MELBOURNE ENERGY INSTITUTE

THE UNIVERSITY OF MELBOURNE

Opportunities for Pumped Hydro Energy Storage in Australia

Arup-MEI Research

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1. Executive summary

Pumped hydroelectricity energy storage (PHES) is by far the most significant form of large-scale energy storage in use around the world today with approximately 130 GW of generation capacity installed. PHES facility construction is resurging globally as evolving electricity supply systems place greater value on stored energy. Australia has approximately 1.5 GW of PHES capacity; however, no large-scale facilities have been installed in the last 30 years. This paper examines opportunities for the construction of additional large-scale PHES facilities in Australia.

With PHES, energy is stored by pumping water from a lower reservoir to a second reservoir at a higher elevation. This stored potential energy is later converted to electricity by passing the stored water through an electricity-generating turbine and returning the water to the lower reservoir. Used overseas since the 1890's and in Australia since 1973, PHES has in recent decades been used to balance times of low and high electricity demand in grids that employ constantly-loaded nuclear or coal-fired electricity generation.

Now, in today's rapidly-evolving and increasingly renewables-based electricity supply systems, PHES is used to balance times of low and high electricity supply from variable energy sources such as wind and solar-photovoltaic. PHES can also assist grid frequency regulation and voltage support. These modern benefits might apply especially where renewable energy sources are located on the fringes of a constrained electricity grid. Growing PHES construction activity overseas may indicate that PHES can find economic application in Australia.

Further Australian PHES deployment, beyond the capacity already in place, has not received adequate attention. This is because of the perceived lack of economic need and also because suitable PHES development sites are thought to be rare.

This University of Melbourne Energy Institute (MEI) study sought to deepen Australian-specific PHES knowledge by:

- reviewing the technological and economic state of PHES deployment globally,
- developing high-level cost estimating and mapping tools that can be used to quickly identify potential PHES sites,
- analysing the economics of new PHES facilities at specific Australian locations operating within Australian electricity markets.

This MEI study found that as an alternative to using natural valleys, there is potential in Australia to construct artificial reservoirs, known as "turkey-nest" type dams, for PHES service. "Turkey-nest" type dams are already widely used around the world as a component of PHES facilities.

Further, this study found that coastal seawater PHES, which uses the ocean as the lower reservoir, may have economic application in Australia.

The combination of coastal seawater PHES and a "turkey-nest" type storage reservoir exists at only one place in the world. It has been operating successfully since 1999 (14 years) at Yanbaru on the island of Okinawa, Japan (see Figure 1). Technical details of this facility, obtained during an MEI site visit, are described in this paper.

Elsewhere in the world, coastal seawater PHES is being examined for Sonoma County California, and has also been studied for Hawaii, Ireland, and Latvia.

Figure 1: Yanbaru seawater PHES plant on Okinawa Island, Japan. (Renew Economy, 2013)

MEI's scoping-level capital cost estimates for seawater "turkey-nest" type PHES facilities are within the range of PHES capital costs found in the literature, and could be as low as A$ 100,000/MWh to A$ 200,000/MWh.

Some results of MEI's terrain and cost mapping for the Spencer Gulf region of South Australia are shown in Figure 2. The white and red contours depict potential seawater "turkey-nest" type PHES sites located along the coasts of the Eyre and Yorke Peninsulas. This high-level site analysis considers parameters such as site elevation, distance from the coast, and construction costs, while ignoring parameters such as seawater quality, conservation values, and competing land-use and ownership constraints.

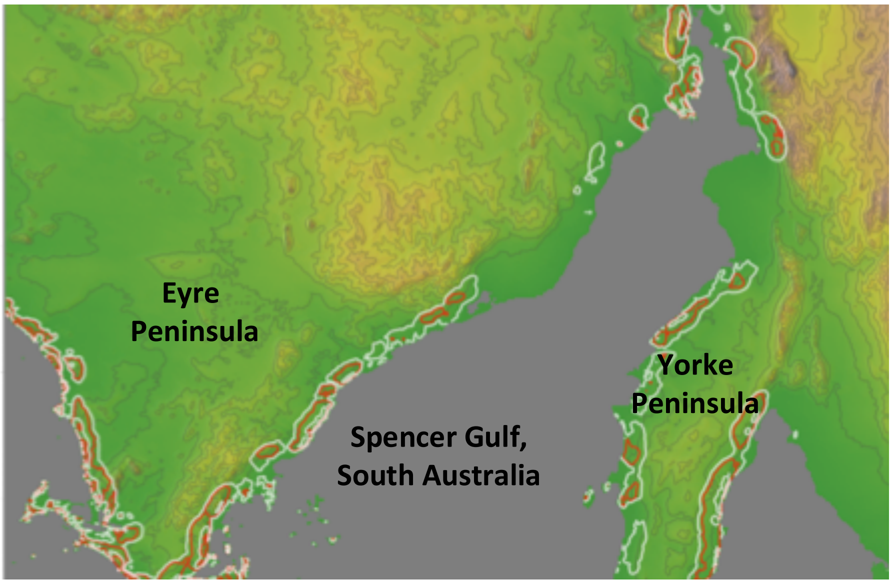


Figure 2: Potential PHES sites shown by red and white contour lines for the Spencer Gulf region of South Australia. (MEI)

This report also describes the results of MEI's economic analysis that explored the value new PHES facilities may have in today's Australian electricity markets.

MEI's energy arbitrage analysis looked back over the last nine financial years. Amongst all states in the National Electricity Market, the highest value was found in South Australia during the financial years 2007-08 and 2009-10 (see Figure 3). Arbitrage value has declined in more recent years possibly due to the lower incidence of heat waves that result in high electricity-price excursions.

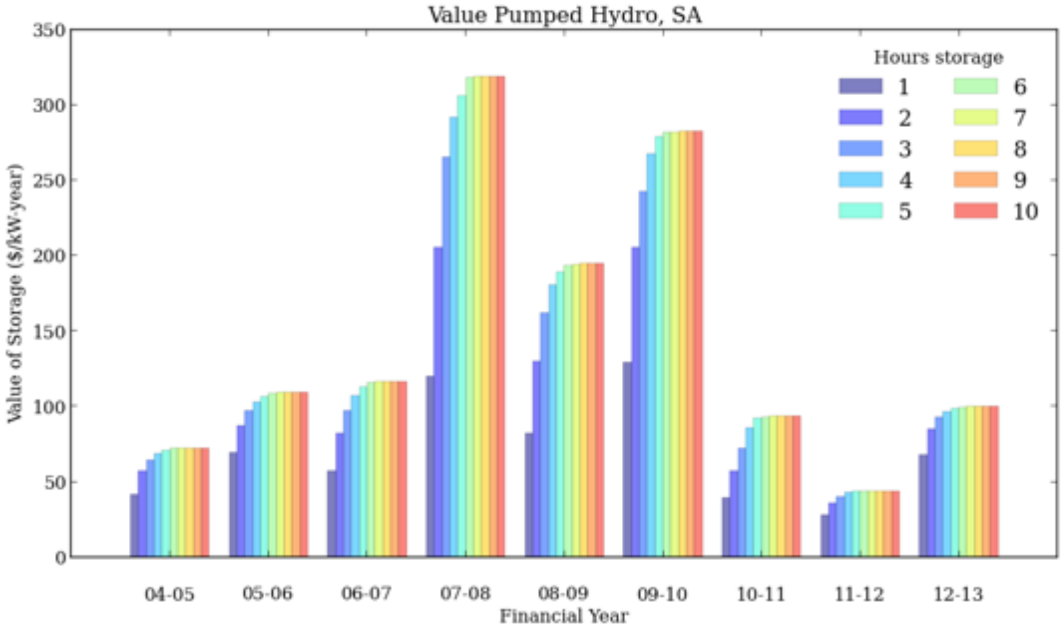


Figure 3: PHES arbitrage value index - by financial year and storage capacity, for South Australia. (MEI)

MEI calculated simple payback periods for new PHES facilities (excluding tax considerations). As shown in Figure 4, payback periods ranged from as low as eight years to over 25 years, depending on assumed costs and arbitrage value.

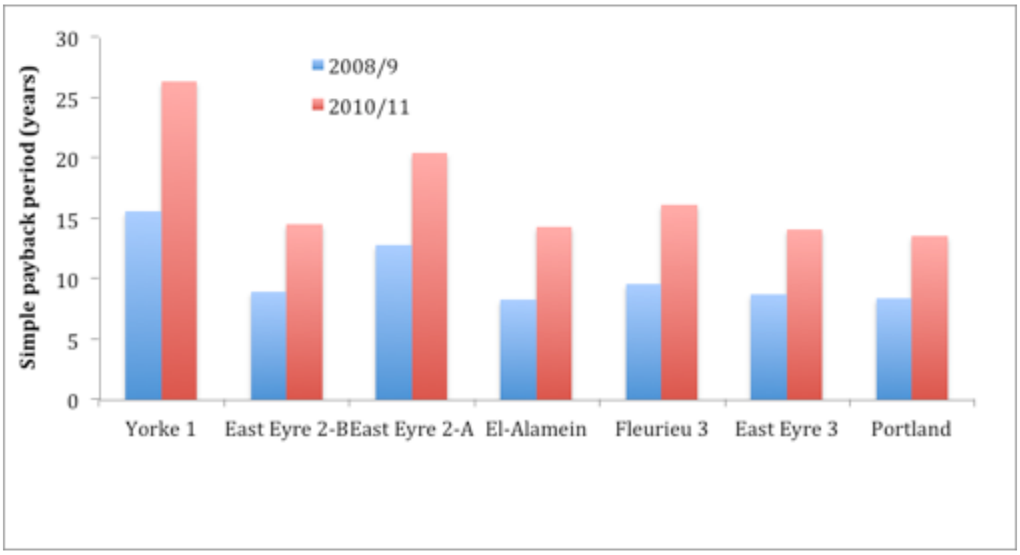


Figure 4: Simple payback period for PHES using actual electricity prices for the two-year period 2008 to 2009 and for the two-year period 2010 to 2011.

Further, MEI investigated the benefits of co-locating new PHES and wind generation in situations where there exists a fixed-capacity electricity transmission connection. No significant co-location benefits were found. Rather, limited electricity transmission capacity may be best used solely by wind generation at sites where the wind resource is good, and solely by PHES at sites suited for that technology.

Suggested future work required to progress the deployment of PHES in Australia and elsewhere include:

- further assessing seawater "turkey nest"-type PHES technology and the potential for modernisation
- working with local and overseas engineering, construction and equipment-supply firms to develop more accurate seawater PHES cost estimates
- applying MEI's terrain and cost-based mapping to other areas of Australia and the world
- developing representative cost-based PHES site identification
- investigating current and future-expected electricity transmission and grid-operation constraints in regions near potential PHES sites
- assessing PHES arbitrage value in Australian electricity markets, compared with overseas markets
- assessing the impact of different scales of new PHES deployment on wholesale energy prices, including the possibility of reducing price spikes caused by heat waves and other events
- assessing how PHES can provide grid-operation benefits and complement the expansion of renewable energy while obviating investment in electricity transmission and grid management infrastructure
- developing representative commercial project economic analysis.

2. Report outline

This report describes

- the current use of PHES globally and within Australia
- the literature that addresses future PHES applications and cost and economic return expectations
- MEI's PHES costing model
- MEI's site identification methodology that combines terrain mapping with the PHES costing model
- MEI's economic analysis of the application of PHES generally, and more specifically at example sites in South Australia and western Victoria
- possible future work.

3. PHES: the world's most-used method of energy storage

Pumped hydroelectricity energy storage (PHES) is by far the most significant form of large-scale energy storage used around the world. Figure 5 illustrates that the 127 GW of PHES installed makes up more than 99% of all electrical energy storage capacity. This far surpasses the existing capacity of other energy storage technologies such as compressed air, chemical batteries, or flywheels (Rastler 2012).

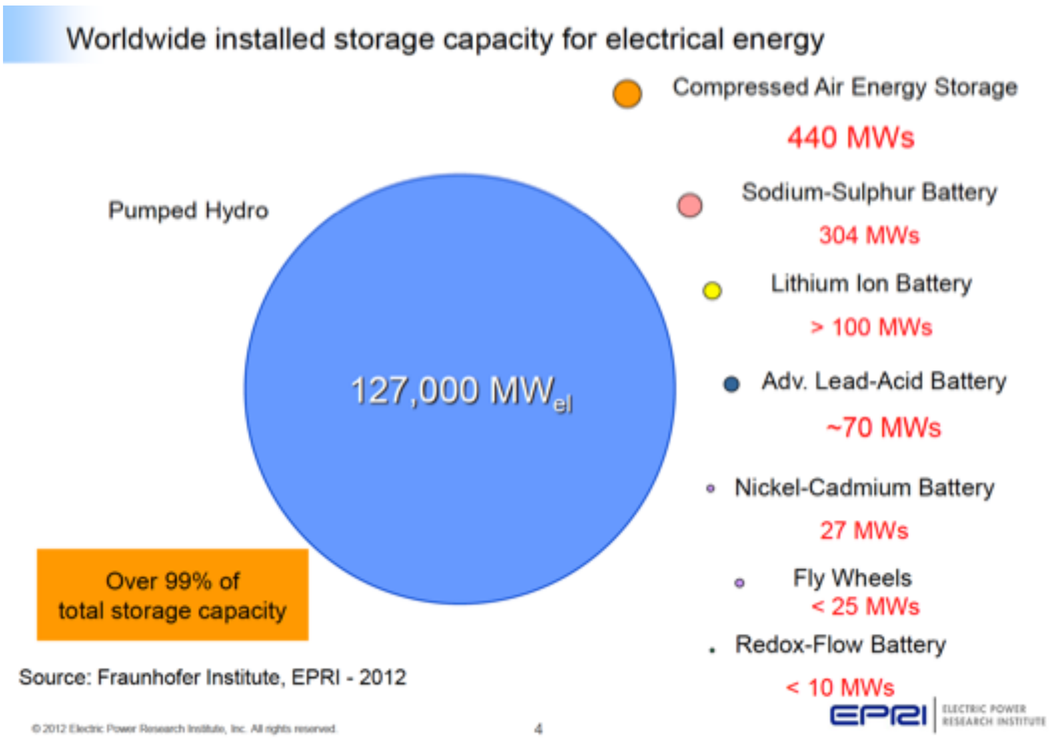


Figure 5: Worldwide installed storage capacity for electrical energy. (Rastler, 2012)

PHES was first used overseas in the 1890's. Since the 1960's, global PHES capacity expanded as a way to balance times of low and high electricity demand in grids with nuclear or coal-fired electricity generation facilities that operated at a constant load (NHA 2012).

Today, in grids with significant penetration of renewable energy technologies, PHES is increasingly being installed to balance times of low and high electricity supply from variable wind and solar-photovoltaic electricity generators and to assist grid frequency regulation and voltage support. In Europe, more than 10 GW of PHES is in the planning stage or under construction (IHA 2013). China is also very actively deploying PHES (Cheung 2011). Ten GW of PHES capacity is reported to be under construction in China including the 3.6 GW Hebei Province facility, which would become the world's largest (IHA 2013).

Brief explanation of PHES technology

As shown in Figure 6, PHES consists of water being pumped from a lower reservoir to a higher one. The water stored in the higher reservoir can later be used to generate hydroelectricity on demand. The reservoirs can either be largely natural or completely man-made, with various types of dams and construction techniques employed globally.

With PHES, no water is necessarily consumed or lost in the process of storing and generating energy, other than the water that evaporates or leaks from the upper and lower storage reservoirs and connecting pipes, tunnels, and channels. Therefore PHES does not necessarily require a continuous supply of make-up water. Nevertheless, often PHES is integrated with a conventional hydroelectric facility that does have a continuous or seasonal water supply (e.g. river or stream).

PHES uses equipment similar to conventional hydroelectricity, the main difference being the use of either reversible turbines or separate additional pumps.

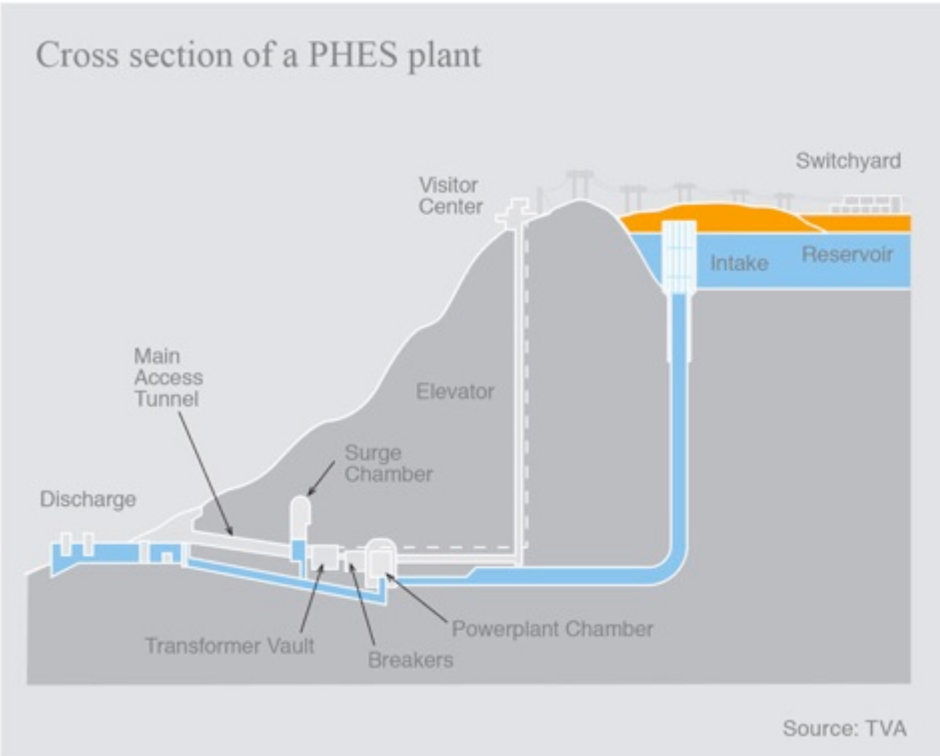


Figure 6: PHES facility simplified diagram. (TVA)

Key inter-related design parameters for PHES include:

- electricity generation capacity (i.e. turbine capacity)
- reservoir volumes
- the elevation difference (or net head) between upper and lower storage reservoirs
- amount of energy stored (which is a function of reservoir volume and net head)
- time period over which maximum electricity generation capacity can be maintained (which is a function of electricity generation capacity and amount of energy stored).

To illustrate the interaction of these design parameters, an upper reservoir filled with five million cubic metres of water, at an elevation 90 metres higher than a lower reservoir, contains approximately 1,000 MWh of potential energy. This reservoir of stored energy could be fitted to a 200 MW turbine and provide 5 hours of continuous electricity generation or fitted to a 100 MW turbine and provide 10 hours of generation. Were the reservoir described above 20 metres deep, it would cover 25 hectares.

Existing PHES facilities in Australia

Australia has 1,490 MW of PHES in operation (Geoscience Australia, 2010).

The largest PHES facilities in Australia include:

- Tumut-3, 600 MW electricity generation capacity, Snowy Mountains, New South Wales (see Figure 7), commissioned in 1973, integrated with conventional hydroelectricity generation at a facility with 1,500 MW capacity in total.
- Shoalhaven, 240 MW, southern New South Wales, commissioned in 1977.
- Wivenhoe, 500 MW, southern Queensland, commissioned in 1984.

Figure 7: Tumut-3 power station in the Snowy Mountains, Australia (EcoGeneration 2012).

PHES costs compared with other developing energy storage technologies

The Commonwealth Science and Industrial Research Organisation (CSIRO) developed cost estimates for energy storage methods (James-Hayward 2012) as input to the Australian Energy Market Operator's (AEMO's) modelling of 100 per cent renewable energy scenarios (AEMO 2013).

Figure 8 shows CSIRO's estimates of the levelised cost of electricity (LCOE) that can be delivered from various energy storage resources and technologies including PHES, chemical batteries, compressed air, molten salt heat storage, biogas, and biomass solids. The costs shown in Figure 4 are in 2012 Australian dollars but based on technology cost projections for 2030. As described later in this report (see Section 10) energy storage LCOE calculations are very sensitive to the assumptions made regarding how often the energy storage device is used or cycled (i.e. what capacity factor applies), and are also sensitive to the cost of the energy purchased to charge the energy storage facility.[1]

The energy storage technologies analysed by CSIRO have different applications relating to the length of time for which energy must be stored. The x-axis of Figure 8 shows storage times in a non-linear scale ranging from one hour to 30 days. On Figure 8, the LCOE values shown for PHES (based on ROAM 2012) range from approximately A$ 200/MWh to A$ 300/MWh and illustrate that PHES may be an economically competitive way to store energy for use over a time frame ranging from a few hours to one day.

Regarding other technologies depicted on Figure 8:

- Certain types of chemical batteries are projected to be more costly than PHES in 2030. However such chemical batteries may have the advantage of being better suited to shorter usage cycles than is practical for PHES.
- concentrating solar thermal (CST) energy storage with molten salt is projected as being potentially less costly than PHES by 2030.
- biomass and biogas are potentially the most economic options for longer-term storage (e.g. up to 30 days), such as might be needed in a 100 per cent renewable energy scenario.

Research and deployment underway globally aims at reducing the costs of energy storage. In particular, chemical batteries might become more competitive with PHES, especially where shorter cycle times apply.

[1] Other comparative metrics used in the energy storage industry include Levelised Cost of Capacity (LCOC). (Sandia 2013)

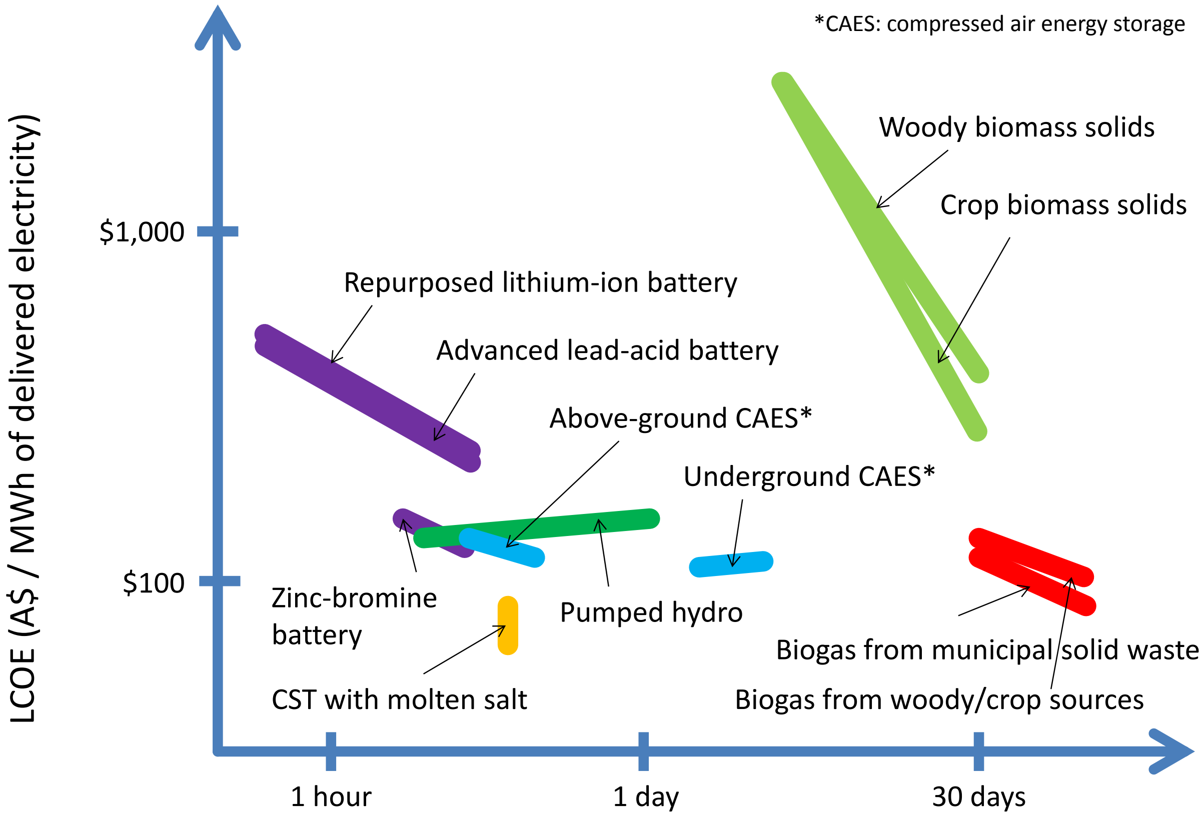


Figure 8: Levelised cost of electricity (LCOE) from various energy storage technologies; 2012 Australian dollars - based on technology cost projections for 2030. (James and Hayward, CSIRO, 2012)

4. “Turkey-nest” type dams for PHES use, freshwater and seawater

As shown in Figure 7 above, the Tumut PHES facility in New South Wales is of the “dammed-valley” type, where the natural contours of the land are used in conjunction with a dam to form a large water storage reservoir. However in situations where no suitable valleys are available, another type of often-used PHES reservoir is the “turkey-nest” type.

