
K	constant (see Eq. (3))
MAXhour	hour that contains the maximum electricity price (h)
MC_P	marginal operating cost of pumping for the PHES facility (€/MWh)
MC_{prod}	marginal operating cost for the PHES facility (€/MWh)
MC_G	marginal operating cost of generating for the PHES facility (€/MWh)
MINhour	hour that contains the minimum electricity price (h)
$O\&M_{Fixed}$	fixed operation and maintenance costs (% of investment)
$\overline{P}$	average price over the next 24 h (€/MWh)
P_{buy}	buying price for the PHES pump (€/MWh)
P_{Max}	available pump capacity at the minimum price hour (MW)
P_{sell}	selling price for the PHES turbine (€/MWh)
T_{Max}	available turbine capacity at the maximum price hour (MW)
i	interest rate (%)
n	lifetime of PHES facility (years)
ΔP	price difference (€/MWh)
η_P	efficiency of the PHES when pumping (%)
η_G	efficiency of the PHES when generating (%)

utilising electricity prices for domestic scale consumers. Sioshansi et al. (2009) investigated the arbitrage value of small-scale energy storage for the PJM market in the USA, while Walawalkar et al. (2007) analysed the potential of sodium sulphur batteries and flywheel energy storage systems in New York state's electricity market. Kazempour et al. (2009b) completed an economic comparison between emerging (sodium sulphur battery) and traditional (PHES) electric energy storage technologies assuming perfect pricing foresight one week in advance. Lund and Salgi (2009) along with Lund et al. (2009) analysed various operating strategies and the corresponding profits from a compressed air energy storage on the Danish electricity market, Kazempour et al. (2009a) created a scheduling tool for a group of hydro plants supplemented by a PHES facility, Figueiredo and Flynn (2006) optimised the size of two specific PHES plants in Alberta, Canada, based on electricity arbitrage profits. Muche (2009) developed a model based on the German electricity market which included future price-based unit commitment planning when evaluating PHES. This study outlined the importance of considering the scope of future actions when evaluating PHES. Finally, Kanakasabapathy and Swarup (2010a, 2010b) created a bidding strategy for PHES based on day-ahead market prices, but assumed that pumping always takes place before generation, which may not be suitable for all electricity markets.

To compliment these studies, the objectives of this work are to identify the maximum feasible profit that a PHES facility can achieve on an electricity market with perfect pricing foresight for 1 year, to compare this to a range of realistic operating strategies which could be put into practise, and to investigate the economic viability of a PHES facility utilising price arbitrage on various electricity markets.

2. Methodology

In total four different operation strategies were created for energy storage on a liberalised electricity market, which are called 'Optimal', '24Historical', '24Prognostic', and '24Optimal'. The Optimal operation strategy tries to find the maximum theoretical operational income given an hourly time series of electricity prices over a 1-year period. The algorithm can be summarised by repeating the following steps (this is analytically illustrated in the Appendix):

1. Identify the hour of the maximum electricity price (MAXhour) in the spot market price series. Such hour is given priority when operating the turbine. (In the following iterations, hours already identified are disregarded and the hour of the remaining maximum price is picked).
2. In this step, the hours before and after MAXhour are examined to identify the earliest hour before MAXhour and the latest hour after MAXhour where the pump can operate. This range constitutes the time space in which recharging/discharging is possible.
   a. Before MAXhour: If the pump is going to operate before MAXhour, then there must be space within the reservoir at the time the pump is operated so energy can be stored for discharging during MAXhour. If the reservoir is full, then the pump could not operate and hence, the earliest hour before MAXhour which the pump can operate is the hour after the last time the storage was full.
   b. After MAXhour: If the pump is going to operate after MAXhour, then there must be energy in the reservoir so that it can be used by the turbine during MAXhour. If the reservoir is empty, then there would be no energy for the turbine to use at MAXhour which could be replaced by the pump at a later date. Hence, the latest hour after MAXhour which the pump can operate is the hour before the storage is emptied.
   c. The range can very well constitute only the MAXhour itself, in which case the plant will not operate.
3. Identify the minimum electricity price, MINhour, within the range defined in step 2. Such hour is given priority when operating the pump. (In the following iterations, hours already identified are disregarded and the hour of the remaining minimum price is picked.)
4. Calculate the marginal operating cost (MC_{prod}) using Eq. (1) based on the minimum price (P_{buy}) found in step 3. If the maximum electricity price (P_{sell}) found in step 1 is higher than the marginal production cost (MC_{prod}), the calculation proceeds to step 5.

$$MC_{prod} = MC_G + [(P_{buy} + MC_P)/(\eta_P * \eta_G)] \tag{1}$$

5. Determine the "operation bottlenecks" in the range between the maximum and minimum prices. In the case that 1 h of pump operation is compensated for by exactly 1 h of turbine operation there is no bottleneck. Otherwise, the turbine and/or the pump may have to partly load and the bottleneck is identified as the minimum of the following four considerations:
   a. Available turbine capacity at the maximum price hour.
   b. Available pump capacity at the minimum price hour.