With the “turkey-nest” type of reservoir construction, the proportion of man-made artificial dam works are quite large compared to the use of natural contours and in some cases the man-made dam completely encircles the reservoir.

Table 1 lists and Figure 9 illustrates certain “turkey-nest” type PHES facilities from around the world. The electricity generation capacity of these “turkey-nest” type PHES facilities ranges from 30 to 1,872 MW (a difference factor of more than 60), while the amount of water stored ranges from 0.6 to 102 million cubic metres (a difference factor of more than 170).

Table 1: Examples of “turkey-nest” type pumped hydroelectricity energy storage facilities in operation around the world (list not exhaustive). (MEI)

Name	Location	Turbine size (MW)	Water storage (million m^3)	Year commissioned
Coo-Trois-Ponts	Belgium	1,164	8.5	1969
Seneca	Pennsylvania, USA	433	7.6	1970
Ludington	Michigan, USA	1,872	102	1973
Turlough Hill	Ireland	292	2.3	1974
La Muela	Spain	1,487	Not reported.	1989
Dlouhé Stráně	Czech Republic	650	2.7	1996
Tianhuangping	China	1,800	6.8	1997
Yanbaru	Okinawa, Japan	30	0.6	1999
Goldisthal	Germany	1,060	12	2004
Avce	Slovenia	185	2.2	2010
Taum Sauk	Missouri, USA	450	5.4	2010 (rebuilt)

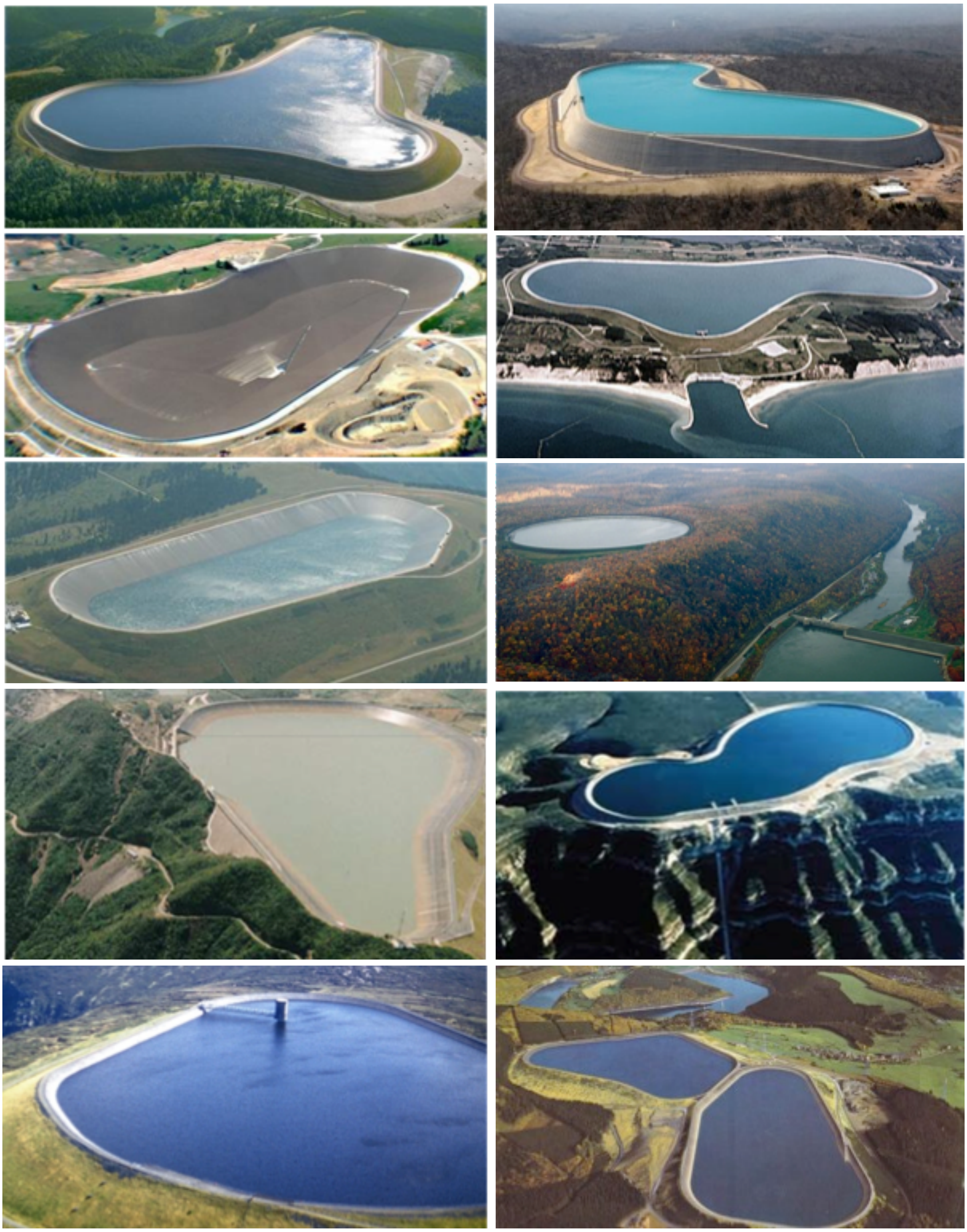


Figure 9: "Turkey nest" type PHES systems around the world. Anticlockwise from top left: Goldisthal, Avce, Dlouhé Stráně, Tianhuangping, Turlough Hill, Coo-Trois-Ponts, La Muela, Seneca, Ludington, Taum Sauk.

Given that Australia is a relatively flat continent and natural valleys are often classed as conservation areas, the “turkey-nest” type of dam is of particular interest for Australian applications.
The Bendeela Pondage of the Shoalhaven PHES facility (New South Wales) has characteristics of a “turkey-nest” type dam (see Figure 10) given that this reservoir does not occupy an obvious valley. Extensive dam walls have been constructed.

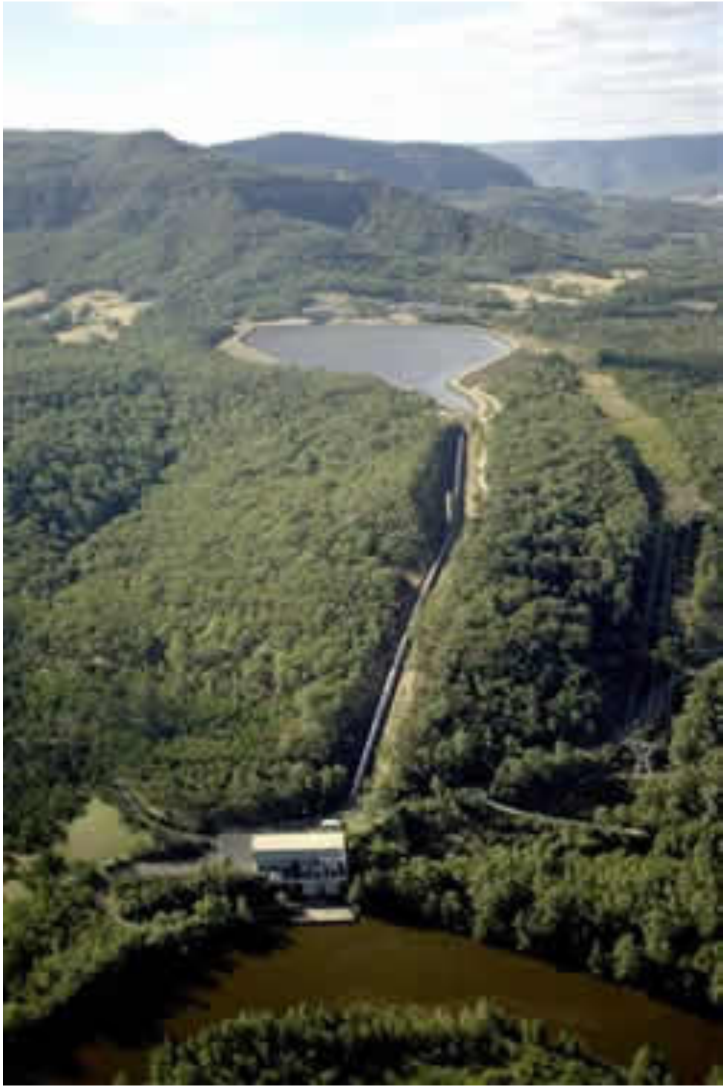


Figure 10: Shoalhaven Scheme - Bendeela Pondage. (Eraring Energy)

The Bendeela Pondage illustrates that though the traditional "dammed-valley" type of hydroelectricity reservoirs and completely artificial "turkey-nest" type dams sit at opposing design extremes, hybrids of the two designs exist. Another example of a hybrid design is the Raccoon Mountain facility in Tennessee, USA (see Figure 11).

The Raccoon Mountain facility has a storage capacity of 15 million cubic metres (36,000 MWh of stored energy) and is one of the largest PHES facilities in the USA (Sandia Corp., 2012). A dam wall has been constructed along approximately half of the perimeter of the upper reservoir, with the rest of the reservoir formed by the contours of the surrounding terrain.

Figure 11: Raccoon Mountain PHES upper reservoir (Tennessee, USA). (Google Earth, 2013)

Yanbaru “turkey-nest” type seawater PHES (Okinawa, Japan)

Amongst existing “turkey-nest” type PHES facilities relevant for Australian applications, of particular note is the Yanbaru PHES facility on the island of Okinawa, Japan (see Figure 12). Operating since 1999, it is the world’s first and only PHES plant to use seawater, with the ocean being used as the lower reservoir.

Coastal seawater PHES is being examined for Sonoma County California (US DOE 2013), and has also been studied for Hawaii, Ireland, and Latvia.

Figure 12: Yanbaru seawater PHES plant on Okinawa Island, Japan. (Renew Economy, 2013)

In May 2013, an MEI representative visited the Yanbaru power station as a guest of the owner J-Power. According to J-Power, the Yanbaru seawater PHES facility is fully functional and has operated trouble-free for 14 years. This first-of-a-kind facility was developed over a ten-year period of research, design and construction. Many technological measures were taken to address challenges specific to using seawater in a pumped hydro plant. These measures have proven successful. J-Power is confident that their design principles are sound and that a similar facility could be built at a much larger scale at a cost similar to freshwater PHES.

The Yanbaru PHES facility has a net head of 136 m. It has an effective working water storage volume of 564,000 m^3 and stores 188 MWh of energy. The octagonal embankment dam is 252 m across at its widest point. The reservoir is 23 metres deep and covers 5 hectares. The turbine capacity is 30 MW, of the reversible Francis-type.

The primary technical design challenges unique to using seawater include:

- corrosion
- the adhesion of marine organisms to system components that would thereby impede efficient water flows
- environmental protection considerations.

The pump / turbine is constructed of austenitic stainless steel for high corrosion resistance against seawater. This is weaker than other grades of steel, and according to J-Power would not be suitable for net head greater than 400 metres.

Corrosion and fouling resistance in pipework is addressed by using fibreglass-reinforced plastic for the penstock, and reinforced concrete with anti-fouling coating for the tailrace tunnel. Cathodic protection was used for other steel components such as the draft gate and upper reservoir intake. Vinyl ester paint and ceramic seals have been used elsewhere. J-Power advised that the after 14 years of operation, the measures outlined above have successfully met their expectations for resistance to corrosion and adhesion of marine organisms.

The earth-embankment dam is lined with ethylene-propylene-diene monomer (EPDM) rubber. Underneath the rubber lining is a 50 cm-thick gravel drainage layer, cushioned with polyester fabric to protect against sharp edges. There is no concrete or asphalt lining. This rubber lining has successfully withstood violent tropical storms and typhoons. (See Figures 13 and 14.)

The drainage layer has a system of seawater sensors and pressure gauges. In the event of a leak, seawater would collect at a central point and be pumped back into the reservoir, while the sensors would indicate the leak location for ease of repair. This, along with significant revegetation and fencing systems to prevent animals from entering the facility, is an example of the local environmental protection measures taken.

Figure 13: Photo of upper reservoir of Yanbaru PHES plant. (MEI)

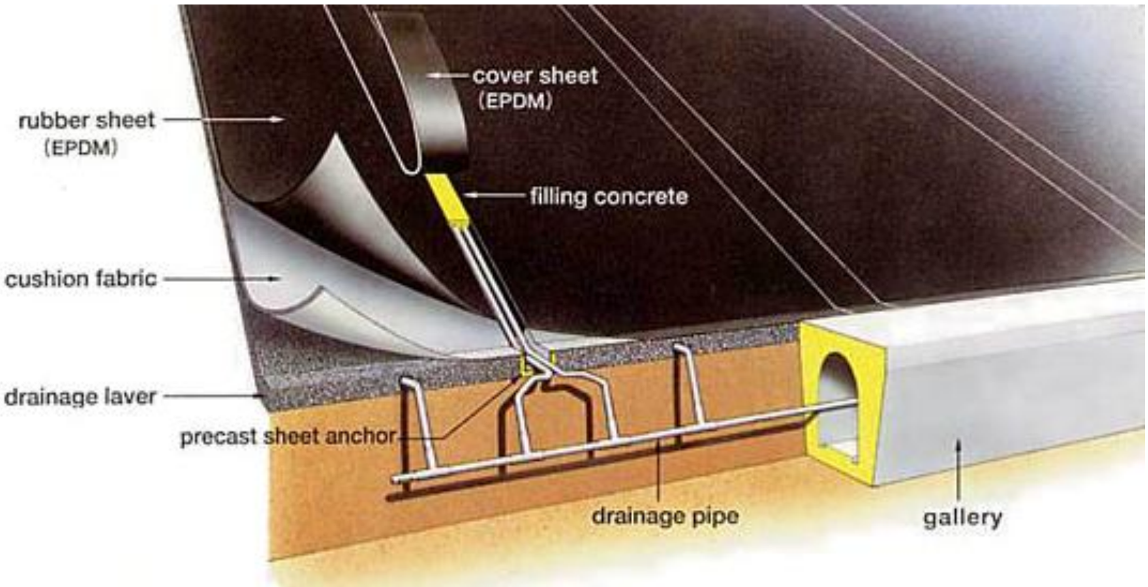


Figure 14: Diagram of lining used in reservoir at Yanbaru seawater PHES facility. (J-Power)

5. Literature review - PHES site identification studies

The economic viability of PHES systems depends strongly upon finding locations with suitable geographic characteristics. A number of studies in the literature have used graphical information systems (GIS) to search, at a high-level, for potential PHES reservoir locations around the world. The net head (i.e. elevation difference) between the upper and lower reservoirs is a key search variable. Also, because the cost of building reservoirs is significant, most studies have based their searches around existing reservoirs that can be used as either the upper or lower reservoir.

The literature describes terrain searches for both "dammed-valley" and "turkey-nest" type PHES sites.

Knight Piésold 2010 study for British Columbia, Canada

A study for BC Hydro over the south-west of the Canadian province of British Columbia (Knight Piésold, 2010) described a GIS-based search for new PHES sites. Given British Columbia's mountainous terrain, this study identified a large number of potential sites even while considering only reservoirs capable of storing at least 3,000 MWh of electrical energy on Vancouver Island and at least 6,000 MWh of electrical energy for sites on the British Columbian mainland.

The type of PHES studied and/or identified included:

- pairs of existing lakes that lie within five kilometres of each other
- increasing the capacity of one or two existing lakes that lie within 5 km of each other
- building new dams across a valley that lies within 5 km of an existing reservoir
- building new "turkey-nest" type dams at a site that lies within 5 km of an existing reservoir
- building new seawater reservoirs near the ocean (either valley or "turkey-nest" type)
- using active or abandoned underground mines as lower reservoirs.

Searching was performed using both an automated GIS-based tool, and visual inspection for suitable valleys. The key search parameters were elevation, existing reservoir surface area, and proximity of potential reservoirs. Results were filtered for various environmental and planning constraints. Excluded, for example, were nature reserves and salmon-bearing rivers.

Knight Piésold identified 194 potential sites within the cost brackets defined by the study. Example sites are shown in Figure 15.

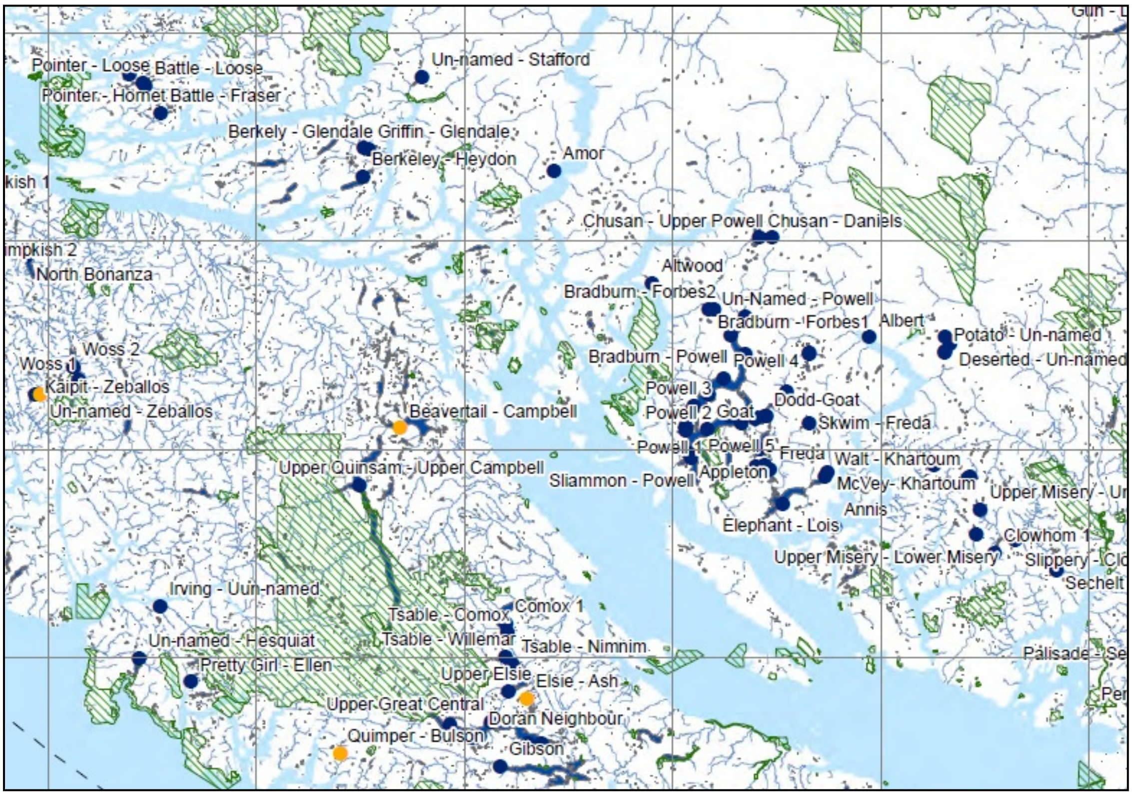


Figure 15: Map showing some potential PHES sites in British Columbia, Canada. (Knight Piésold 2010)

Connolly 2010 PHES site identification study for Ireland

There is a range of PHES literature from the Republic of Ireland, where increasing wind penetrations are raising the profile of energy storage.

Connolly et al., (2010) developed a computer program to analyse 10-metre resolution digital-terrain-model elevation data. This program searched for circular areas within desired net head and horizontal distance parameters and took the step of estimating earth-moving volumes required to create a flat surface (see Figure 16), such that a “turkey-nest” type dam could be built.

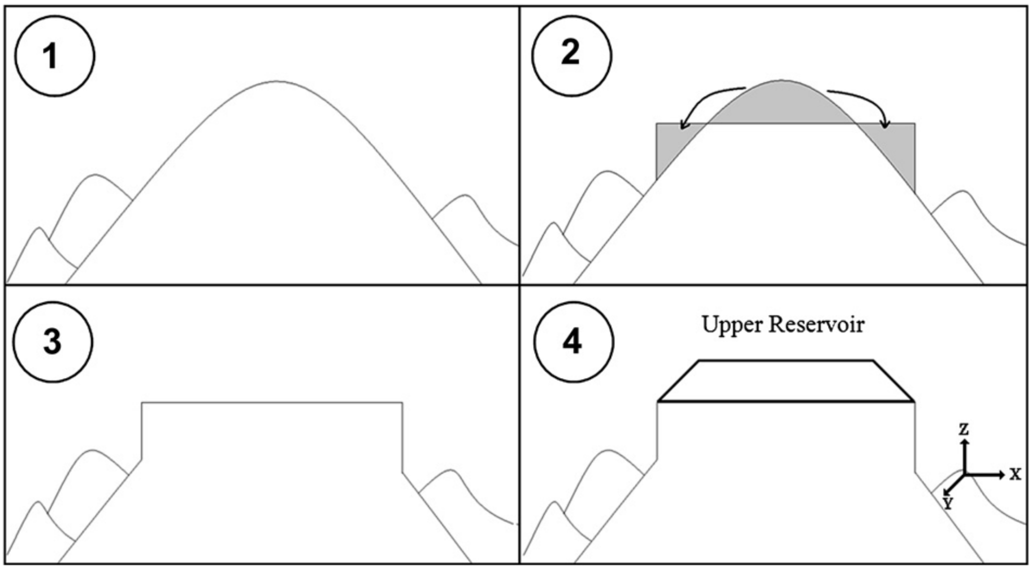


Figure 16: Earth-moving procedure used to calculate flatness of PHES sites. (Connolly et al. 2010)

The earth-moving algorithm was iterated on a very large number of possible circular sites across the study area. Prior filtering steps were based on proximity to potential lower reservoirs, and above a suitable elevation. Hence the program was computationally heavy and had to be distributed over eight Windows XP workstations to perform the analysis over a 20 x 40 km area.

MEI notes that this style of analysing flatness is potentially very useful for searching for potential PHES sites; however it may be worthwhile investigating further prior filtering steps and simplifications to reduce the computing time.

The analysis in Connolly et al. (2010) was able to replicate the identification of an existing “turkey-nest” PHES site (Turlough Hill) with remarkable accuracy. Overall it identified a further five potential sites in the 20 x 40 km study area, which represents approximately one per cent of the total area of the island of Ireland.

PHES site identification studies for Australia

This section describes studies in the literature that identified PHES sites in Australia.

Hessami-Bowly (2010), Portland Victoria

Hessami and Bowly identified seawater PHES sites near Portland in western Victoria that might be integrated with wind-generated electricity.

Blakers (2010), central Tasmania and the Araluen Valley, NSW

Blakers et al. developed a GIS-based analysis that specifically searched for sites suitable for "turkey-nest" type dams, looking primarily at elevation and horizontal distance between reservoirs, without constraining the analysis to existing reservoirs or valleys. The results for two small geographic areas, central Tasmania and the Araluen Valley in New South Wales, indicate a large number of sites with suitable terrain. However the analysis did not progress to costing nor did it apply constraints regarding competing land-use.

Worley (2011), Eyre Peninsula, South Australia

The engineering firms Worley Parsons and SKM MMA identified sites on the Eyre Peninsula in South Australia that may be suitable for seawater PHES.

Blakers (2012), northern Australia

Blakers et al. identified the potential for very-large scale PHES sites in northern Australia that might be used to assist the export of renewable electricity from Australia to neighbouring Asian countries.

ROAM (2012), NEM region of Australia

In 2012, ROAM Consulting was contracted to search for potential PHES sites that might be applied in the Australian Energy Market Operator's modelling of 100 per cent renewable energy scenarios (AEMO 2013). ROAM's work covered the National Electricity Market (NEM) region that extends from South Australia to far north Queensland

As primary inputs, ROAM's analysis used 30-metre-resolution digital elevation data, a 30m x 30m resolution "water mask" (which determines the smallest existing water body that would be found by the search algorithm), and a 1km x 1km-resolution land-use database. The analysis searched for sites within 3.5 kilometres of at least one existing water body, where the elevation difference between the upper and lower pond was greater than 90 metres of net head. The sites were identified by local elevation minima where a reservoir could be created with a single dam wall, essentially damming an existing valley. Three pre-defined dam wall heights of 30, 60 and 90 metres were analysed.

From over 100,000 sites initially identified, ROAM's cost-based search methodology resulted in 68 sites being selected for detailed analysis. Of these sites, 53 were freshwater and 15 were seawater. Many of the identified sites are in land-use areas classed as 'nature conservation', indicating that these sites may eventually be judged unsuitable due to environmental and societal considerations.

ROAM's methodology precluded searching for "turkey-nest" type dam sites because of possible greater environmental impact and cost and because the number of identified sites needed to be kept to a tractable number. In other words, opening up the ROAM study to include turkey-nest-suitable flat terrain would have resulted in a very large number of additional sites being identified (i.e. >> 100,000 sites) and this was seen as being far beyond the needs of the 100 per cent renewable energy study.

Sustainable Energy Now 2013 - Western Australia

Sustainable Energy Now suggested that suitable seawater PHES sites exist near Albany and Geraldton in Western Australia. PHES facilities might also be established using existing freshwater dams near Perth.

6. Literature review - PHES costs and costing methods

There is a range of literature that has sought to provide insight or review into the cost of PHES systems.

The capital costs of PHES systems are often compared using one or preferably both of the following parameters:

1. the power component: capital costs divided by the turbine power electricity generation capacity, in units such as $-capital/kW
2. the energy component: capital costs divided by the amount of energy stored in one full charge, in units such as $-capital/MWh.

Knowledge of the amount of energy stored at a PHES facility allows conversion from the first parameter above to the second.

Alvarado-Ancieta review of electrical and mechanical costs

Alvarado-Ancieta (2009) compiled a database containing the electrical and mechanical (E&M) costs only for more than 80 recent conventional hydroelectricity projects (not PHES projects). The cost data include the full range of conventional hydroelectricity turbine designs with net heads ranging from less than 100 metres to 800 metres.

The cost data display a strong relationship between turbine power capacity and cost, and a weaker relationship between net head and cost. MEI's use of this data is described in Section 8.

Deane, P. et al, University College, Cork Ireland

Deane et al. (2010) reviewed the status and costs of existing and proposed PHES projects in the USA, Europe and Japan. These projects ranged from new systems to extensions or repowering of existing systems.

The capital costs of 14 proposed projects ranged from € 470/kW to € 2,170/kW (2010 currency). Using an exchange rate of 1.3 €/A$, this equates to a range of approximately A$ 600/kW to A$ 2,800/kW.

This reference did not include sufficient information to inform capital cost per unit of energy stored.

Knight Piésold costs for PHES in British Columbia, Canada

Knight Piésold (2010) reported cost estimates for the individual PHES sites identified in British Columbia, Canada. Their costs were based on experience from other projects and some budget quote information. Construction-financing costs were included.

In this study, capital costs per generation capacity ranged from C$ 1,300/kW to C$ 3,300/kW. (Note, MEI's study assumes a 1:1 C$:A$ currency exchange rate.)

Figure 17 shows the estimated capital costs per unit of energy stored for each potential PHES site identified by Knight Piésold, plotted versus reservoir storage capacity. For most sites, capital costs per unit of stored energy range from C$ 200,000 to C$ 500,000/MWh.

The series "Lake" refers to sites where traditional dams could be used at existing valleys. The series "ManMade" refers to "turkey-nest" type dams. Figure 17 shows that the capital costs of the "ManMade" series overlap with the "Lake" series, indicating that there was no significant cost difference between the two dam types seen in this analysis.

Knight Piésold differentiated between seawater and freshwater sites but indicated an average cost difference of only one to two per cent.

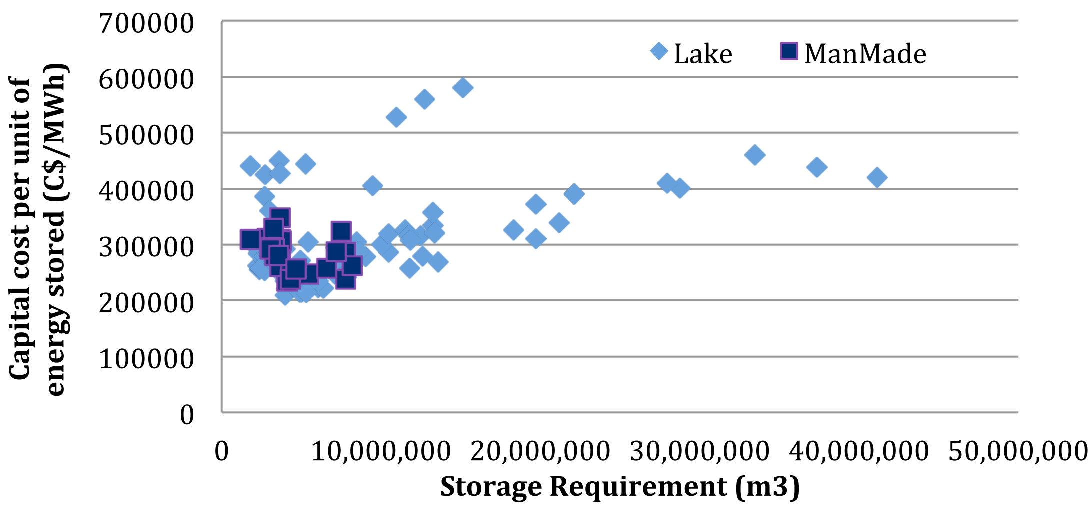


Figure 17: Estimated capital cost of energy stored for various potential PHES sites in British Columbia, Canada. (Knight Piésold 2010)

Rastler, Electric Power Research Institute (USA) PHES cost review

Rastler (2010) of the US-based Electric Power Research Institute (EPRI) reviewed electricity energy storage technology costs. PHES costs are reported as ranging form US$ 1,500/kW to US$ 4,300/kW and from US$ 250,000/MWh to US$ 430,000 MWh. The estimates are based on “technology assessments, discussions with vendors and utilities, and experience” with operating systems.

Worley Parsons and SKM MMA PHES cost review for South Australia

The engineering firm Worley Parsons (2011) with SKM MMA applied capital costs ranging from US$ 1,500/kW to US$ 2,000/kW. The lower end of the cost range was applied to sites with net head of 200 metres.

Augustine, National Renewable Energy Laboratory (USA) PHES cost review

Augustine et al. (2012) with the USA’s National Renewable Energy Laboratory (NREL) reviewed PHES capital cost estimates from several sources and refer to two cost points being US$ 1,500/kW and US$ 2,000/kW.

This reference did not include sufficient information to inform capital cost per unit of energy stored.

Steffen, University of Duisberg-Essen PHES cost review

Steffen (2012) identified 12 new PHES projects in Germany, reporting costs in the range of € 800/kW to € 1,400/kW. This equates to a range of approximately A$ 1,000/kW to A$ 1,800/kW. The majority of the projects had generation capacities within the range of 200 to 600 MW and involved building at least one new reservoir.

This reference did not include sufficient information to inform capital cost per unit of energy stored.

Black and Veatch PHES cost review for NREL

In a study for NREL, Black & Veatch (2012) estimated the "bottom-up" capital costs for a 500 MW PHES facility with 10 hours of storage (stored energy of 5,000 MWh) to be US$ 2,230/kW (+/- 50%) and US$ 223,000/MWh. These costs were based on a confidential in-house reference study.

Figure 18 presents a breakdown of Black and Veatch's results in 2012 US dollars.

Some of Black & Veatch's technical assumptions include the following:

- the distance from the upper to the lower reservoir was set at 610 metres
- a circular dam was specified with a wall height of 30 metres
- dam construction material was roller compacted concrete (RCC) with costs set at US$ 200/m^3
- the cost for electricity generation equipment and balance of plant was set at US$ 750/kW
- tunnelling costs were set at US$ 60 million for 1,272 metres of 6.1 metre diameter tunnels (including access tunnels), corresponding to approximately US$ 100 million/km-of-horizontal-reservoir-separation
- a factor of 5%-of-construction-cost was set for design and project management support
- a factor of 5%-of-construction-cost was set for construction management and start-up
- 15% contingency was applied.

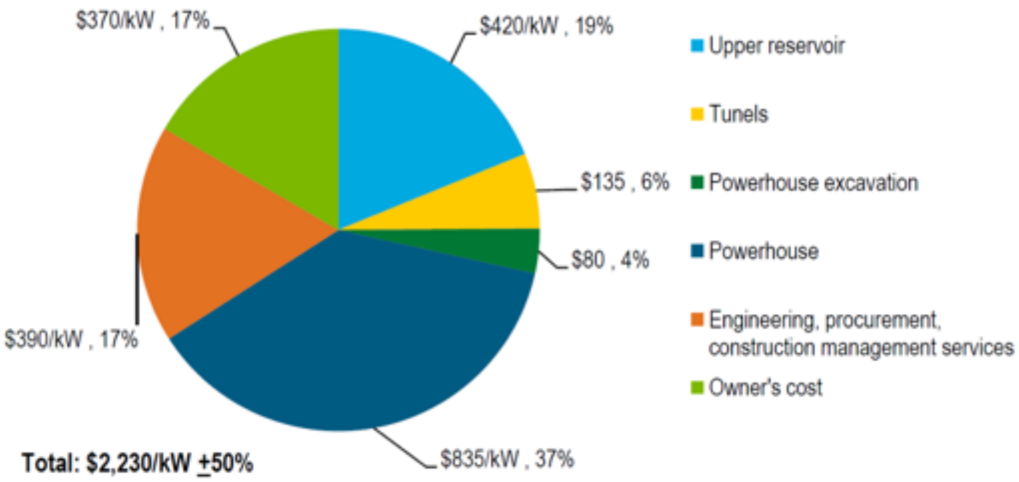


Figure 18: Cost breakdown for a new 500 MW, 5,000 MWh PHES facility in 2012 US dollars. (Black & Veatch, 2012)

ROAM costing of PHES sites for the NEM-region of Australia

ROAM (2012) studied potential PHES sites in the NEM-region of Australia that was used as input to AEMO's 100 per cent renewable energy scenario modelling (AEMO 2013) assumed simple high-level cost parameters for 500 MW PHES facilities in order to match literature cost benchmarks.

ROAM produced costs for 68 PHES sites. A cost curve for the 38 lowest-cost PHES sites is given as Figure 19. Estimated capital costs per-unit-of-energy-stored at these sites range from A$ 100,000/MWh to A$ 1,000,000/MWh.

Given that ROAM set the electricity generation capacity of each site at 500 MW regardless of reservoir size or net head, capital costs per-unit-of-electricity-generated fall over a wide range, from A$ 3,000/kW to A$ 12,000/kW.

The total amount of energy storage possible at the 68 sites identified by ROAM is 516 GWh. Given that the average demand of the NEM region is 25 GW, this means the identified storage could meet the average needs of the NEM for over 20 hours. However, AEMO's final modelled 100 per cent renewable energy solutions for the target years 2030 and 2050 (AEMO 2013) did not include any _new_ PHES facilities. This was because AEMO found PHES to be too expensive (based on ROAM's estimated costs) relative to the projected 2030 and 2050 costs for other energy storage technologies options such as molten salt heat energy storage (for shorter-term storage), and biomass/biogas (for longer-term storage).

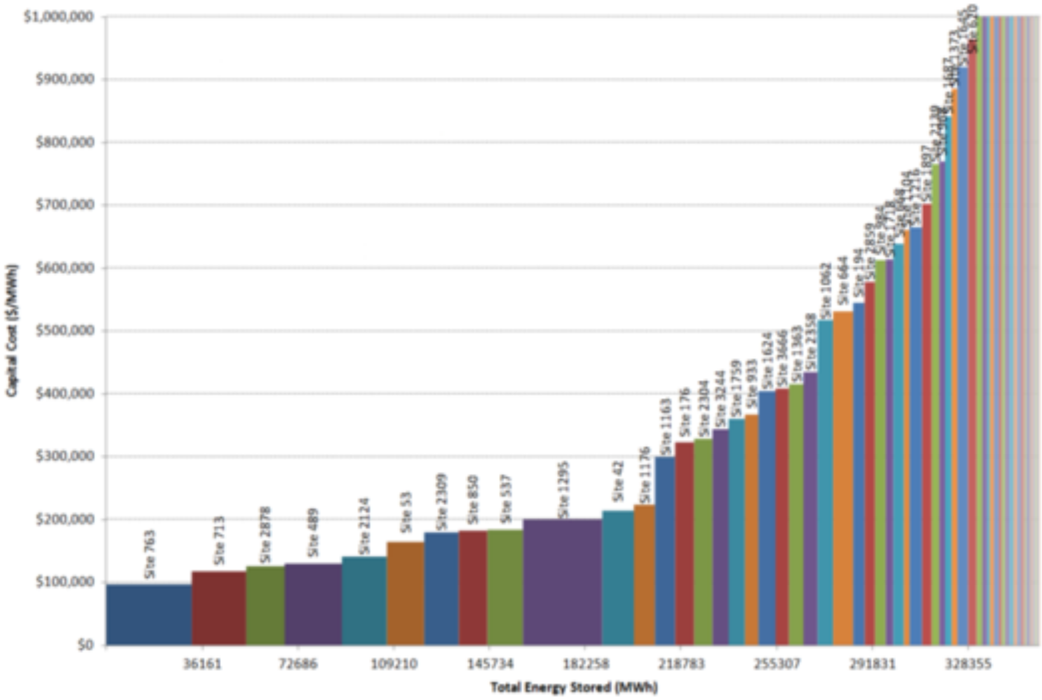


Figure 19: Cost curve of shortlisted PHES sites, in A$ 2012. (ROAM 2012)

MEI comparison of literature PHES costs

Figure 20 compares PHES capital costs from the literature in terms of capital cost per unit of electricity generation capacity (A$/kW) while Figure 21 compares these in terms of capital cost per unit of energy stored (A$/MWh).

Figure 20 shows that the capital costs per unit of electricity generation capacity (A$/kW) from Deane et al. (2010), Knight Piésold (2010), Rastler (2010), Worley (2011), Augustine et al. (2012), Steffen (2012), and Black and Veatch (2012) range from A$ 600/kW to A$ 4,300/kW.

The figures from ROAM (2012) range as high as A$ 12,000/kW. One reason for this large range is because ROAM set the electricity generation capacity of all PHES facilities to 500 MW regardless of reservoir size or net head.

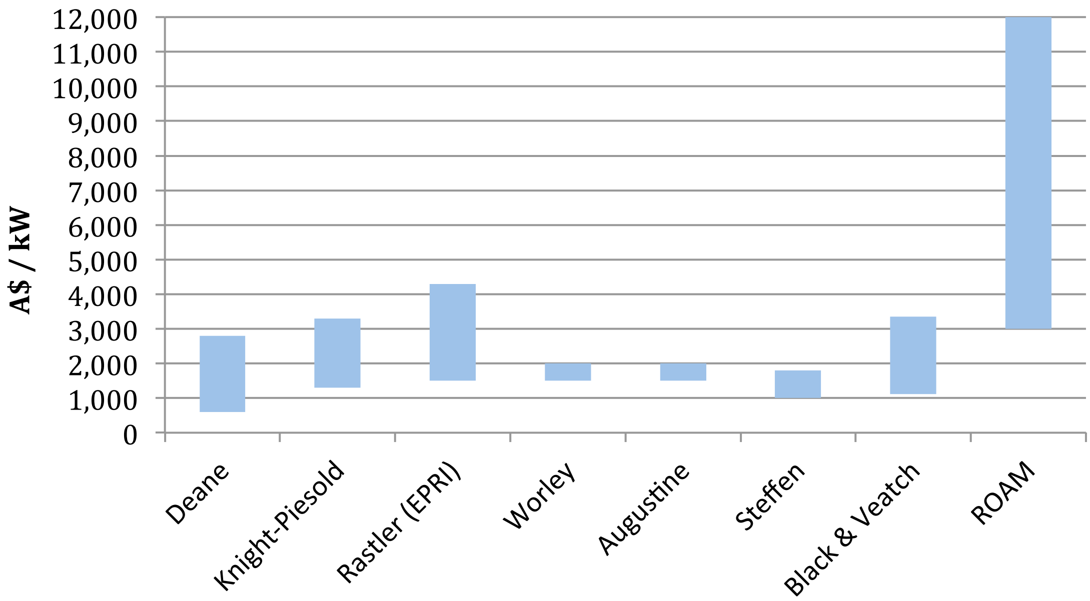


Figure 20: Comparison of literature PHES capital costs per unit of electricity generation capacity (A$/kW). (MEI)

Figure 21 shows that the capital costs per unit of energy stored (A$/MWh) from Knight Piésold (2010), Rastler (2010) and Black and Veatch (2012) range from approximately A$ 100,000/MWh to A$ 500,000/MWh.

The lowest-cost sites from ROAM (2012) also cost approximately A$ 100,000/MWh. However, ROAM's most-expensive sites cost more than A$ 1,000,000/MWh. This is because ROAM exhaustively tabulated dammed-valley sites even if their maximum storage capacity was small.

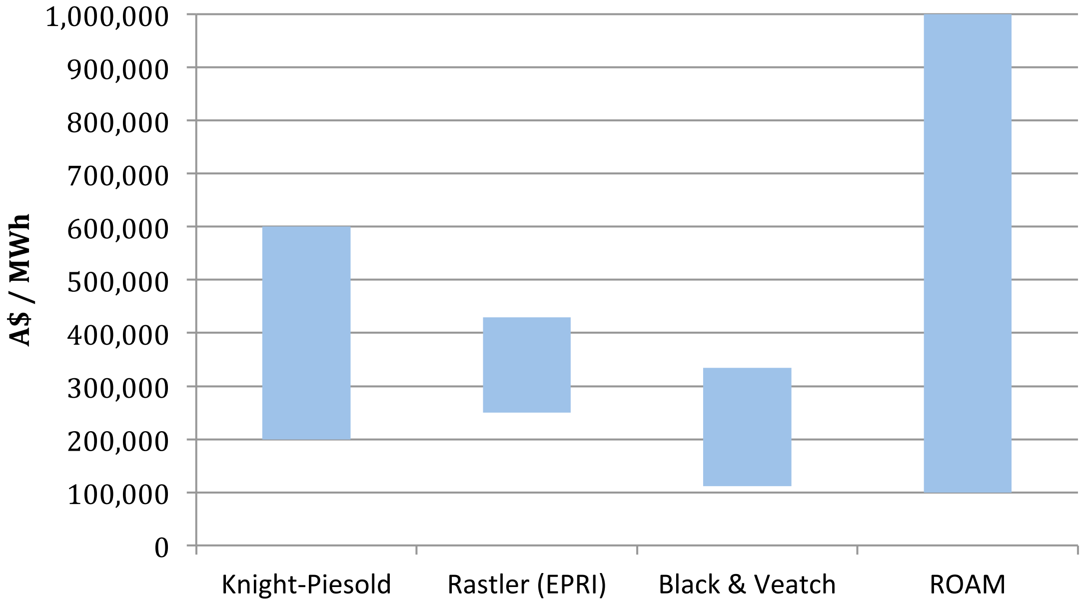


Figure 21: Comparison of literature PHES capital costs per unit of energy stored (A$/MWh). (MEI)

7. Literature review - Economic and grid-operation benefits of PHES

In recent decades PHES has been used to balance times of low and high demand in electricity grids that have constantly-loaded nuclear or coal-fired electricity generation. However, for today's rapidly-evolving electricity grids, PHES can also be used to:

- balance out times of low and high electricity supply from variable renewable energy sources such as wind and solar-photovoltaic

and

- assist grid frequency regulation and voltage support.

These benefits might apply especially where renewable energy sources are located on the fringes of a constrained electricity grid (AEMO 2013b, Marchment Hill 2012).

As the proportion of supply to the electricity grid from variable renewable energy increases, the variability of electricity prices might also increase. Therefore, the balancing characteristics of PHES might become more valuable.

This section describes certain studies, found in the literature, that investigate the economic and grid-operation benefits specifically of PHES, especially including those that feature wind as a variable renewable energy supply source.

Irish electricity grid (Connolly et al. 2012)

Connolly et al. (2012) modelled high penetrations of wind-generated electricity and PHES in Ireland, concluding that adding PHES could allow significantly increased wind penetration in the grid.

In the case of 'single' PHES systems, with a single penstock and reversible turbine, storage enabled a wind penetration increase from 30% to 60%. In the case of 'double' PHES systems, which have a separate pump and turbine and penstock for each to enable simultaneous pumping and dispatch, wind penetrations of almost 100% were found to be feasible.

This study included economic trade-offs. However because a system-wide model was used that assessed least-cost performance of the entire grid in which storage was one part, this study did not refer to the value of individual storage systems.

The annual demand of the Irish energy system modelled (based on a projection to 2020) was 30 TWh/yr (82 GWh/day average). As shown in Figure 22, 50 GWh of stored energy would enable 65% wind penetration in the Irish electricity grid, whereas 500 GWh of stored energy was required in order to achieve 100% wind penetration.

This study did not investigate the impacts of adding other forms of renewable energy into the simulation.

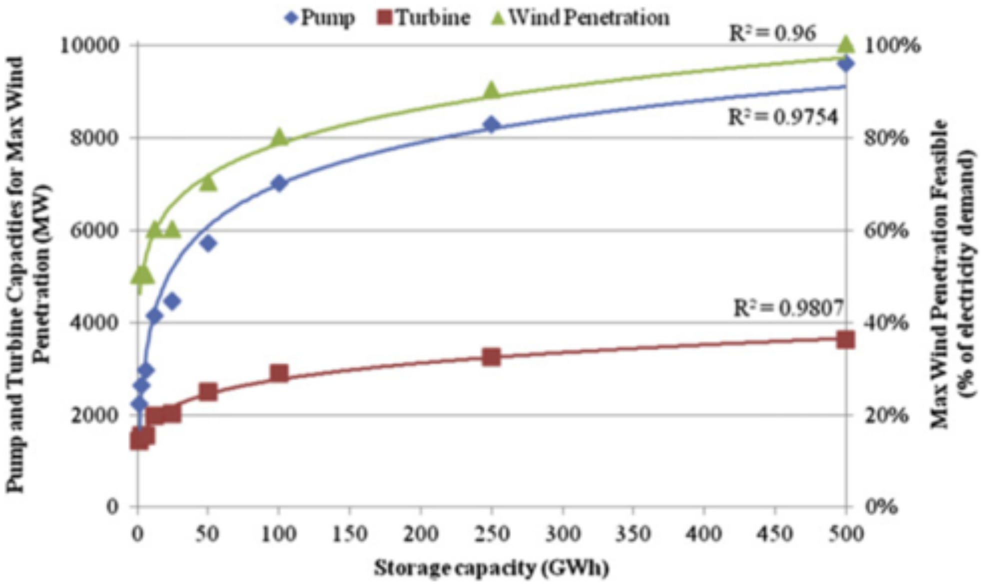


Figure 22: Results of modelling the increased penetration of wind and PHES in a 2020 Irish electricity grid. (Connolly et al., 2012)

Portland Victoria, Australia (Hessami-Bowly 2010)

Hessami and Bowly (2010) identified that a seawater PHES facility located near the wind farms in the Portland area of western Victoria, Australia with capacity to store 1,800 MWh of energy and generate electricity at a rate of 188 MW would produce an economic rate of return of 9.6%.

Eyre Peninsula, South Australia (Worley 2011)

Worley Parsons and SKM MMA (2011) identified sites on the Eyre Peninsula in South Australia that may be suitable for seawater PHES used in combination with wind farms. Economic returns greater than 46% were reported in some cases.

8. MEI PHES costing model

This section describes details of the MEI's PHES costing model, which includes the following individual PHES system components:

- reservoir
- piping / tunnelling
- electrical and mechanical, including pumps and turbines.

MEI's costing model is able to reflect cost factors such as:

- horizontal and vertical distances between reservoirs
- size of water storage volume
- dam construction type
- dam geometry
- turbine/pump capacity and configuration,

but is not able to reflect other site-specific cost factors such as:

- geology
- environmental constraints.

Following the presentation of MEI cost model details in Section 8, Section 9 then marries this cost model with MEI's site selection tool and presents the resulting costs for several PHES sites.

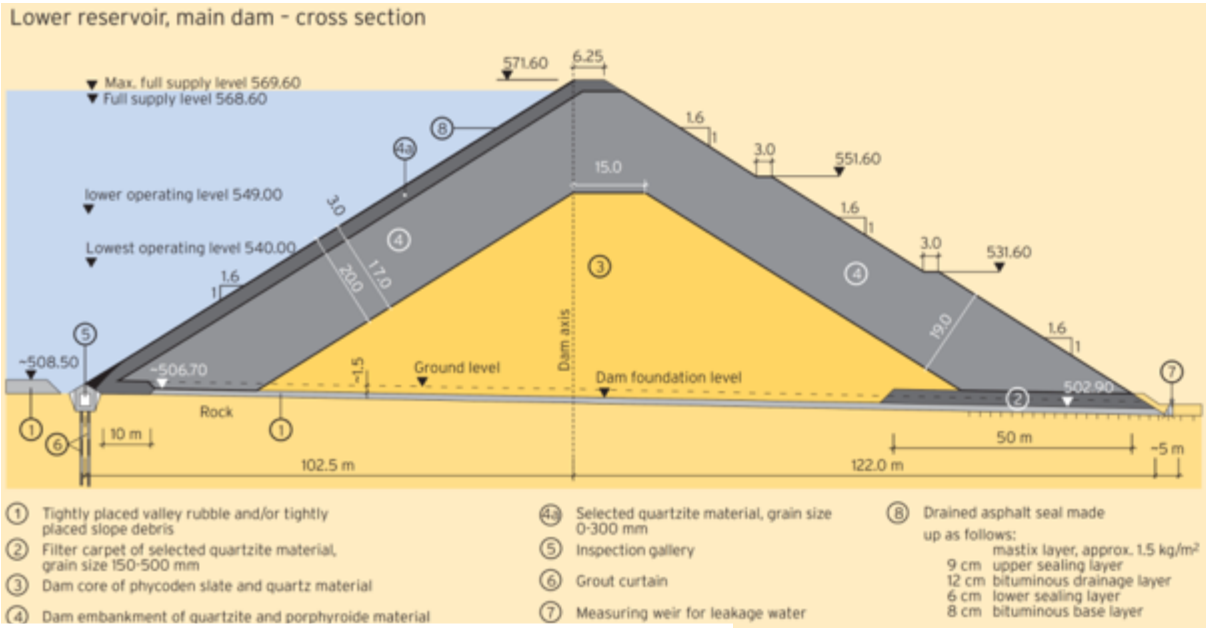
MEI reservoir cost model

MEI developed costing models for the following dam construction types:

- lined earth-embankment-type dam
- roller-compacted concrete (RCC) type dam.

Lined earth-embankment dam costing model

Most of the "turkey-nest" type dams identified in Table 1 and Figure 9 are lined earth-embankment-type dams. Design details for the Goldisthal, Germany facility are depicted in Figure 23. Lined earth-embankment dams consist of an inner core of earth and/or rock lined on the inner (reservoir) side with a sealing layer of concrete or asphalt.



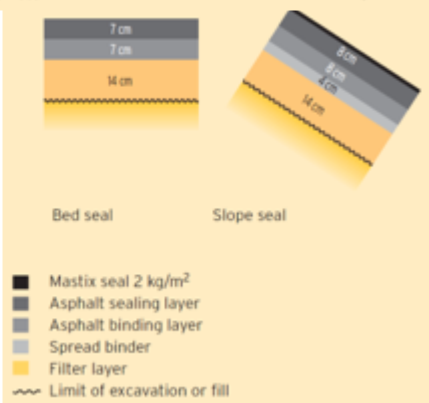


Figure 23: Cross section of dam construction, Goldisthal, Germany PHES facility. (Vattenfall Europe, 2003)

For the earth-embankment reservoir construction type, a simplified costing model was developed based on the following assumptions:

- the reservoir is circular, with a cross-sectional design as shown in Figure 24.
- the reservoir is excavated, and the same volume of excavated material is used to create an embankment dam around the perimeter (slope of 1.3:1).
- the ground is level (i.e. the effect of flattening ground or taking advantage of pre-existing slopes or contours is ignored).
- inner surface of the reservoir is lined at an assumed cost of A$ 60/m^2.
- earthworks costs are A$ 17/m^3 of material excavated.
- total reservoir depth is 30 metres.

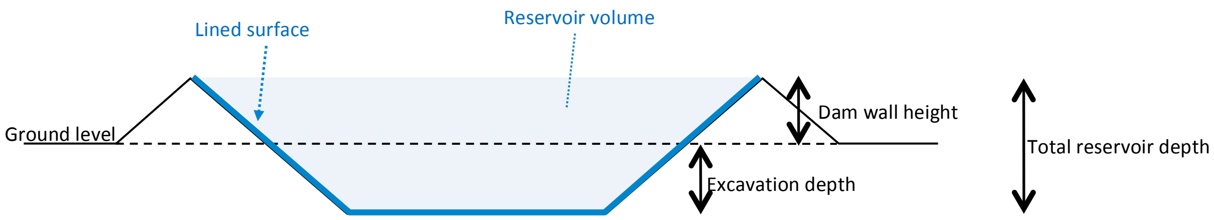


Figure 24 Cross-sectional design of earth-embankment-type reservoir for MEI costing model.

For any given desired reservoir volume, there is potentially a trade-off to be made between reservoir depth and width (i.e. a narrow, deep reservoir versus a wide, shallow reservoir). However, MEI found (as shown in Figure 25) that the total reservoir cost for earth-embankment-type dams is insensitive to depth at depths greater than 30 metres. Therefore this study assumed 30 metres depth for all earth-embankment-type dams. The reason for this insensitivity is described next.

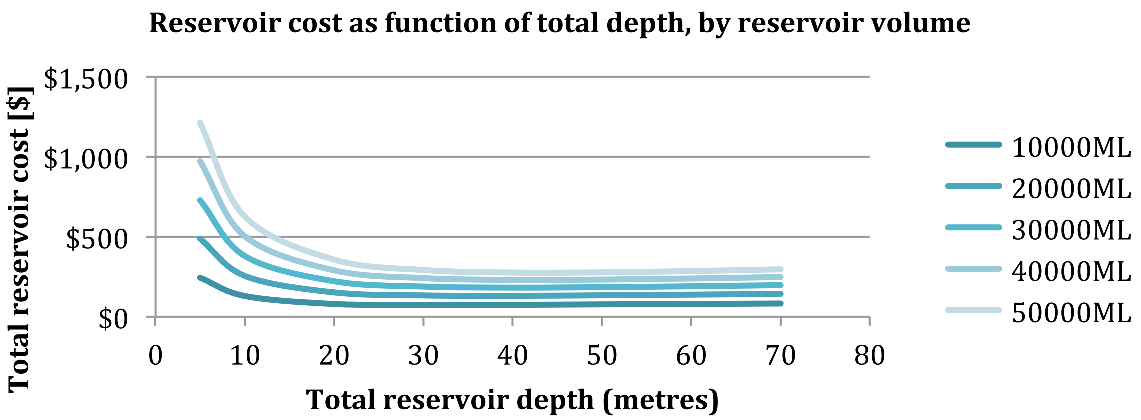


Figure 25: Earthworks plus lining costs for an earth-embankment-type reservoir as a function of depth. (MEI)

The relative insensitivity of total reservoir cost to reservoir depth is likely because the reservoir lining cost becomes the dominant cost factor with increasing volume. Figure 26 illustrates the relative lining-versus-earthworks costs with increasing reservoir volume (for a constant reservoir depth of 30 metres). This conclusion might change with different assumptions about the costs of lining versus the costs of earthworks.

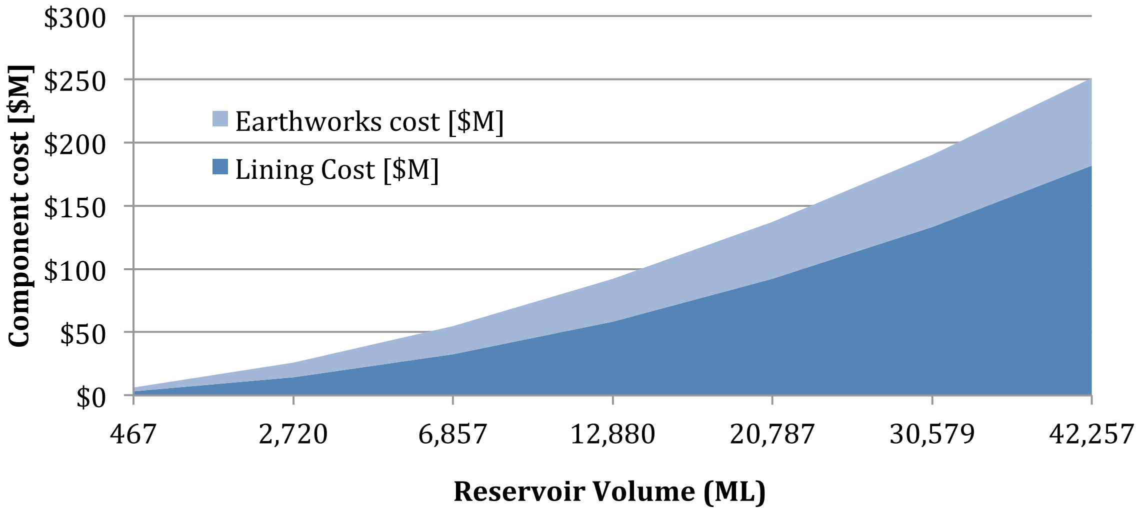


Figure 26: Earth-embankment-type dam component costs as a function of reservoir volume. A\$ 60 m^2 assumed for lining cost. (MEI)

Based on geometry and unit cost assumptions, earth-embankment-type dam costs for a large range of reservoir sizes were generated.

The following empirical formula was then derived where reservoir cost (earthworks plus lining cost) is described as a function of reservoir volume only:

$$C_R = 141\ V^{0.818}$$

where: C_R = *reservoir cost (\$M)* V = *reservoir volume* (m^3).

To aid the reader in conceptualising the earth-embankment-type reservoirs modelled, other characteristics are displayed in Figures 27 through 29.

Figure 27 shows that creation of a reservoir with a water storage volume of, for example, 20,000 megalitres (ML) (i.e. 20 million m^3) would require the excavation of approximately 2.7 million m^3 of earth. In this example, the outer diameter of the dam wall would be just over 1,000 metres.

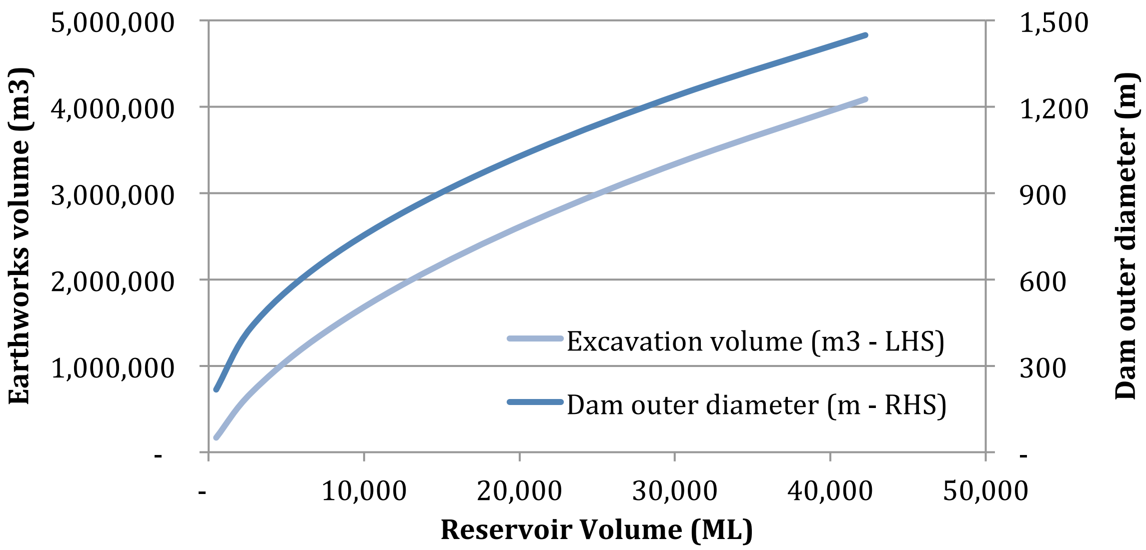


Figure 27: Earth-embankment-type reservoir dimensions as a function of reservoir volume. LHS axis shows excavation volume. RHS axis shows dam outer diameter. (MEI)

Figure 28 shows that to create a 20,000 megalitre (ML) reservoir (20 million m^3) with the reservoir depth set at 30 metres, the optimum excavation depth would be four metres. The earth-embankment dam wall would be 26 metres high.

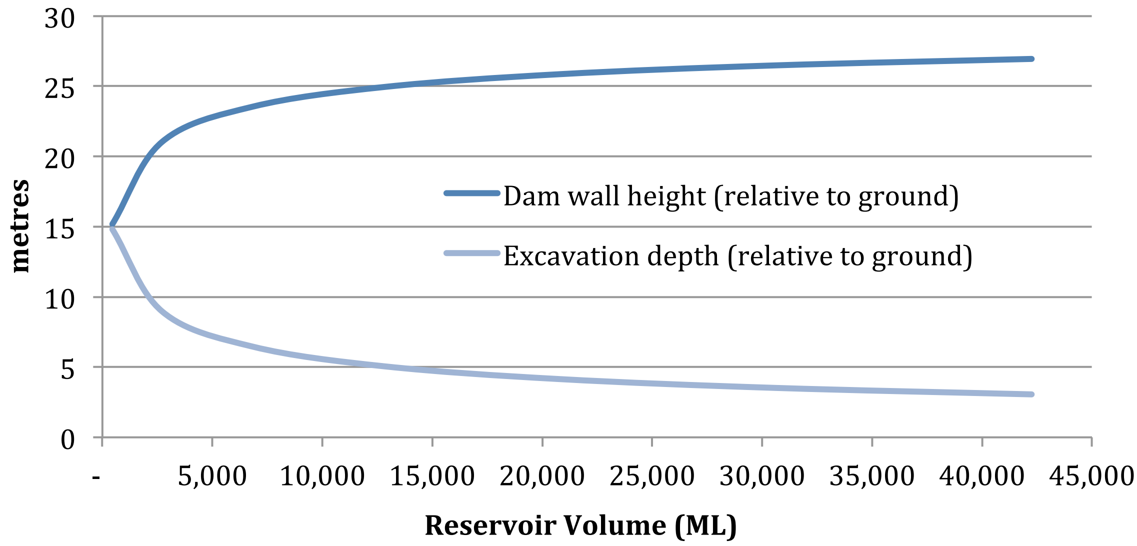


Figure 28: Dam wall and excavation dimensions changing with reservoir volume. Constant total depth = 30m. (MEI)

Figure 29 shows that, as an example, at 100 metres of net head between the upper and lower reservoirs, approximately 5,000 ML (five million m^3) of active water volume is required to store 1,000 MWh of energy.

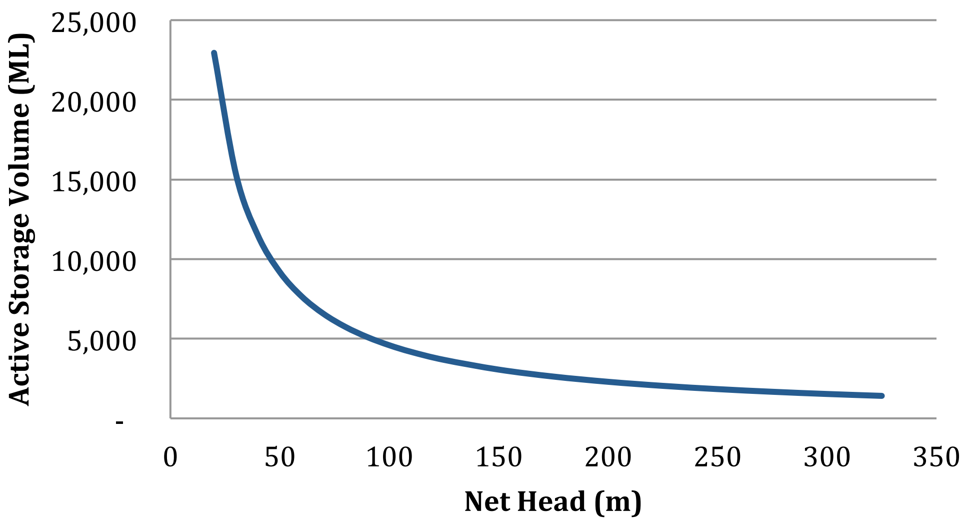


Figure 29: Relationship between water volume requirements as a function of net head between reservoirs, for 1,000 MWh of stored energy. (MEI)

Lower-cost HDPE-lined earth-embankment-type dam

MEI's research partner Arup provided information about the costs of an earth-embankment-type dam in northwest Victoria used for saline water evaporation. The lining employed at that dam is a sheet of high-density polyethylene (HDPE). While the lining and associated costs for a larger seawater reservoir might be greater than the costs of a simpler HDPE liner, this provides a useful benchmark.

Roller-compacted concrete (RCC) dam costing model

The roller-compacted concrete (RCC) type dam construction uses a mixture of cement, fly ash, water, sand, aggregate and additives that contains much less water than normal concrete. RCC is placed in a manner similar to paving. The material is delivered by dump trucks or conveyors, spread by small bulldozers or specially modified asphalt pavers, and then compacted by vibratory rollers.

The Taum Sauk PHES facility in the USA was rebuilt with RCC (see Figure 30) after the previous earth-embankment-type dam failed due to overtopping. Taum Sauk is reported to be the largest RCC-type dam in North America.

Figure 30: Taum Sauk PHES dam under reconstruction with roller-compacted concrete. (KTrimble, 2009)

The following assumptions are applied to the modelling:

- the walls and floor of the dam consist of RCC.
- the reservoir is circular.
- the inner wall of the dam is vertical (water area is independent of water level).
- the dam wall vertical cross-sectional area is trapezoidal with a constant angle (θ) on the outer slope (as shown in Figure 31).
- the dam wall base thickness (b) is a constant proportion of the dam wall height (h_d).
- the dam is built on perfectly flat ground.

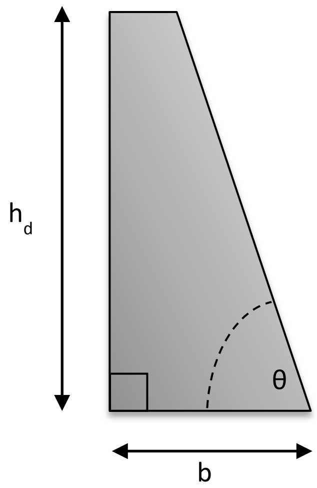


Figure 31: Cross-sectional design of RCC-type dam for costing model. (MEI)

The reservoir construction cost is given by:

$$C_R = C_{Wall} + C_{Floor}$$

$$C_R = \lambda_\pi \lambda_\theta V^{0.5} h_d^{1.5} + \frac{\lambda_F V}{h_d} \dots\dots\dots\dots\dots\dots (3a)$$

Where for ease of calculation and understanding, many numbers and values assumed to remain constant for this analysis have been condensed into the lambda values.

$$\lambda_\pi = \frac{\sqrt{4000\pi}}{2\times10^6} \qquad \lambda_\theta = U_{RCC}\left(2\tau_b - \frac{1}{\tan\theta}\right) \qquad \lambda_F = \frac{t_f U_{RCC}}{1000}$$

Where:

- C_R = reservoir cost, (A$ million)
- C_{Wall} = dam wall cost, (A$ million)
- C_{Floor} = dam floor cost, (A$ million)
- V = dam volume, (ML)
- h_d = dam wall height, (m)
- U_{RCC} = unit cost of roller-compacted concrete ($/m^3), assumed to be A$ 200/m^3.
- τ_b = ratio of dam base thickness to dam height (ratio), assumed to be 0.7.
- θ = outer dam wall angle, assumed to be 74^o.
- t_f = dam floor thickness (m), assumed to be 0.5 metres.

The dam wall height is optimised using the partial derivative of equation 3a:

$$h_{d,opt} = \left(\frac{\lambda_F}{\lambda_\pi \lambda_\theta} V^{0.5}\right)^{0.4} \dots\dots\dots\dots\dots\dots\dots (3b)$$

Reservoir-finishing costs

Beyond the basic costs of excavation and lining, there are additional reservoir-finishing costs. These include outlet structures and spillways. If seawater is being used, then drainage and pumping systems such as those deployed in the Yanbaru plant might be required.

Details of these reservoir-finishing costs are difficult to obtain. Therefore, based on the methodology used by Black & Veatch (2012), a 50% premium has been applied to the base reservoir excavation and lining costs.

MEI reservoir costing results

Figure 32 compares three different types of reservoirs for which MEI developed costing models. Costs rank from highest to lowest as follows:

- roller compacted concrete (RCC)
- earth-embankment-type dam with lining assumed to cost A$ 60/m^2
- earth-embankment-type dam with lining assumed to cost A$ 15/m^2.

The middle result, earth-embankment-type dams with lining assumed to cost A$ 60/m^2 was used in the balance of this report unless otherwise stated.

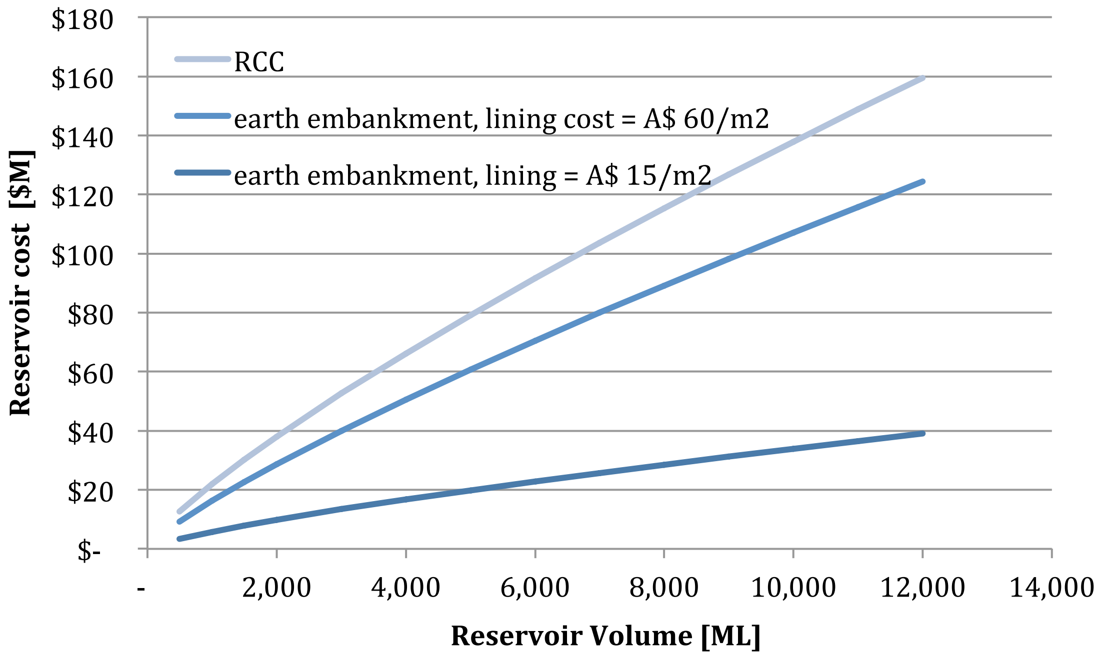


Figure 32: Cost comparison of three types of dam construction modelled. (MEI)

MEI piping / tunnelling cost assumptions

Depending on the local topography and other considerations, upper and lower PHES dams can be connected by tunnels or by potentially cheaper above-ground piping and penstocks.

As shown in Figure 7, the Tumut PHES facility employs above-ground penstocks for the whole length, a distance of approximately 500 metres. Other Australian examples of surface-penstocks on steep slopes include:

- the Poatina power station in Tasmania, which has a 1.65 km penstock down a slope greater than 55% in sections (Hydro Tasmania, 2013a)
- the Wilmot power station, which has a 380 metre penstock down a slope that reaches 70% (Hydro Tasmania, 2013b, Google Earth).

The cost of piping / tunnelling is one of the variables with the greatest level of uncertainty. In the key literature references, ROAM's assumed cost for piping / tunnelling of A$ 500 million/km (ROAM 2012) is five times greater than the A$ 100 million/km figure derived from Black & Veatch (2012), assuming that one US$ equals one A$. ROAM set their cost parameters to deliver project costs that were consistent with other references. Black & Veatch's costs are based on a confidential in-house reference study.

More detail on the cost of piping / tunnelling has proven difficult to find, but useful for comparison purposes are the unit costs reported used in a recent feasibility study on constructing new high-speed rail lines in Australia (AECOM Australia Pty Ltd, 2011). Based on a review of recent transport projects, this assumes values of A$ 96 million/km for twin 8.5-metre diameter rail tunnels in rural areas, and A$ 180 million/km in urban areas. These cover civil works costs for tunnelling and preparation but do not include rail-specific components.

As another comparison, the recently completed North-South water supply pipeline in Victoria cost A$ 750 million for 70 kilometres of 1.7-metre diameter above-ground pipe. This translates to A$ 10.7 million/km, although obviously the different pipe diameter would be a major factor affecting costs, as are the actual purpose and operational requirements of this water pipeline.

Based on the references, a cost of A$ 100 million/km has been assumed for tunnelled pipeline while for surface piping, a cost of A$ 10 million/km has been used as a lower bound estimate. Piping / tunnelling costs are therefore assumed to be independent of the pumping and/or electricity generation capacity of a given PHES facility.

As no detailed information on piping / tunnelling costs was found in the literature, MEI did not calculate PHES flowrate requirements and pipeline diameters.

MEI electrical and mechanical components cost model

In developing a cost model for electrical and mechanical (E&M) components, MEI used the data from Alvarado-Ancieta (2009) and then introduced a function of both electric power generation capacity and net head similar to that suggested in Ogayar and Vidal (2009). This gave a reasonable approximation of the raw Alvarado-Ancieta data, as shown in Figure 33.

The calculated results in that chart are given by the formula

$$C_{em} = 3.3657 \times P^{0.891} \times H^{-0.336},$$

where C_{em} is the E&M capital costs (US$ million), P is power (MW) and H is net head (m).

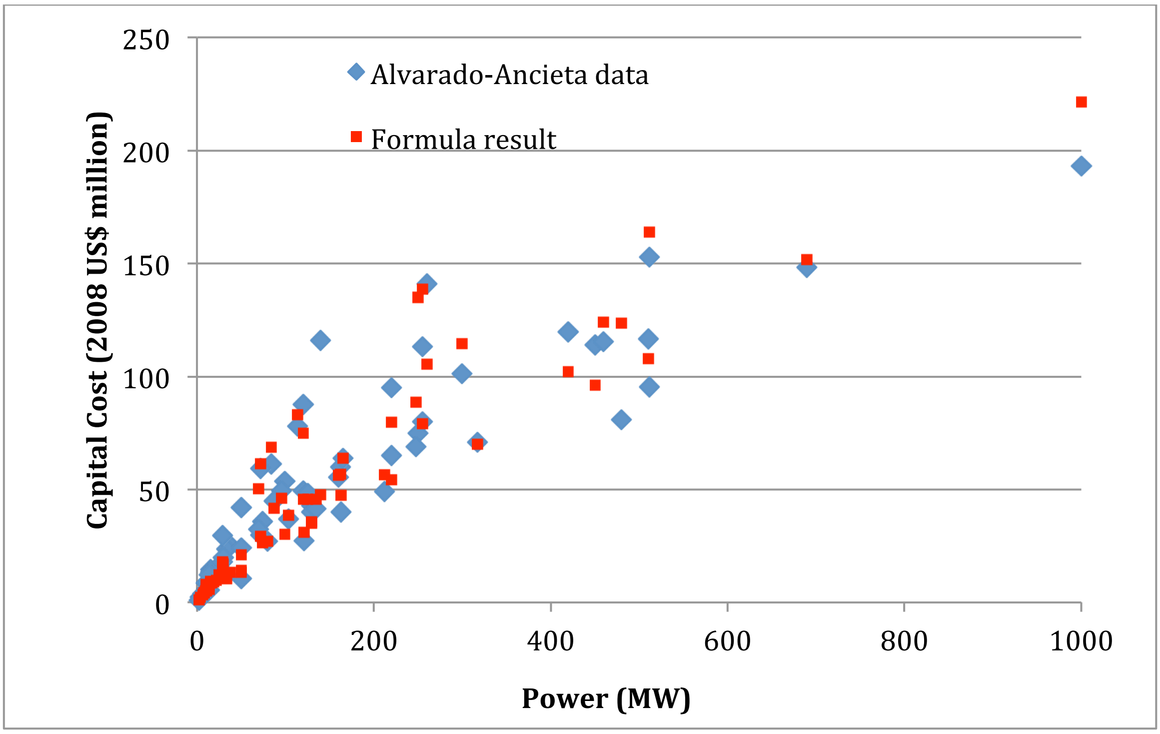


Figure 33: Alvarado-Ancieta PHES E&M costs (US$ million, 2008) compared with results from MEI costing model equation. (MEI)

The data from Alvarado-Ancieta refers only to conventional hydroelectric projects.

For PHES projects with net heads lower than 100 metres, Kaplan turbines would likely be used. These are not reversible and would require a separate pump.

For PHES projects with net heads of around 100 metres and greater, reversible Francis turbines can be used.

While MEI recognise that the use of reversible Francis turbines or parallel turbine/pump arrangements in PHES facilities will result in higher costs than those that apply to the conventional hydroelectricity projects that were the basis of the Alvarado-Ancieta work, no reliable information was found that could be used to determine the cost premium for PHES equipment. Likewise, no information is available about the costs of austenitic stainless steel materials that may be required for use with seawater.

In the absence of such information, a premium of 50% has been applied to the electrical and mechanical equipment costs for the seawater PHES facilities that are the focus of this study versus those reported by Alvarado-Ancieta for conventional hydroelectricity facilities. This is a significant assumption that should be further investigated.

Indirect costs

MEI consider the reservoir, piping / tunnelling, and electrical and mechanical costs to be direct costs.

The following indirect costs are then added:

- engineering, procurement and management (EPC): 10% of direct costs.
- contingency: 20% of direct costs
- owner's costs: 20% of direct costs.

Further cost investigation needed

To improve the cost estimates presented in this study, further investigation is needed regarding:

- requirements for lining reservoirs
- design conditions and costs for piping and tunnelling
- updating the costs modelled here with recent and Australia-specific data.

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9. MEI PHES site identification using terrain and costing model

This section describes MEI's PHES site selection tool, which marries topographical mapping information with the cost model described in the previous section. This section then presents location and cost details for example PHES sites in South Australia and Victoria.

Methodology

In order to easily identify potential PHES sites across large land areas, MEI applied the costing model (outlined in the previous section) to a elevation topography data set. This allowed MEI to examine the trade-off between the cost of building a reservoir closer to, or further from the coast, and at higher or lower elevations.

For terrain mapping, MEI used one-arcsecond (30 metre) shuttle radar topography mission (SRTM) elevation data from Geoscience Australia (Gallant, 2011).

For each 30m x 30m pixel, the total dam infrastructure cost (the capital cost of the reservoir plus piping / tunnelling) was calculated, based on the horizontal and vertical (elevation) distance from the ocean.

As was shown in Figure 29, for a fixed amount of stored energy, the volume of stored water that is required decreases dramatically as the elevation difference between the two reservoirs is increased. Therefore, the higher the elevation at the selected inland reservoir site, the less is the construction cost required per unit of stored energy. However, the cost of piping / tunnelling is also a significant component of system costs. Taking both cost components into account, MEI's analysis can compare the costs of:

- a low-net-head, large-volume reservoir close to the coast

versus

- a high-net-head, small-volume reservoir situated far from the coast,

as well as combinations in between.

The cost of electrical and mechanical equipment is not included in this comparison because those costs are assumed not to vary with height or distance.

MEI seawater PHES site cost comparison results

This section describes the results of MEI's combined cost and terrain site analysis and identification for seawater PHES facilities.

This study focused on regions in South Australia and western Victoria because these regions are home to the greatest concentration of wind farms in Australia. Over half of the electricity generated in South Australia often comes from wind (Renew Economy 2012). Also, these regions are located on the far western end of the sometimes-constrained eastern states' electricity grid (AEMO 2013b). Finally, the topography in these regions in South Australia and Victoria features elevated sites located close to the coast that could be useful for seawater PHES.

Figure 34 shows the results of MEI's terrain and cost mapping exercise for the Spencer Gulf region of South Australia. Potential PHES sites located along the coasts of the Eyre and Yorke Peninsulas that would use seawater "turkey-nest" type dams are marked by the red or white contours, which refer to RCC-type dam construction or earth-embankment-type dams respectively.

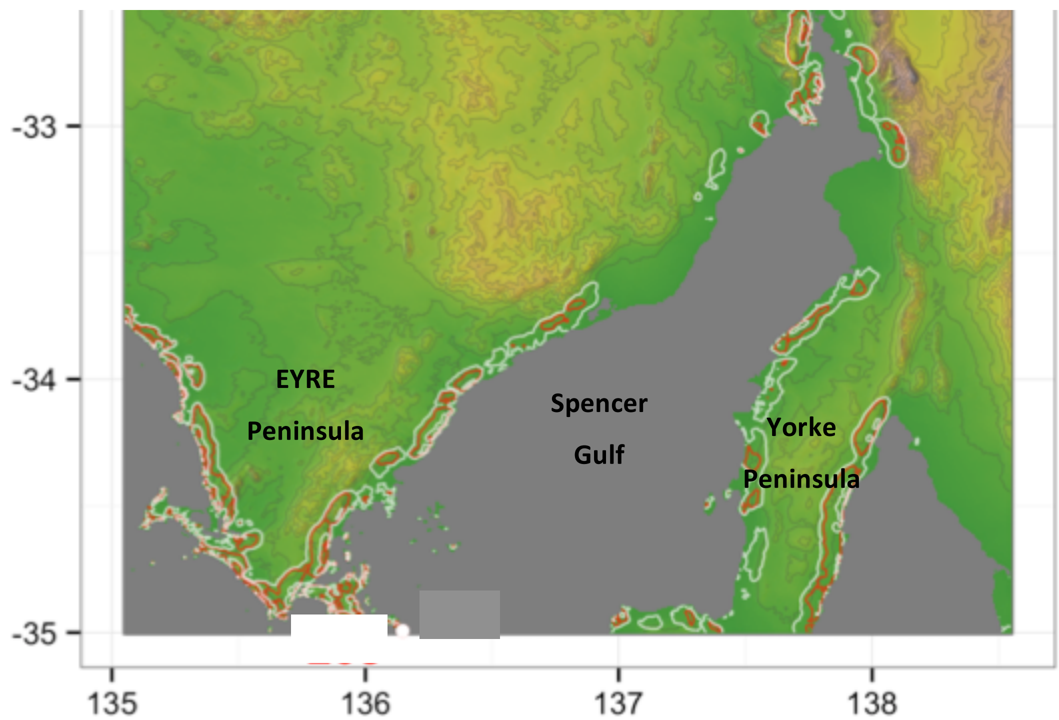


Figure 34: Terrain analysis results for Eyre and Yorke Peninsulas and Spencer Gulf region, South Australia. Contours represent cost-preferred sites based on RCC-type dam costs (red) or earth-embankment-type dam costs (white). Piping / tunnelling cost input as A$ 100 million/km. Storage capacity input as 5,000 MWh. (MEI)

Figure 35 shows a more-detailed example of terrain and cost analysis output for a region on the southern Eyre Peninsula. These results pertain to seawater PHES schemes.

Note that on these charts the spectrum of terrain colours used (brown-yellow-green) do not represent elevation but rather represent costing model results. The brown-to-whitish colours depict the most cost-effective sites. These are generally located at higher elevations nearer to the coast. Yellow-to-green areas depict less cost-effective sites.

Red or white contour lines indicate lines of constant cost for RCC-type and earth-embankment-type dams respectively. PHES would be cheaper to develop within these contour lines than it would be outside of those contours.

The left-hand-side chart in Figure 35 (labelled “concrete”) shows optimum locations for roller-compacted concrete (RCC) type dams, while the right-hand-side chart (labelled “earth”) shows optimum locations for earth-embankment-type dams. Given that RCC-type dams are more expensive than earth-embankment-type dams, they tend to be more cost-effectively placed at higher elevations that are the earth-embankment-type dams, even if this means they are located further from the coast.

The single lowest-cost location is shown with dots coloured either red (for RCC-type dams) or white (for earth-embankment-type dams).

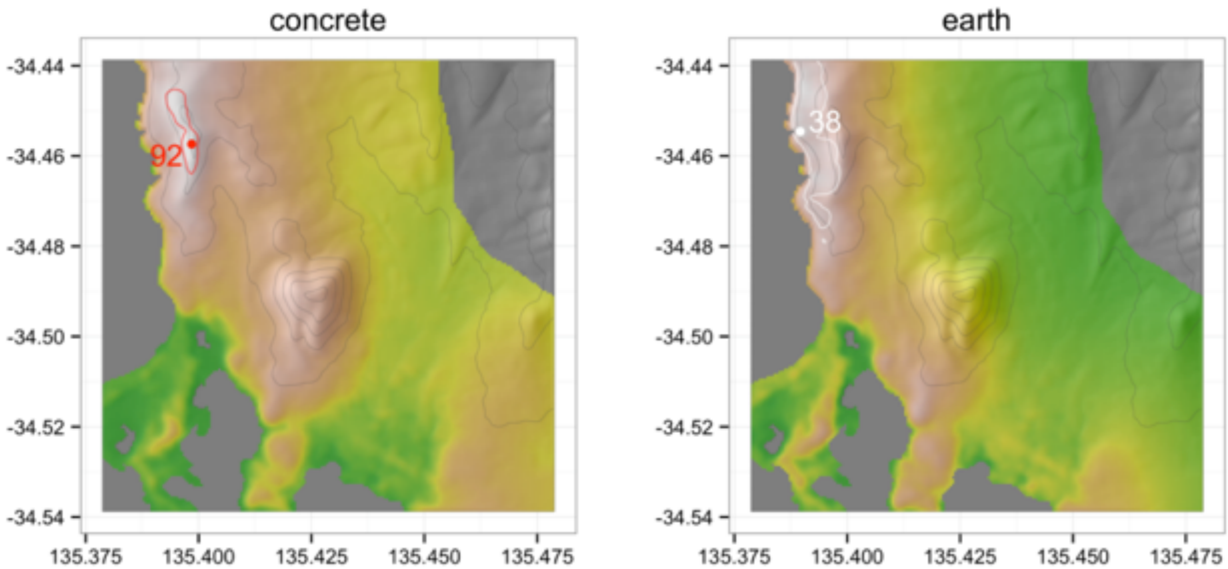


Figure 35: Example terrain analysis output over region on the Eyre Peninsula. Colour scale represents relative cost of PHES at each pixel. Piping / tunnelling cost input as A$ 50 million/km. Storage capacity input as 1,000 MWh. (MEI)

Figure 36 shows cost results for individual 30 x 30 metre land-area pixels, plotted as values dependent on elevation (x-axis) and in coloured bands that represent the distance from the coast. For the results shown in Figure 36, piping / tunnelling cost was assumed to be A$ 50 million/km.

The plotted values are useful for understanding the spread of potential sites - whether there are many sites within a similar cost range, or whether the most optimal is limited to a very particular location.

The left-hand side chart shows that for RCC-type dams, the lowest-cost sites are located at approximately 150 metres of elevation one kilometre from the coast. Sites closer to the coast but at lower elevations are more expensive, as are sites at higher elevations but further from the coast.

The right-hand side chart shows that for earth-embankment-type dams, the lowest-cost locations are at approximately 50 metres of elevation and less than one kilometre from the coast. Sites closer to the coast but at lower elevations are more expensive, as are sites at higher elevations but further from the coast.

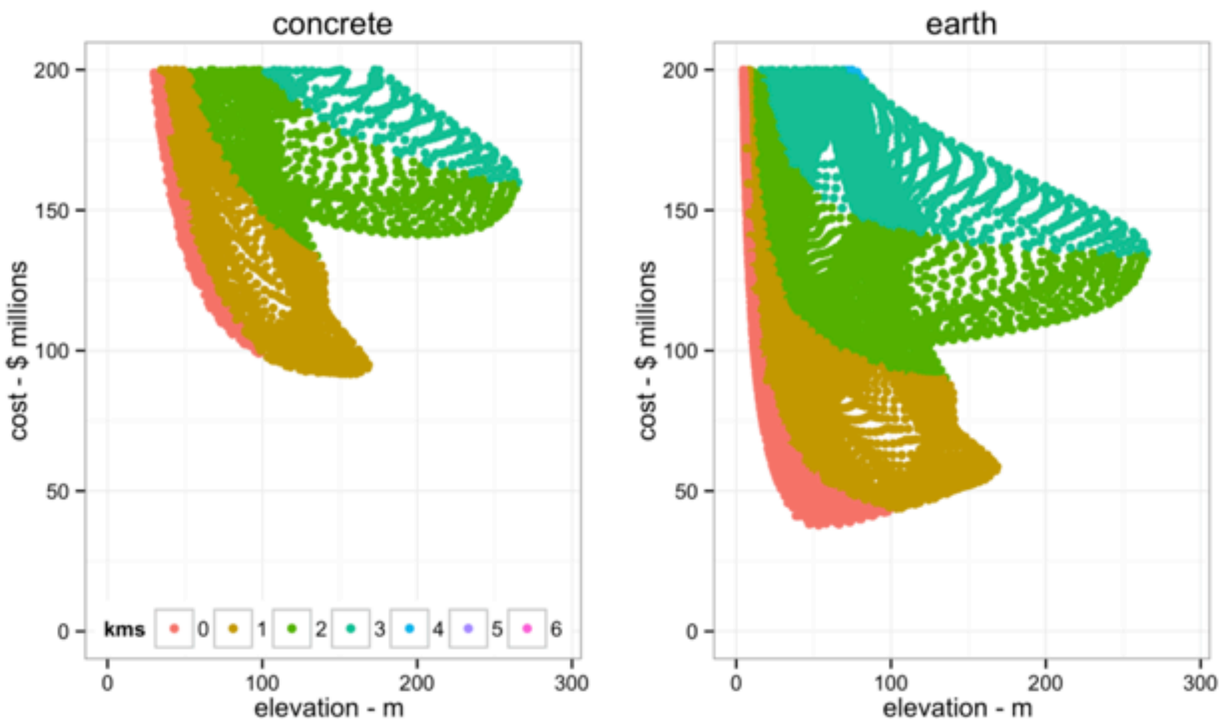


Figure 36: Cost of each pixel in the region shown in Figure 35, as function of elevation. Colour scheme denotes distance from coast. Piping cost input as A$ 50 million/km. Storage capacity input as 1,000 MWh. (MEI)

Because RCC-type dams are more expensive than earth-embankment-type dams, the costs saved by building a smaller dam at a higher elevation outweigh the extra costs required for the piping / tunnelling that would connect the two water bodies. The large hill shown in the centre of Figure 35 appears in Figure 36 as the 'bulge' of green and blue values at elevations greater than approximately 180 metres. However the lowest-cost site on that hill is still around 50% more expensive than lower sites closer to the coast in the northwest part of the analysis region.

This analysis is sensitive to the input parameters. Changing the piping / tunnelling cost from A$ 50 million/km to $100 million/km will give different results, and in particular the desired reservoir energy storage capacity is important. For larger energy storage requirements, the reservoir cost becomes much more dominant than the piping / tunnelling cost, driving the optimal sites toward higher elevations, rather than toward low-net-head sites near the coast.

MEI case study site selection

Based on the analysis described in general above, several dozen areas around South Australia and western Victoria were found to be worthy of further investigation. MEI selected seven sites for case study, as shown in Figure 37, including:

- East Eyre 2, on the Eyre peninsula of South Australia
- East Eyre 3, on the Eyre peninsula of South Australia
- El Alamein, at the head of the Spencer Gulf in South Australia
- Yorke 1 at the head of Gulf St. Vincent in South Australia
- Fleurieu 3, on the Fleurieu peninsula of South Australia
- Portland, in western Victoria.

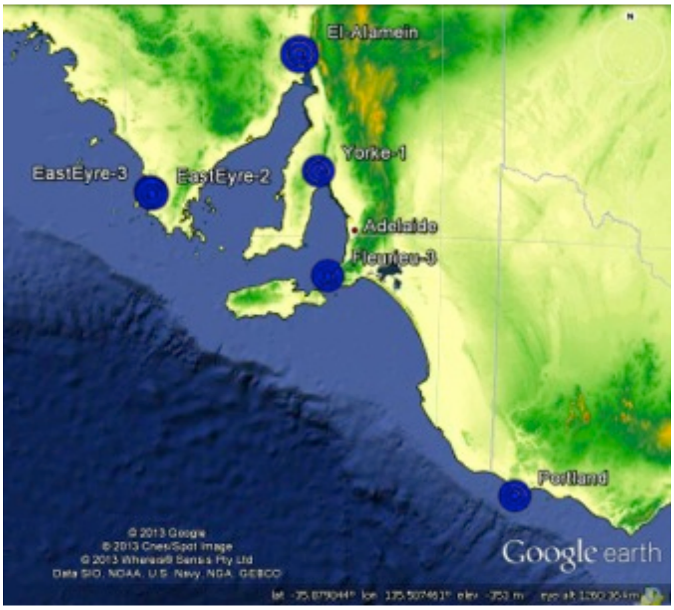


Figure 37: PHES case study example sites in South Australia and western Victoria. (Google Earth and MEI)

These case-study sites were selected based not only on the quality of the sites as locations for PHES but also so that a range of geographical and topographical characteristics could be investigated. These included such differences as wind quality and distance to the electricity transmission grid.

Due to the complex and time-consuming nature of this analysis, combined with uncertainties in the inputs, the selected sites do not necessarily represent optimal PHES locations at both the macro and micro scales. Nevertheless for the purposes of this study, a specific site location has been pinpointed in each of the areas studied, ignoring potential conflicting land-use constraints.

In the case studies that follow, input parameters such as piping / tunnelling costs and energy storage capacity were varied to test PHES project economics.

East Eyre 2 sites

There are a number of potential sites along the east coast of the southern Eyre Peninsula at elevations of 100 to 200 metres above sea level that are within a few kilometres of the coast. East Eyre 2 is an area with several promising sites.

For the East Eyre 2 area, the optimal sites found by the selection model were quite different depending on whether the dam is RCC-type or earth-embankment-type, and also on other chosen modelling inputs.

Assuming a low piping / tunnelling cost of A$ 10 million/km and energy storage capacity of 200 MWh, the optimal RCC-type dam site is near the top of the hill in the centre of the region at an elevation of 114 metres (Figure ZZ – left panel).

The optimal earth-embankment-type dam site (Figure 38 – right hand-side chart) is located lower down the hill at an elevation of 53 metres and closer to the coast. In order to store the same amount of energy, the selected lower-elevation site would require roughly twice the amount of water storage capacity than would be required at the higher site. Nevertheless this site is optimal given the lower costs of constructing earth-embankment-type dams, when compared with RCC-type dams.

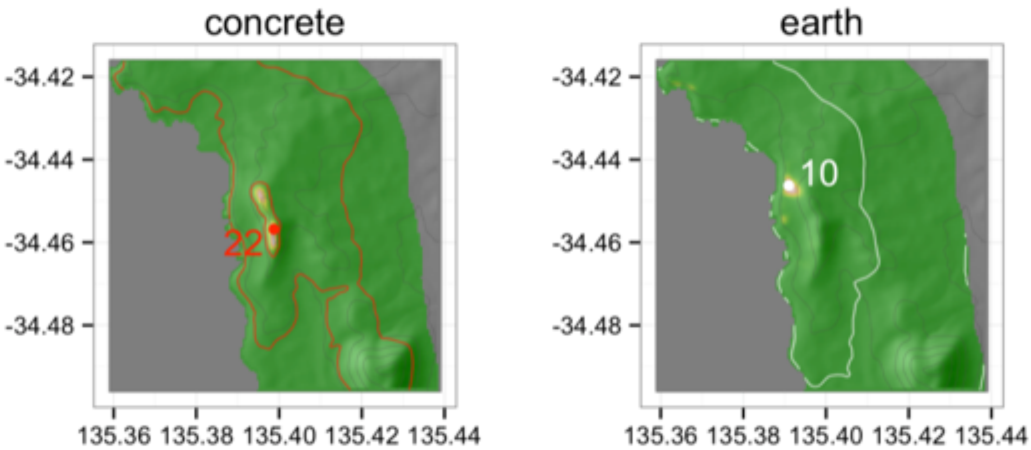


Figure 38: Terrain analysis for East Eyre 2 area.
Piping / tunnelling cost input as A$ 10 million/km and storage capacity input as 200 MWh.
Terrain colour scheme (green/brown) represents relative reservoir cost for each pixel, not topography. (MEI)

East Eyre 3 sites

The East Eyre 3 area is slightly north of the area denoted as East Eyre 2. As shown in Figure 39, the terrain analysis for East Eyre 3 identifies the East Eyre 2 hill as *the* most optimal site in this area. However the 121 metre-elevation hilltop identified in the centre of the East Eyre 3 area is also identified in this modelling as having strong PHES potential.

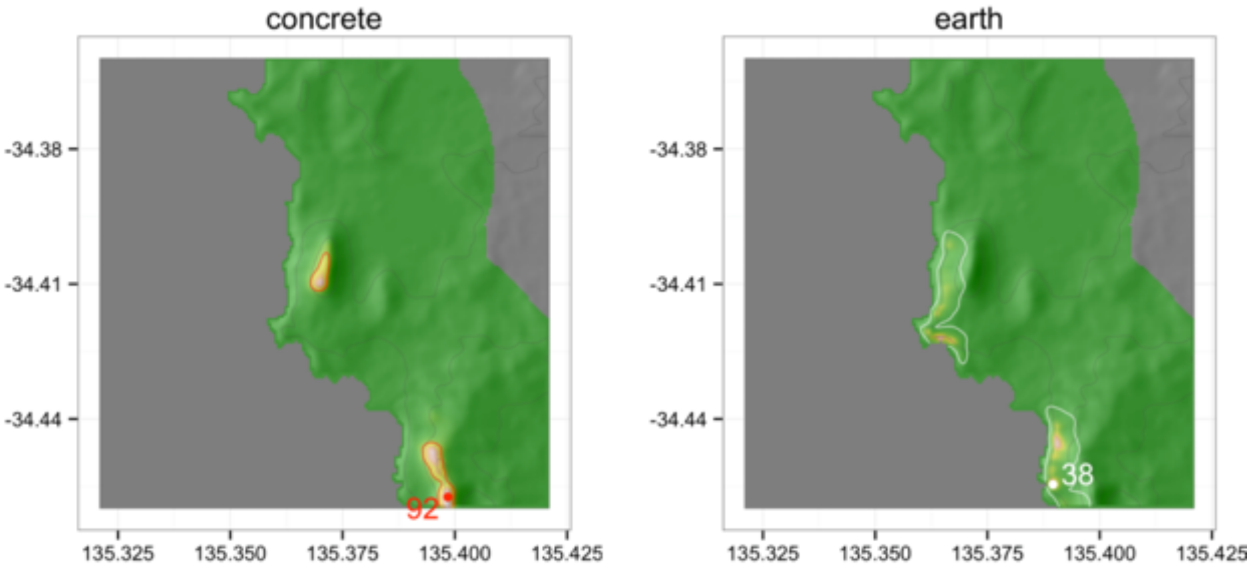


Figure 39: Terrain analysis results for the East Eyre 3 area.
Piping / tunnelling cost input as A$ 50 million/km. Storage capacity input as 1,000 MWh.
Terrain colour scheme (green/brown) represents relative cost for each pixel, not topography. (MEI)

Figure 40 shows results for all pixels in the East Eyre 3 area for RCC and earth-embankment-type dams.

For RCC-type dams (Figure 40 left hand-side chart), the lowest cost sites (denoted by the lower right-hand tip of the coloured area) are located approximately one kilometre from the coast at elevations of approximately 150 metres.

For earth-embankment-type dams (Figure 40 right hand-side chart), the lowest cost sites are located less than one kilometre from the coast at elevations of only 50 metres.

Because RCC-type dams are more expensive than earth-embankment-type dams, RCC-type dams are optimally placed at higher elevations, even if that means they are further from the coast.

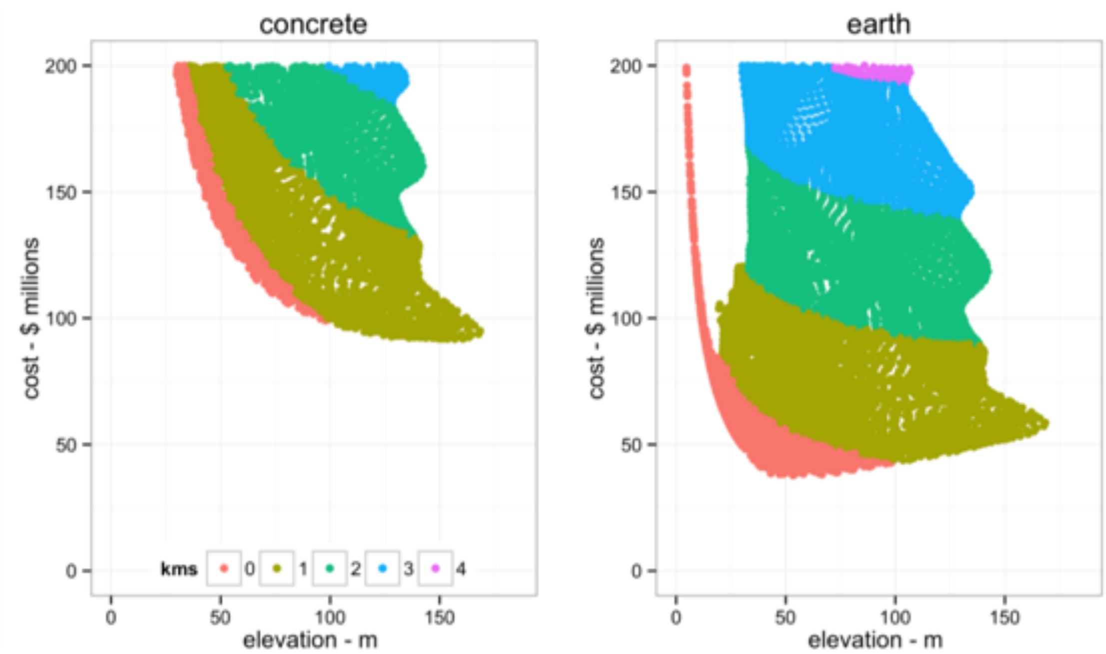


Figure 40: PHES facility cost for each pixel shown in Figure 39 as a function of elevation. Colour scheme denotes the distance to each site from the coast. Piping / tunnelling cost input as A$ 50 million/km. Storage capacity input as 1,000 MWh. (MEI)

El Alamein sites – northern Spencer Gulf region of South Australia

The northern Spencer Gulf region has a range of areas with potential seawater PHES sites. These are indicated by the red or white contour lines in Figure 45.

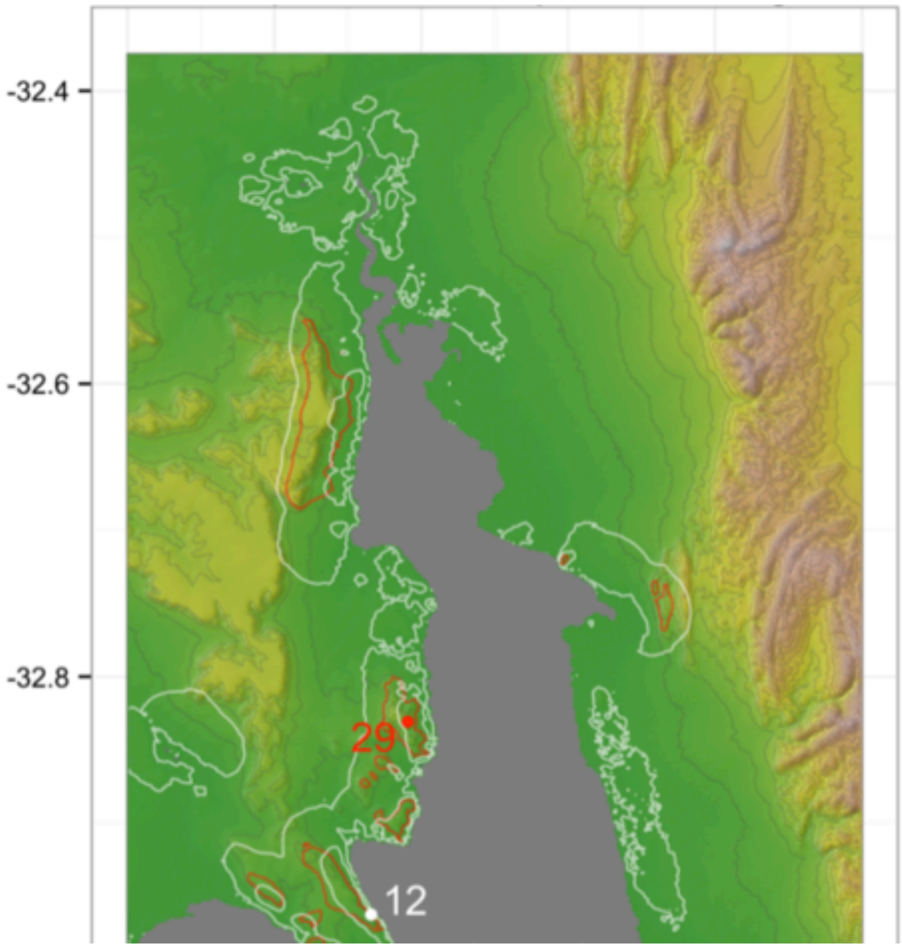


Figure 45: PHES terrain analysis for northern Spencer Gulf area. Colour scheme represents actual topography. Red contours denote RCC-type dams. White contours denote earth-embankment-type dams. Piping / tunnelling cost input as A$ 10 million/km. Storage capacity input as 200 MWh. (MEI)

Although MEI identified other potentially interesting PHES sites further south, MEI selected the area around the El Alamein army camp just south of Port Augusta because of its sharp relief and proximity to transmission connections at Port Augusta. The quality of the seawater that could be readily accessed at this site was not considered.

Figure 46 shows a close up of the selected El Alamein area. A storage capacity of 200 MWh has been input which results in optimal sites being located below the high escarpment.

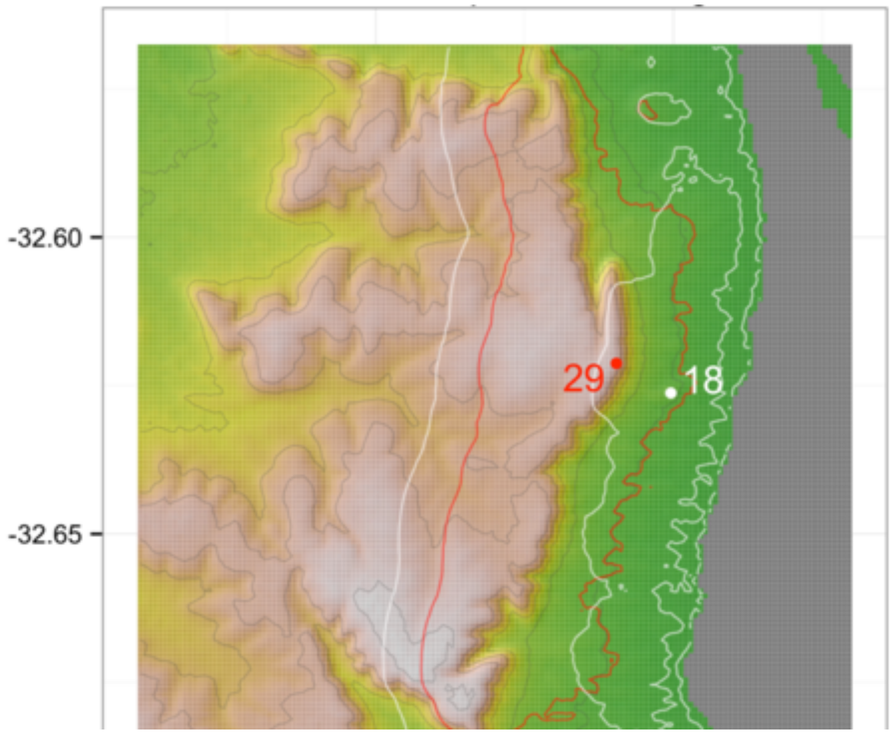


Figure 46: PHES terrain analysis for El Alamein site. Colour scheme represents topography. Red contours denote RCC-type dam. White contours denote earth-embankment dam. Piping / tunnelling cost input as A$ 10 million/km. Storage capacity input as 200 MWh. (MEI)

For the El Alamein site, Figure 47 shows the profile from reservoir site to the coast that the pipeline would need to traverse. As an example exercise, it has been designed to tunnel off the steep escarpment before running to the coast above-ground. It may be possible that the gradients would be compatible with running surface piping the entire length.

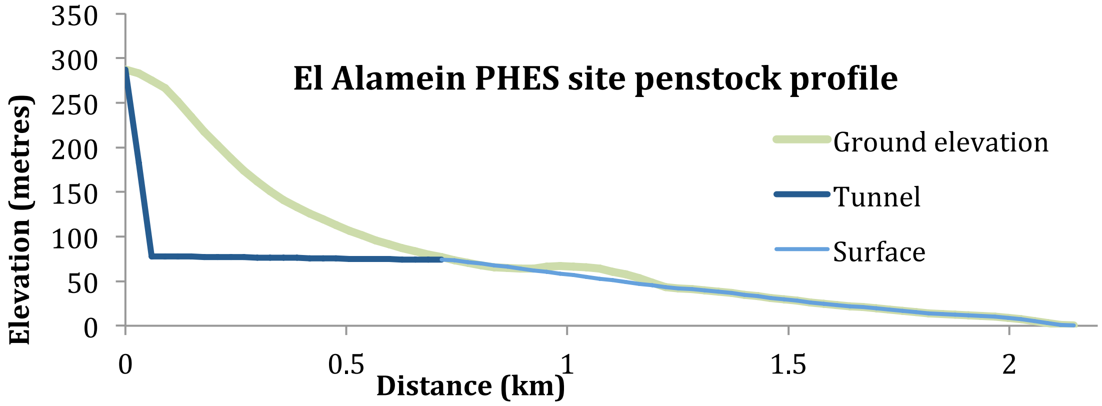


Figure 47: Piping/tunnelling layout at El Alamein site. (MEI)

Yorke 1 sites

The area around the head of Gulf St Vincent has interesting topography for this analysis with elevations exceeding 150 metres aligned roughly north-south trending away from the Gulf. This area is suited for studying the cost trade-off elevation and distance from the ocean. The red and white contours shown in Figure 48 indicate potential PHES sites.

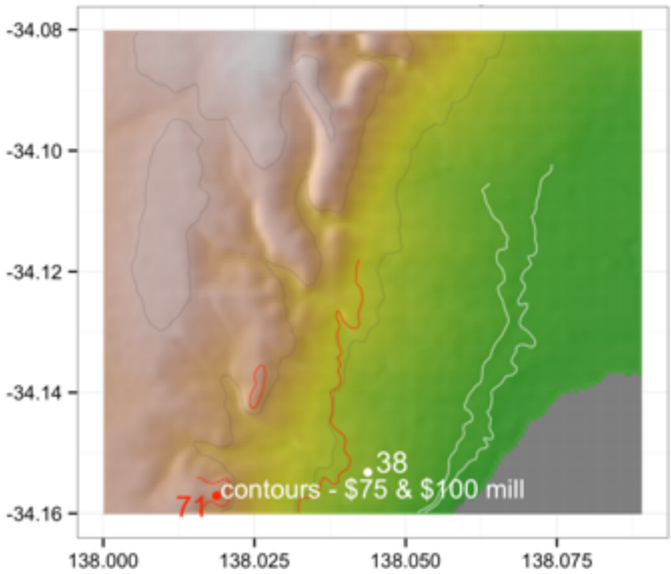


Figure 48: Terrain analysis results for Yorke-1 area. Colour scheme represents topography. Piping / tunnelling cost input as A$ 10 million/km. Storage capacity input as 500 MWh. (MEI)

Site selection varies significantly depending on the model input parameters of cost and storage requirements. As shown in Figure 49, The Yorke 1 site was selected has an elevation of 88 metres. This site is at a midway point between the coast and sites with higher elevation further inland.

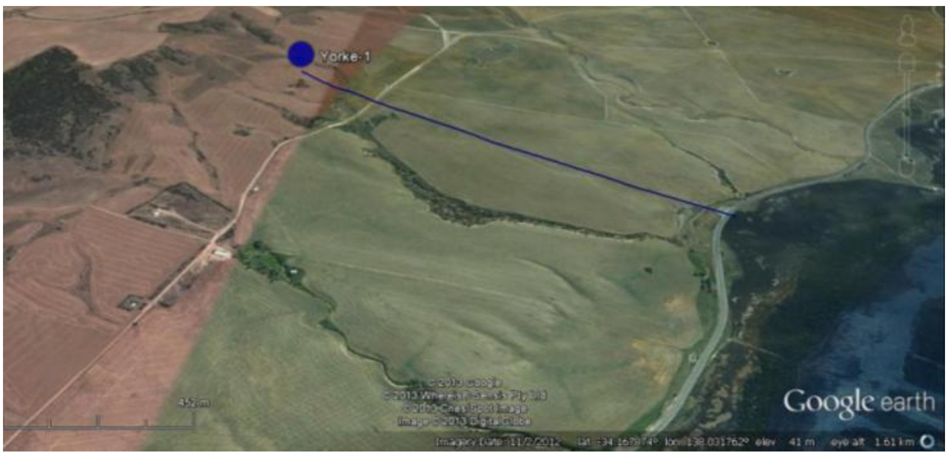


Figure 40: Yorke 1 site location, with pipeline pathway shown as blue line. (Google Earth, 2013)

Fleurieu Peninsula sites

The Fleurieu Peninsula, with land elevations of 100 to 200 metres rising from the coast, was found to have strong seawater PHES potential over a wide range of modelling input parameters. The red and white contours in Figure 50 show potential PHES locations.

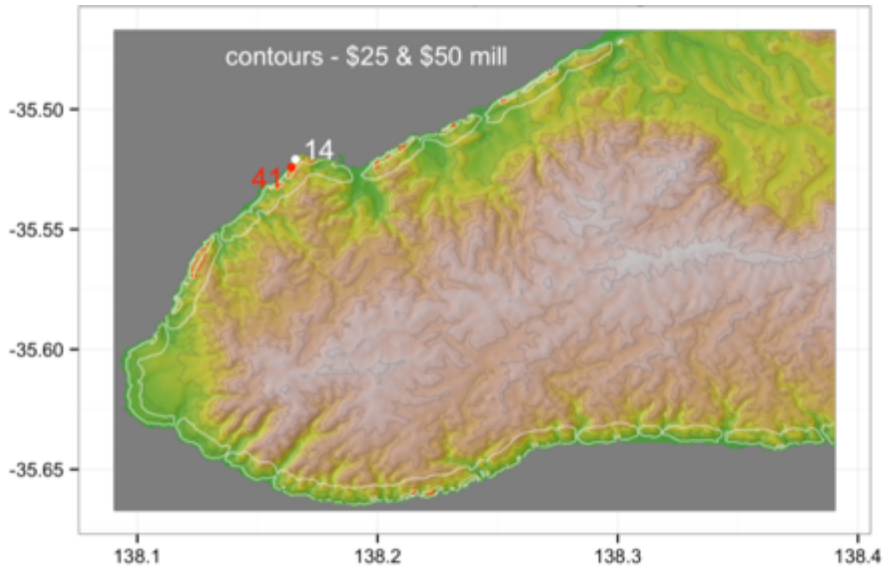


Figure 50: Terrain analysis for Fleurieu peninsula. Piping / tunnelling cost input as A$ 50 million/km. Storage capacity input as 500 MWh. Colour scheme represents topography. (MEI)

The Fleurieu peninsula area shown in Figure 51 is a good example of the height-distance trade-off. MEI's modelling selected a PHES site in this region at an elevation of 171 metres. Inland from this site, the land elevation rises to over 250 metres.

Figure 51: Potential PHES site on Fleurieu peninsula. (Google Earth, 2013)

However as shown in the cost results shown in Figure 52, MEI's site-specific PHES cost modelling found that total cost for optimal sites rises sharply for elevations greater than 150 metres.
This means that the benefits of moving to higher ground do not justify the greater piping / tunnelling costs.

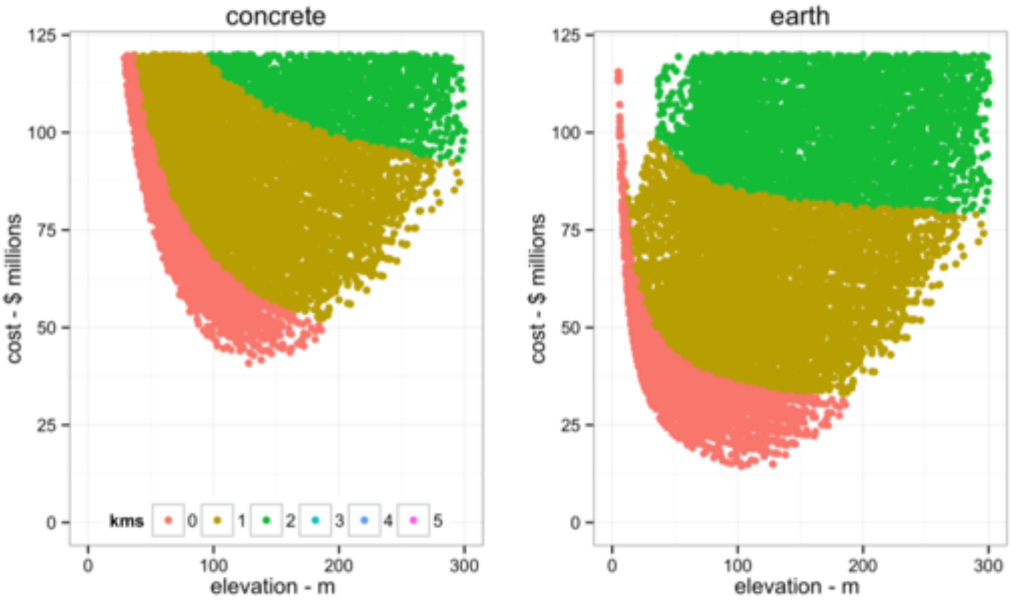


Figure 52: PHES facility cost for each pixel shown in Figure 50 as a function of elevation. Colour scheme denotes distance from coast. Piping / tunnelling cost input as A$ 50 million/km. Storage capacity input as 500 MWh. (MEI)

Due to the steep cliff at the coastline for the Fleurieu site, tunnelling is likely required. A schematic of such a tunnel is shown in Figure 53.

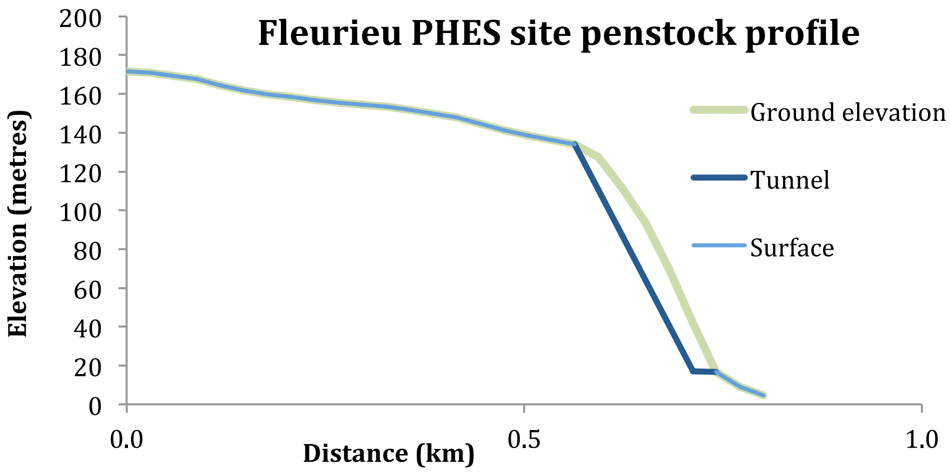


Figure 53: Possible piping / tunnelling layout at Fleurieu peninsula site. (MEI)

Portland Victoria sites

Cape Bridgewater, near Portland in western Victoria has an excellent wind resource and is the site of an existing wind farm. Most of the cape is at an elevation of 50 to 70 metres; however, there is a hill on the southeast side at an elevation of 125 metres that might be suitable for PHES as shown in Figures 54 and 55. The very edge of the coastline is a coastal park conservation area; therefore, the impacts of any PHES facility there would need to be carefully assessed.

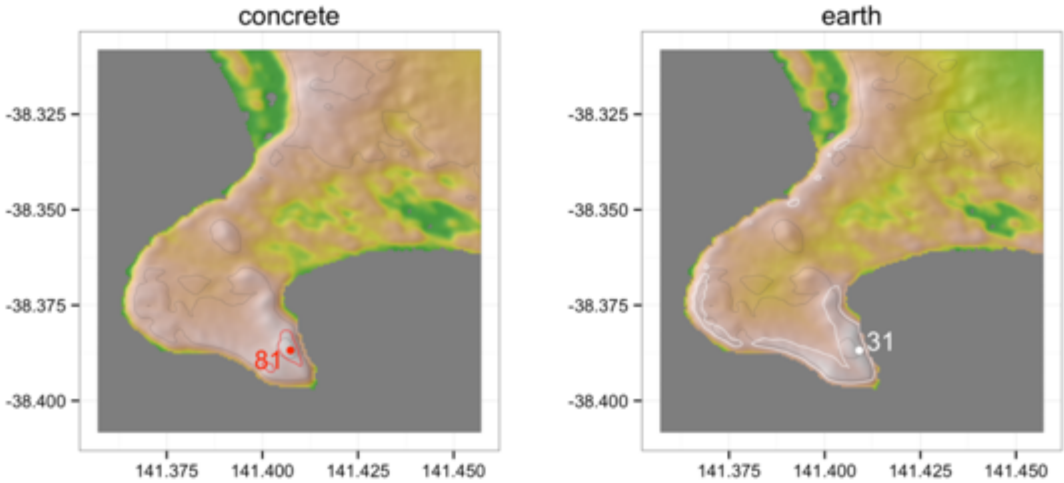


Figure 54: Terrain analysis for an area near Portland, Victoria. Colour scale refers to relative cost of PHES at each pixel. Piping / tunnelling cost input as A$ 50 million/km. Storage capacity input as 1,000 MWh. (MEI)

Figure 55: Potential Portland, Victoria PHES site at 125 metres elevation.
Existing wind farm visible in background. (Google Earth 2013)

Capital costings for the seven case study sites

This section describes the MEI-developed capital costs for the seven case-study sites described above. At all sites, facility capacity and size is set at 100 MW generation capacity, 1,000 MWh of stored energy, allowing therefore 10 hours of maximum continuous production.

The elevation and distance characteristics of the seven example are given in Table 2, along with the unit costs assumed for piping / tunnelling. (Note that East Eyre 2-A and East Eyre 2-B are two different locations.)

MEI's piping / tunnelling cost assumptions for each site differ not only to reflect the actual pipeline profiles and possible proportions of tunnelling versus surface piping, and also to subsequently test the sensitivity of economic return to these assumptions. For example, the Yorke 1 site features a relatively gentle slope between the reservoir and the coast, but the unit piping / tunnelling cost has been input at a high A$ 100 million/km in order to test the impact of that assumption on economic return for a PHES facility at that site.

Table 2: Summary of elevation, distance from the coast, and assumed piping / tunnelling cost for each site.

Site	Distance to coast (km)	Elevation (m)	Assumed piping/tunnelling cost (A$ million/km)
East Eyre 2-A	0.2	53	10
East Eyre 2-B	0.6	114	10
East Eyre 3	0.6	121	10
El Alamein	2.1	287	50
Fleurieu 3	0.8	171	100
Portland	0.4	125	50
Yorke 1	2.1	88	100

Figure 56 shows the capital cost of a 1,000 MWh / 100 MW PHES system for each of the case study sites.

Taken together, the costs for the reservoir, piping / tunnelling, and electrical and mechanical (E&M) facilities are considered “direct costs”. Engineering, procurement and construction management (EPC, 10%), contingency (20%), and owner’s costs (20%) are applied as fixed percentages of direct costs.

As a result of the different geographical parameters for each site and also because of the different costing assumptions, these sites exhibit capital costs that range from approximately A$ 200,000/MWh to over A$ 500,000/MWh of stored energy (A$ 2,000/kW to 5,000 /kW of installed generation capacity).

The East Eyre 2-A site has the highest reservoir cost because that site has the lowest elevation, which means that a larger reservoir is required to store 1,000 MWh of energy. El Alamein has the lowest reservoir cost because that site has the highest elevation.

Yorke 1 has the highest piping / tunnelling costs because it is located 2.1 km from the coast and has been arbitrarily assigned a high unit piping / tunnelling cost of A$ 100 million/km, whereas East Eyre 2-A was assigned lower piping / tunnelling costs.

The capital costs for sites other than Yorke 1 range from approximately A$ 200 million to A$ 300 million for a facility with storage capacity of 1,000 MWh (A$ 200,000/MWh to A$ 300,000/MWh). These cost metrics can be compared with the range of literature costs presented in Figure 21.

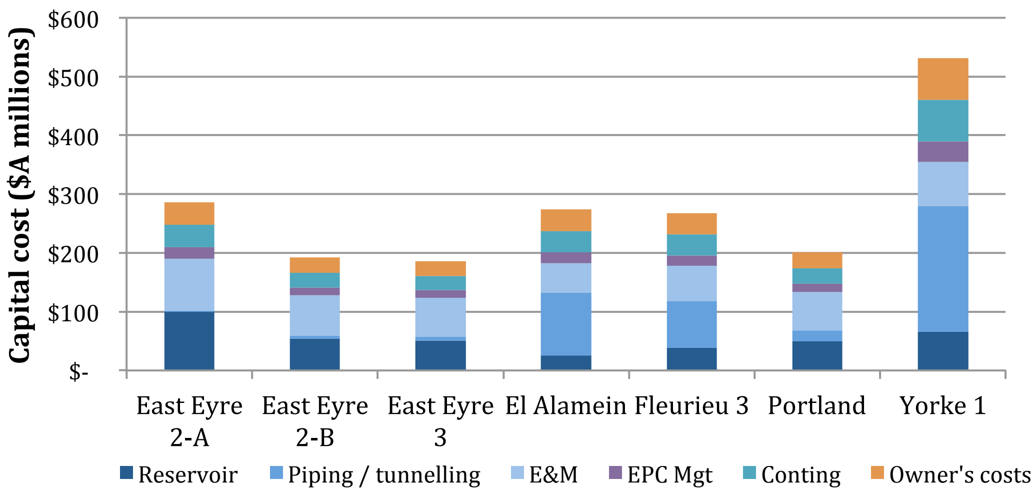


Figure 56: Example PHES system costs. 100 MW generation capacity, 1,000 MWh energy storage capacity, 10 hours of stored energy at maximum output. (MEI)

10. MEI levelised cost of electricity (LCOE) analysis

Levelised cost of electricity (LCOE) is a standard metric used for comparing the cost of electricity from different generation sources. A full discounted cashflow analysis (at an assumed discount rate) is applied to the capital and operating costs and then the required income per unit of electricity sold is calculated that achieve zero net present value (zero NPV, i.e. break even), given the projected annual electricity output.

Figure 57 shows MEI's levelised cost of energy (LCOE) results for PHES facilities plotted as a function of the average annual capacity factor. Annual capacity factor is the annual energy sent out divided by the theoretical maximum output of the facility possible if it operated at full capacity at all times. In reality, a PHES facility can never exceed 50% capacity factor because of the time needed to pump water to the upper reservoir. Indeed, due to round-trip efficiency losses, annual capacity factor will always be lower than 50% even if the facility is assumed to be operating in either pumping or electricity-generating mode at all times.

The LCOE values plotted in Figure 57 represent the average price that needs to be earned (per unit of electricity sold) over and above the price paid for electricity purchased to pump water to the upper reservoir. It also approximates the average arbitrage value that a PHES facility would need to achieve in order to break even economically.

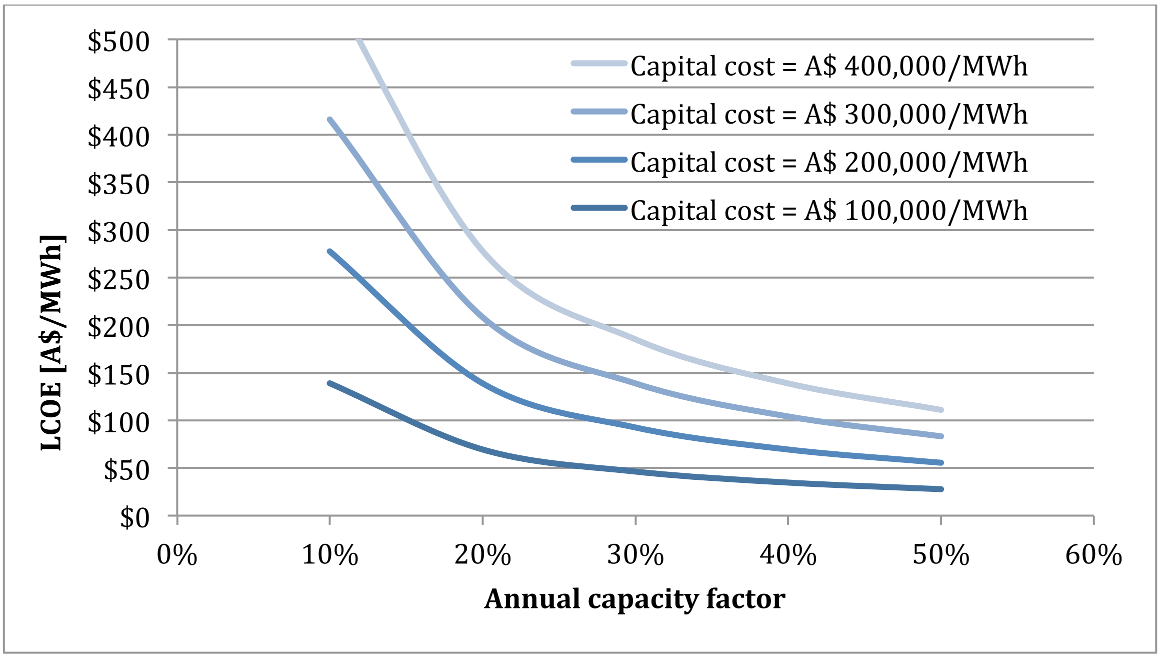


Figure 57: LCOE: Required sales price for a unit of PHES-derived electricity. Zero electricity purchase cost assumed. Analysis period = 30 years. Construction period = 2 years. Real discount rate input as 8%. Tax rate = 30%. Annual operating costs input as 1% of capital costs.

Four lines are plotted on Figure 57, corresponding to capital costs ranging from A$ 100,000/MWh of energy stored to A$ 400,000/MWh of energy stored.

The LCOE values shown range from less than A$ 50/MWh to A$ 500/MWh. This compares to the LCOE values given for PHES in Figure 8 of approximately A$ 200/MWh to A$ 300/MWh.

The LCOE values given in Figure 57 are not necessarily useful for direct comparison against LCOE's calculated for electricity generation technologies (e.g. nuclear, fossil or renewable generators) because energy storage facilities can operate quite differently from some electricity generation facilities.[2] For example, PHES can play a role similar to that of a gas peaking-plant, operating during only a small fraction of the time (e.g. 5 to 10% capacity factor) but on those occasions when high-electricity-demand / low-electricity-supply situations create a spike in wholesale electricity prices. The value of electricity sent-out in those periods could be much higher than the LCOE values plotted in Figure 57. Such a role for PHES is described in the next section.

11. MEI analysis of energy storage arbitrage value

This section describes MEI's analysis of the arbitrage value of energy storage deployed in the National Electricity Market (NEM) with a focus on the South Australian market region.

Volatile prices are a common feature of competitive wholesale electricity markets globally. While market structure varies considerably from country to country, electricity prices demonstrate significant short-term variation due to underlying and common characteristics of electricity supply. To date, electricity has been generally considered a non-storable commodity (Anderson and Hu, 2008). The lack of cost-competitive options to store electrical energy on a significant scale means that electricity markets rely on the real-balance of supply and demand: power consumption and production need to match each other very closely. This, combined with considerable variations in load over short periods of time, results in highly volatile prices.

This volatility provides opportunities for energy arbitrage, the ability to buy power when power prices are low, and reselling it at a higher price hours or perhaps days later. A large part of the value of energy storage comes from its ability to capture this price differential. To date, electricity grids around the globe have operated effectively with very little storage. However, cost effective methods of storing electricity can help improve the efficiency and reliability of the grid, and capitalize on the arbitrage opportunities that are presented by the volatile electricity prices.

In MEI's analysis, first, the basic relationship between storage capacity and the arbitrage value of energy storage is characterised using a 'small device' energy arbitrage approach, under an optimal operating regime and 'perfect foresight' of electricity prices. Second, the impact that electricity price

[2] Other comparative metrics used in the energy storage industry include Levelised Cost of Capacity (LCOC). (Sandia 2013)

uncertainty has on arbitrage value is evaluated to determine a 'real world' estimate of arbitrage value and an estimate of the accuracy of analysis based on 'perfect foresight'.

'Small device' energy arbitrage

'Small device' energy arbitrage analysis is a commonly used way to analyse the viability of energy storage. This technique typically investigates the maximum revenue a storage device can generate via the purchase of low-cost electricity and sale of high-cost peak electricity in an electricity market. The storage device is assumed to be sufficiently small that it doesn't affect prices, i.e. it is a 'price taker'. Future electricity prices are also assumed to be known ahead of time ('perfect foresight'), and hence perfect optimization of storage device operation is possible.

This technique has been applied to many electricity markets around the world. In the USA, Sioshansi et al. (2009) analysed the PJM interconnection, and Walawalkar et al. (2007) analysed the NYISO interconnection. Figueiredo et al. (2006) investigated and compared the economics of 14 power markets. Graves et al. (1999) looked at the arbitrage opportunities of storage in the USA, and compared these to international markets. Connolly et al. (2011) compared optimal arbitrage profits across 13 electricity spot markets. The Sioshansi and Connolly references consider different operational strategies, to evaluate 'real-world' arbitrage opportunities, while incorporating the uncertainty of future electricity prices.

This section of the report aims to complement the earlier work, evaluating the arbitrage opportunities in the NEM, and considering the implication of 'real world' electricity price forecasts. While this analysis was completed in the context of a broader pumped hydro analysis, it is device agnostic and applicable to any storage device.

Arbitrage value analysis for the National Electricity Market (NEM)

MEI analysed the historical arbitrage value for a 'small device' in the NEM. The NEM is a gross pool, energy-only market with a cap price greater than \$10,000/MWh[3], which consists of five interconnected market regions. While the regions are interconnected and operated from the same central dispatch process, each has its own wholesale spot price.

Half-hourly wholesale electricity prices were used to optimize the operation of a storage device, assuming perfect foresight of these prices, in the five market regions. The optimization maximized arbitrage profits and was conducted over two different horizons (yearly and daily). The two different time horizons allow intra-day and inter-day arbitrage opportunities to be compared.

A linear program was formulated to find the optimal dispatch and maximize the arbitrage profit for a hypothetical merchant[4] storage facility. This maximization problem was defined and constrained by

[3] The price cap changed over the period analysed. The price cap increased from \$10,000 to \$12,500 in 2010, and then to \$12,900 in 2012. For the financial year 2013-14, the price cap is \$13,100.
[4] Un-contracted power plant, entirely reliant on spot market outcomes.

the rated power (generation) capacity of the storage device (MW) and the hours of storage (hrs). Charging and discharging operation was optimized, while ensuring generator capacity and storage capacity limits were not violated.

MEI's analysis assumed that the storage device has the same input and output power capacity, and round trip efficiency of 75% for the base case. Consequently, ten hours of charging (pumping) is required for 7.5 hours of discharge (generation). The sensitivity to round trip efficiency is discussed in a later section.

Figure 58 shows the hourly South Australian energy prices and the corresponding optimal dispatch and revenue during a sample period (1 January, 2008). As expected, the optimal dispatch follows the prices, with energy stored during low prices and generated during high prices.

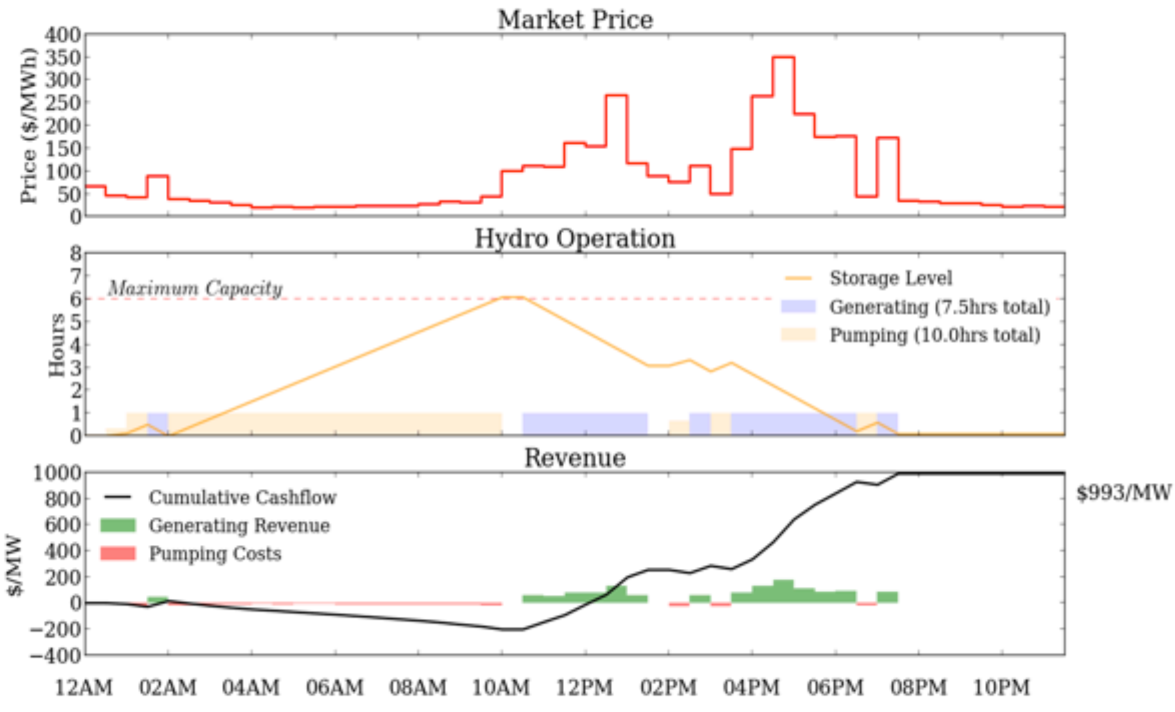


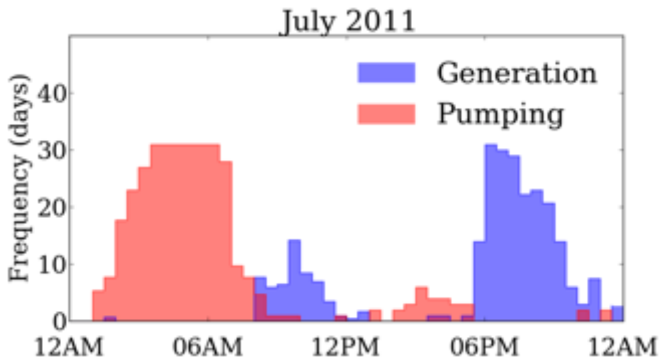
Figure 58: Optimal Dispatch - Operation and Revenue, 1 Jan 2008. (MEI)

Characteristics of the South Australian electricity market region

The South Australian market region is of particular interest for illustrating arbitrage value.

Of all NEM regions, South Australia has the largest relative variation in electricity demand and highly volatile electricity prices. Over the summer 2010-11, daily maximum demand varied between 1,500 MW and 3,400 MW (AEMO 2011). Of all NEM regions, South Australia also has the highest penetration of wind (1,203 MW) and per-household rooftop solar (470 MW, as of 1/1/2014, Clean Energy Regulator, 2014). The remaining generation capacity in South Australia is dominated by gas (2,672 MW) and brown coal (770 MW). In the most recent financial year, annual electrical energy consumption was 13,330 GWh (AEMO 2013a).

Figure 59 compares the typical optimal operating regime for a hypothetical South Australian energy storage device in summer and winter months. As expected, the dispatch follows the price and demand patterns for these particular months (bi-modal peak in winter, and evening peak in summer).



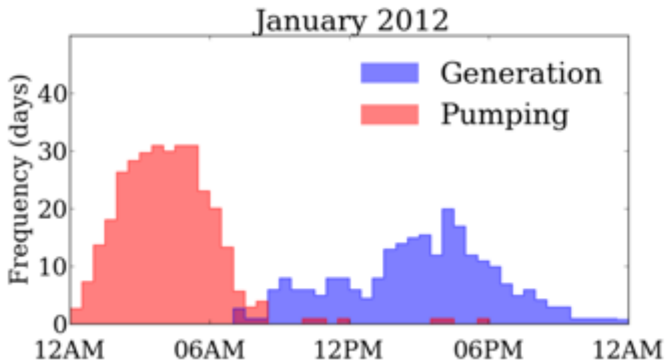


Figure 59: Optimal South Australian energy storage operating regime for winter and summer months. Y-axis shows the number of days in the month that a device is charging or discharging at different hours of the day.

Figure 60 illustrates the relationship between storage capacity and arbitrage value for South Australia.

The chart shows the 'normalized' value of storage: the value of storage as a percentage of the maximum value possible for the financial years 2006-07 through 2012-13[5]. Almost 90% of the total potential value is recovered with only four hours of storage. Beyond six hours of storage, there is limited marginal value in extending the amount of storage; the additional storage provides limited incremental arbitrage opportunities.

This relationship is displayed in the other NEM market regions (as described in following report sections), and is consistent with Sioshansi et al. (2009), which demonstrated that 50% of the value in the PJM market was recovered with the first four hours of storage, and eight hours of storage captured 85% of total potential storage.

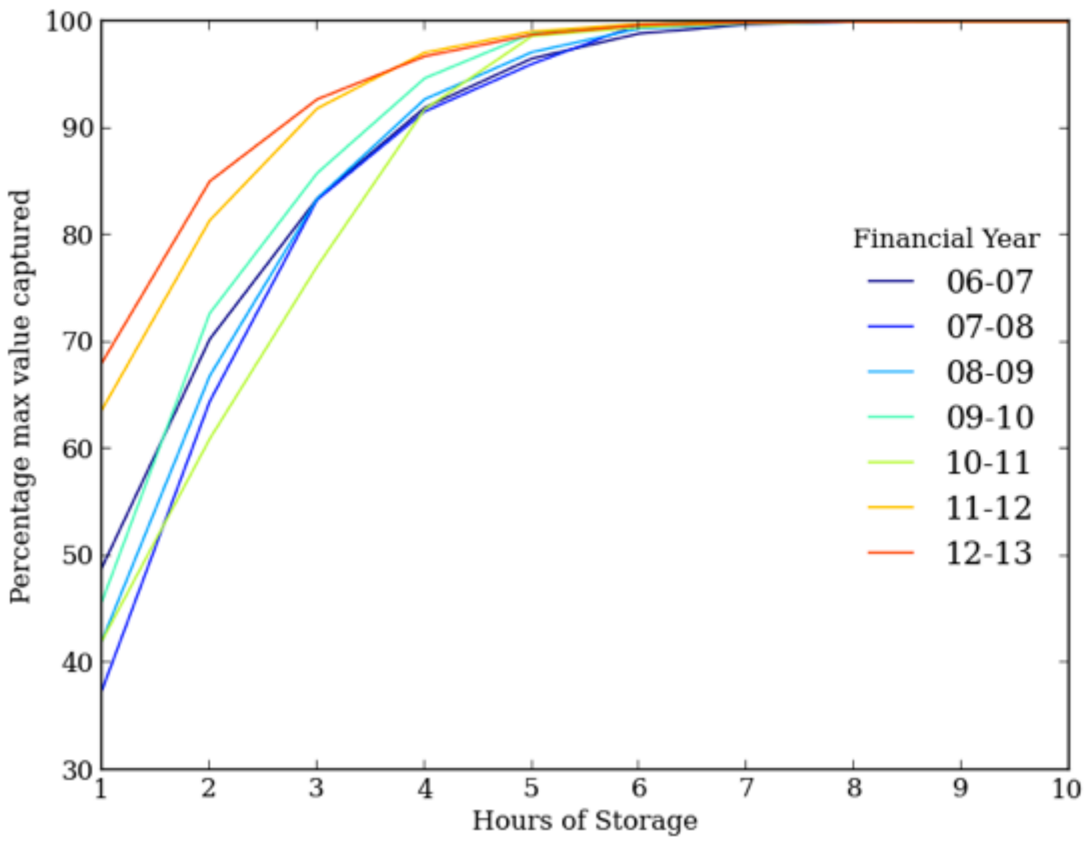


Figure 60: The arbitrage value of storage in South Australia expressed as a percentage of the maximum possible value, as a function of the number of hours of storage assumed. (MEI)

[5] The Australian financial year begins 1 July and ends 30 June.

MEI's analysis illustrates that the marginal value of additional storage capacity may be small with there being little incremental potential arbitrage value in extending storage capacity beyond six hours. However, this does not take into account the cost structure of storage technologies, and the incremental cost of extending capacity may be minor in some cases. Further, the uncertainty of short-term future electricity prices means that there may be additional value in storage beyond six hours through additional flexibility.

Figure 61 further illustrates some key characteristics of the revenue gained with energy storage. As mentioned, the NEM has a high market cap price (relative the average price and marginal cost). As such, the profit generated by a hypothetical merchant storage facility is highly skewed to a few hours of the year. Figure 61 shows that across the financial years analysed for South Australia, practically all of the arbitrage profit is generated on a small number of days (where the price rises to the market price cap).

This illustrates that achieving maximum value greatly depends on electricity being dispatched in these high-value periods. This may or may not be the case in reality, depending on location-based factors such as network constraints. The device may also not be sufficiently charged to fully exploit the high price due to uncertainty of electricity prices and the inability to accurately predict peak prices.

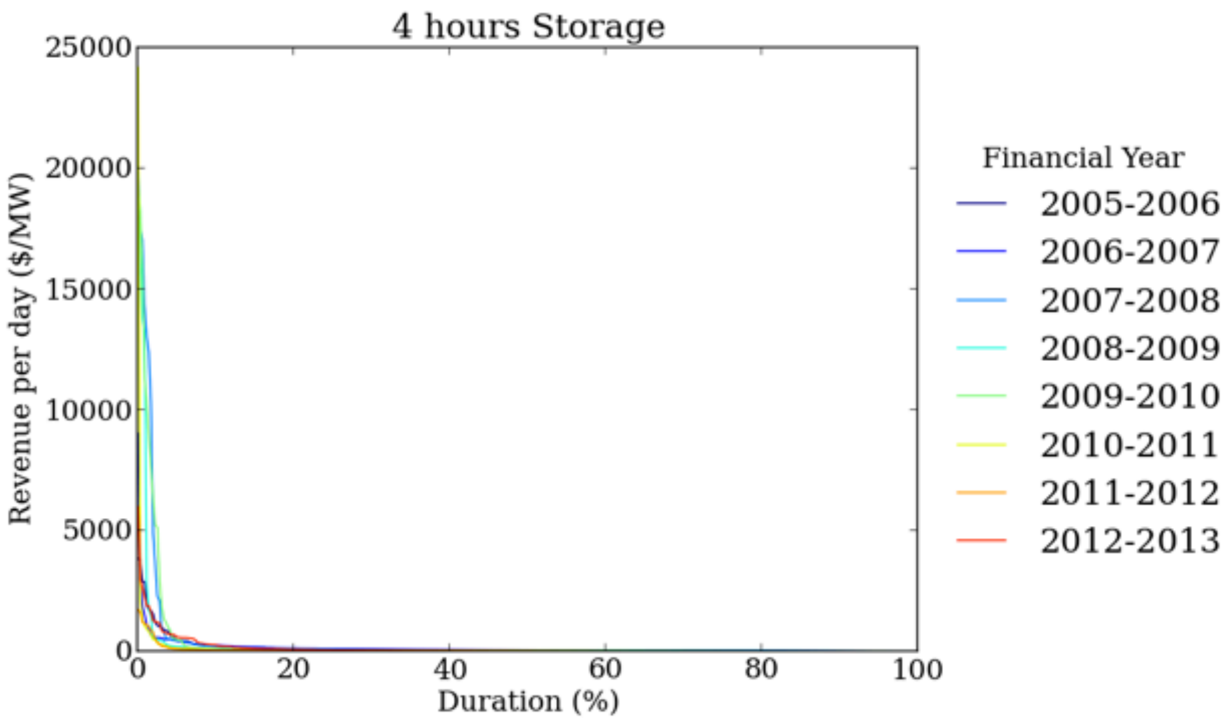


Figure 61: Energy storage device revenue duration curve for South Australia. (MEI)

PHES arbitrage value index for South Australia

Figure 62 shows the value of an energy storage device ($/kW-year) for different storage capacities (hours) over the last nine financial years, for South Australia. The value-of-storage figure represents the revenue that could be expected per year, per kW of generation capacity installed, for a fully-merchant operator under optimal operation.

This MEI modelling result can be referred to as the "PHES arbitrage value index". The highest result (over A$ 300/kW-year) was recorded in financial year 2007-08. The index fell to less than ~ A$ 50/kW-year in financial year 2011-12.

These results show that there can be considerable variation (by nearly a factor of 10) in the revenue gained over the different financial years. A possible explanation for this behaviour follows.

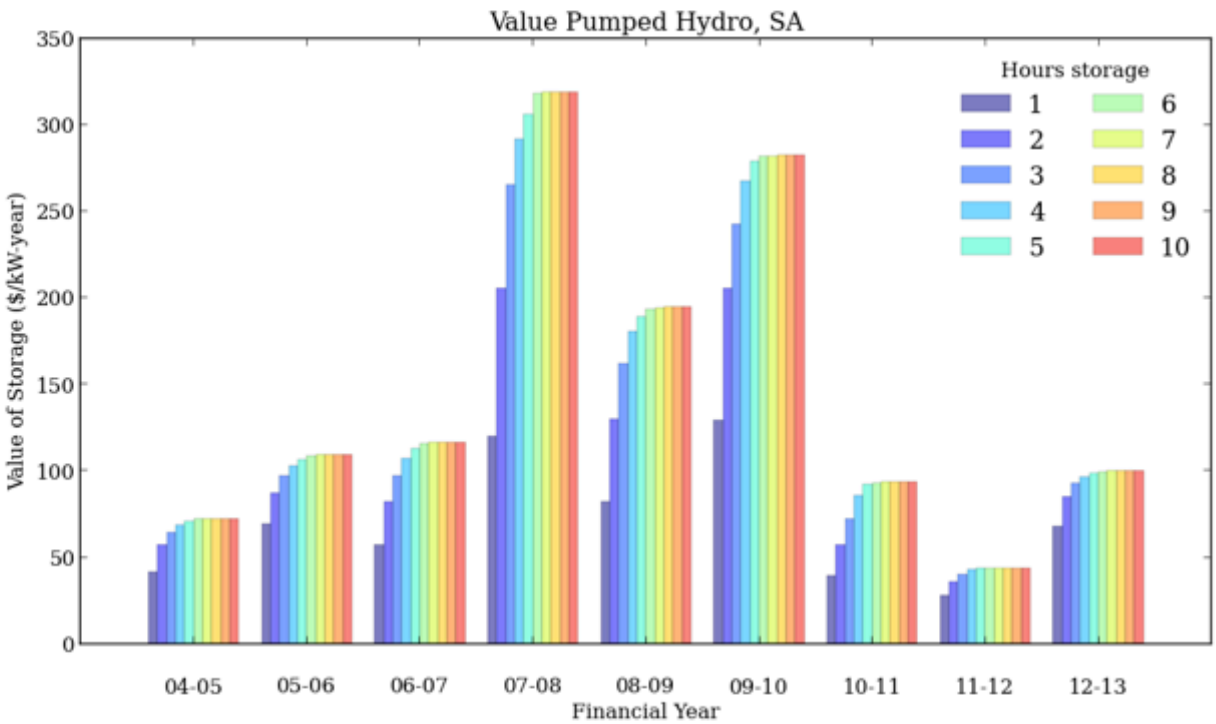


Figure 62: PHES arbitrage value index by financial year and storage capacity, for South Australia. (MEI)

The Australian Energy Market Operator (AEMO) has demonstrated the correlation between temperature and electricity demand and prices in South Australia (AEMO 2011). As shown in Figure 63, the volume-weighted electricity prices follow a very similar pattern to the number of days in South Australia reaching 38°C or higher.

On comparing Figures 62 and 63, it appears that the pattern of annual variation of the "PHES arbitrage value index" is similar to this record of high temperatures. While this is only a correlation, it is consistent with the observation that the majority of the merchant arbitrage revenue is generated on only a few days of the year (and consistent with the relationship between temperature, demand and price).

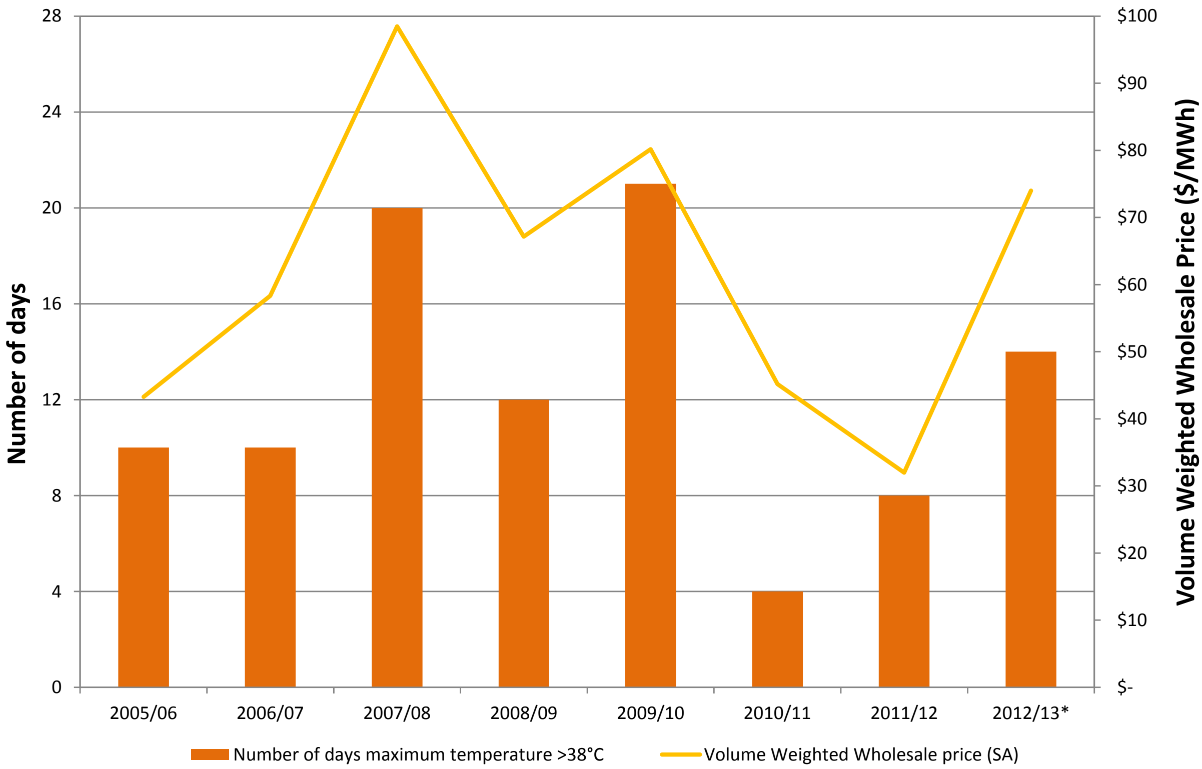


Figure 63: Number of hot days and wholesale price in South Australia [data: BOM (2014) and AEMO] (*Carbon price effective during 2012/13)

The "PHES arbitrage value index" for South Australia will be interesting to track in future as summer heat wave conditions return. However, ongoing changes in the South Australian electricity market (e.g. rooftop solar panel expansion) may mean that high index values such as seen in financial year 2007-08 do not immediately return.

PHES arbitrage value index for Victoria, Tasmania, New South Wales, and Queensland

Figures 64 through 67 show the “PHES arbitrage value index”, for the other four NEM market regions (Victoria, Tasmania, New South Wales, and Queensland), plotted on the same scale as the results for South Australia given in Figure 62.

None of these four regions recorded a higher value figure than described for South Australia (see the previous section). The index has declined in recent years in Victoria and New South Wales.

One high figure was recorded in Tasmania in financial year 2008-09. This was likely due to the drought conditions that prevailed in this hydroelectric-dependent state.

Future Queensland results will be of interest, as the index value may be rising in that state following a very low result in financial year 2011-12.

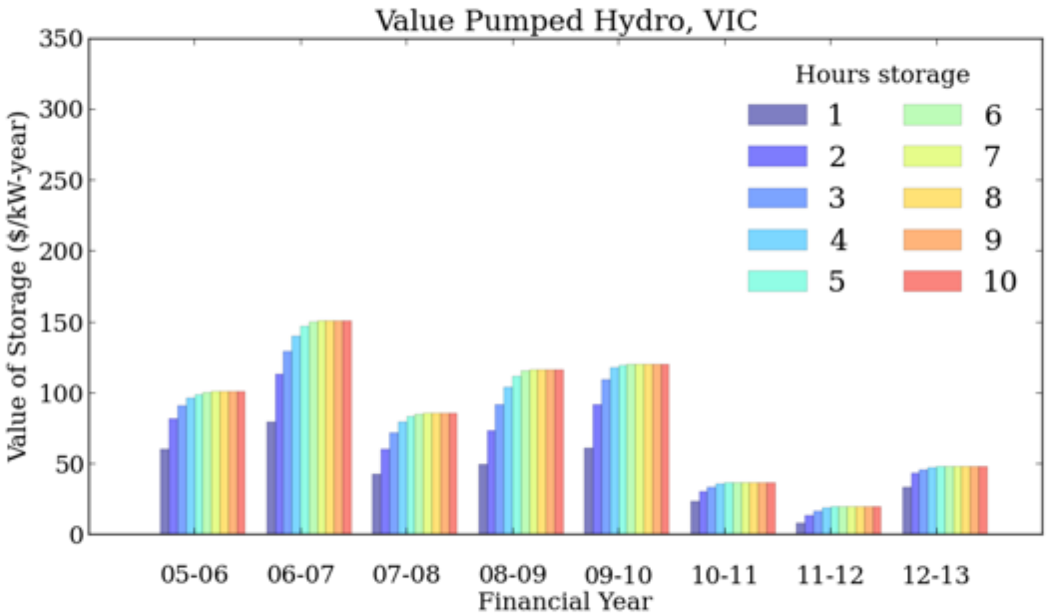


Figure 64: PHES arbitrage value index by financial year and storage capacity for Victoria. (MEI)

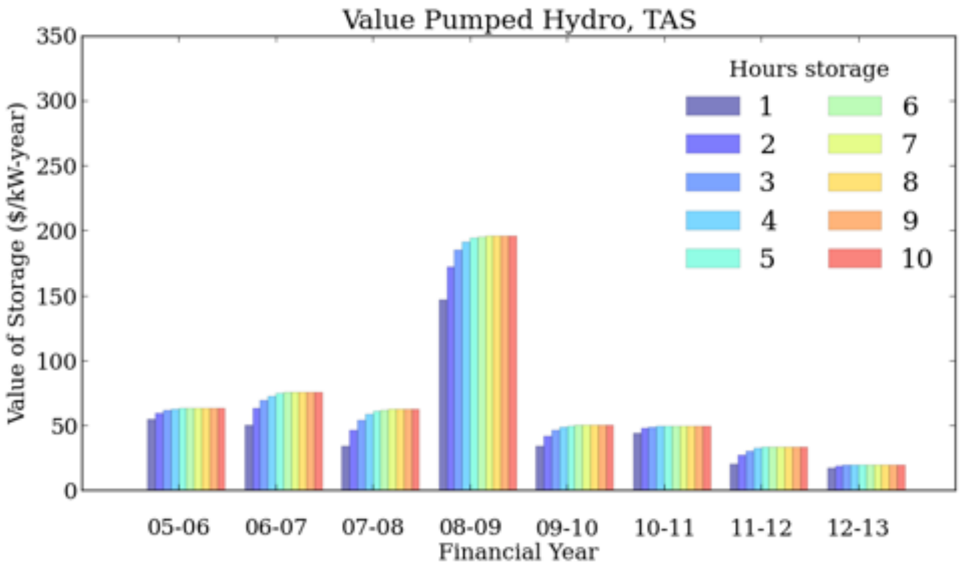


Figure 65: PHES arbitrage value index by financial year and storage capacity for Tasmania. (MEI)

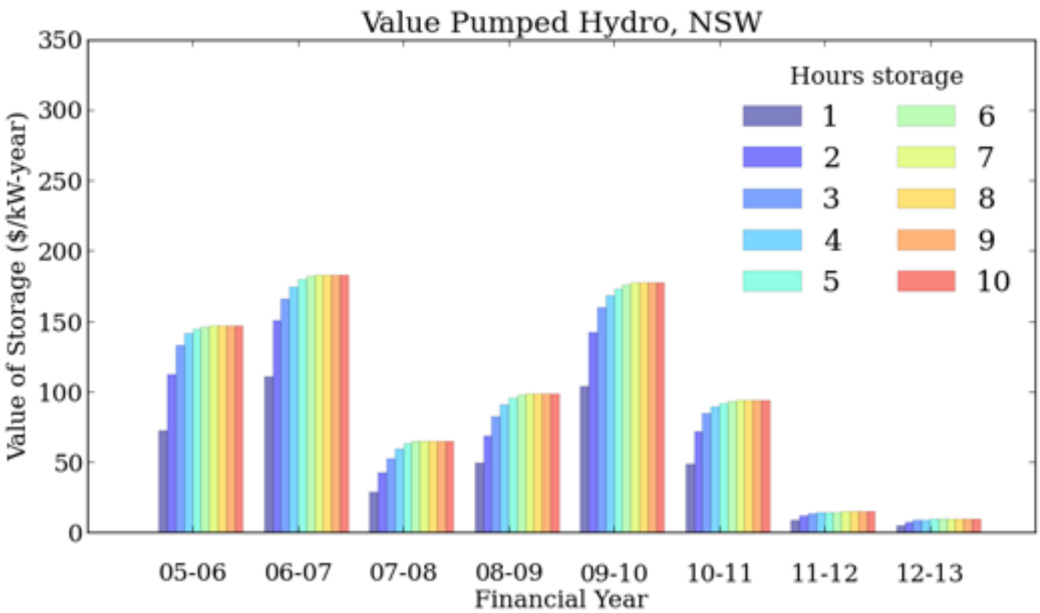


Figure 66: PHES arbitrage value index by financial year and storage capacity, for New South Wales. (MEI)

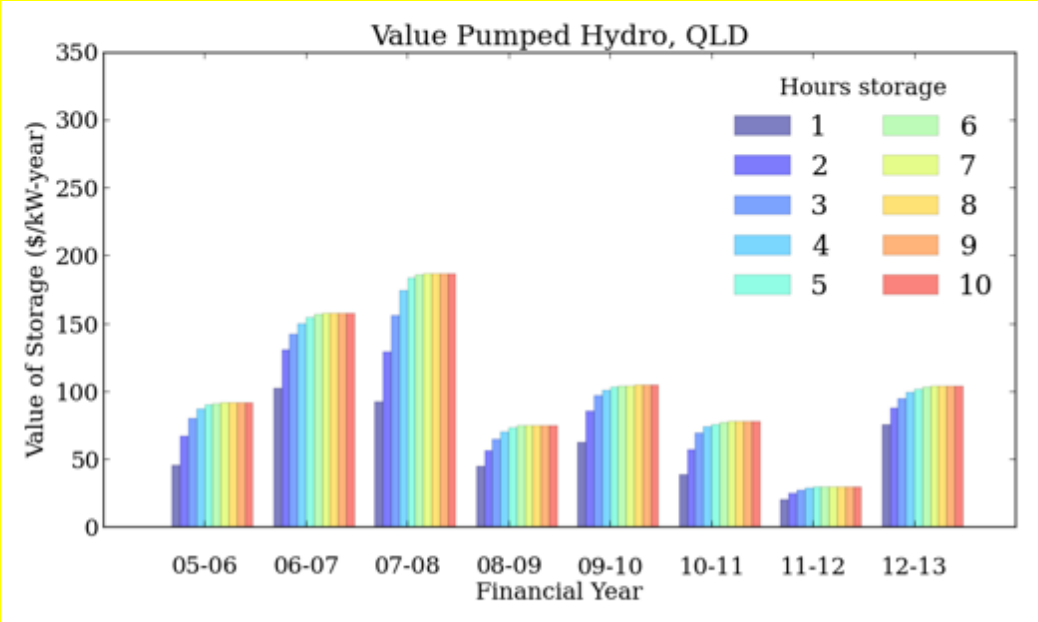


Figure 67: PHES arbitrage value index by financial year and storage capacity, for Queensland. (MEI)

Impact of forecast accuracy on arbitrage value

One of the weaknesses of the above-described basic arbitrage analysis is the assumption of 'perfect foresight' of energy prices. 'Perfect foresight' is not a realistic representation of an electricity market, considering the substantial uncertainty around short-term future electricity prices. In this report section, the value of the optimal dispatch assuming perfect foresight is compared with a more realistic approach to storage operation.

A variety of approaches are proposed for investigating more realistic strategies. Connolly et al. (2011) compares a 'historical strategy' and a 'prognostic strategy' with an optimal strategy. Sioshansi et al. (2009) uses a 'back casting' approach, based on historic prices for the previous two weeks. In MEI's analysis, pre-dispatch prices from the Australian Energy Market Operator are used. These price projections are generated approximately a day ahead of time, and thus this strategy is similar to the prognostic strategy employed by Connolly et al. (2011).

In MEI's optimization, the forecasted pre-dispatch prices for each half hour are used to determine the optimal operation within that current half hour period. This 'rolling window' approach is necessary due to the variable nature of the pre-dispatch prices, and because the pre-dispatch forecast become more accurate as the dispatch period approaches. Because this analysis technique is computationally expensive and the data set is limited, only one year was analysed.

Figure 68 compares the potential value of storage using pre-dispatch prices and perfect foresight. With six hours of storage, the strategy using pre-dispatch prices captures 85% of the potential value with perfect foresight. Sioshansi et al. (2009) found a similar "accuracy" using the back casting approach, and the Connolly et al. (2011) found their prognostic strategy achieved 81% of the optimal strategy profits.

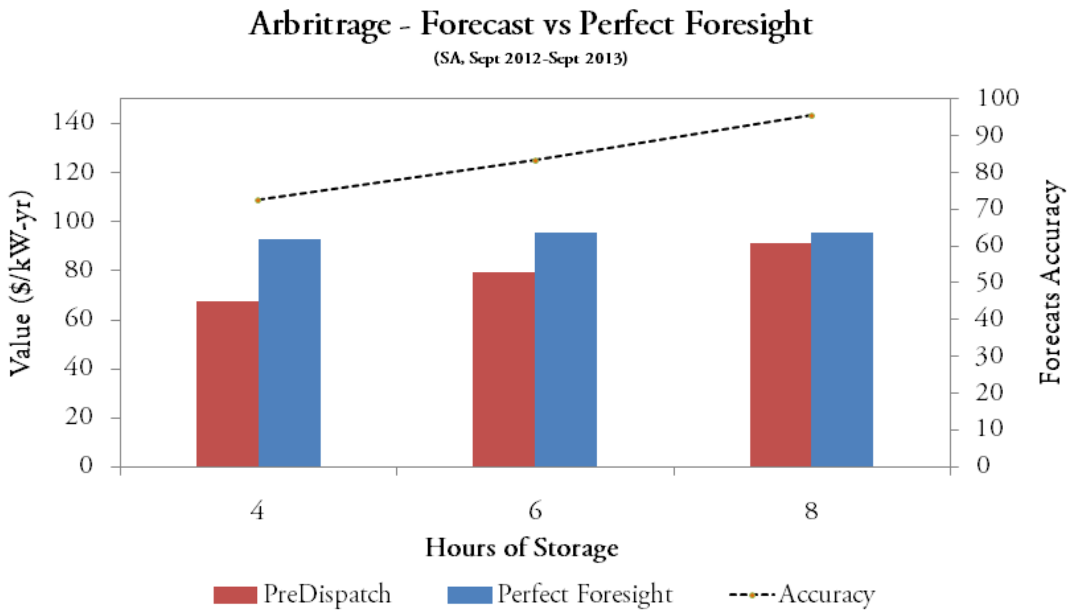


Figure 68: Forecast vs Perfect Foresight value comparison ($/kW-yr, left hand axis) and accuracy (%, right hand axis). (MEI)

This analysis also suggests that there may be additional value in storage beyond the six hours identified in the initial basic analysis. Increasing the storage appears to improve the realization of potential arbitrage value. This may be due to increased flexibility of a larger storage device, whereas the ability to re-evaluate and change operation may be constrained for smaller devices.

While the perfect foresight approach is unrealistic, it can be considered a theoretical upper bound. Further, based on the analysis of pre-dispatch prices (albeit limited) perfect foresight is a reasonable approximation of 'real', particularly as storage capacity increases.

How important is round-trip efficiency?

MEI's analysis shows the annual revenue distribution is highly skewed to a few days per year. This annual variation is a function of the underlying volatility (and magnitude) of the electricity prices in those years.

This revenue distribution has some unexpected consequences for a merchant storage facility. Since most revenue is generated on only a few hours per year, at very high prices, round-trip efficiency has virtually no impact on potential revenue. For example, consider purchasing cheap electricity (~ A$ 30/MWh) to then later sell at A$ 10,000/MWh. Even if the storage device round-trip efficiency was a very low 25%, buying four units of energy at $30 to sell one unit at $10,000 is still highly profitable (and only marginally less profitable than a 100% efficient device, where only one unit needs to be purchased).

This contrasts with Sioshansi et al., (2009), which found that round trip efficiency can have a significant impact on the arbitrage value of storage. Increasing the efficiency from 70% to 80% was found to increase revenue by 30%. The different results are a consequence of the different market structures. Unlike the PJM interconnection described by Sioshansi, the NEM does not have a capacity market. Rather, NEM price spikes provide similar incentives to the capacity market in the PJM. Since the PJM analysis does not include the capacity value of storage and models an energy market with a significantly lower price cap, a direct comparison cannot be made.

Need for further work regarding arbitrage value

In the NEM, a merchant storage facility (or generator) may face difficulties arranging finance, due to the high exposure to price and volume risks in the electricity market. A storage facility may be more successful in securing finance and managing these risks with a power purchase agreement (e.g. cap contracts). Storage devices in effect provide the same services (and compete) with open cycle gas generators, and are likely to use similar financial products to manage the risks. Further work that analyses the impacts of hedging risks and cap contracts on arbitrage value would be useful.

Another limitation of the MEI techniques described here is the use of static prices. A large-scale storage device (for example pumped hydro) would be expected to have an impact on the electricity market and prices. The Sioshansi et al., (2009) analysis found that a modest rated capacity of storage (0.7% peak load, 1.2% average load) reduced the value of storage arbitrage by as much as 10%. Further work considering the impact dynamic pricing has on the arbitrage opportunity in South Australia would be beneficial.

Analysis from the USA (Sioshansi et al. 2009 and Sioshansi 2010) suggests that arbitrage and load-shifting results in consumer surplus gains and associated decreases in costs to end users.
This corresponds with producer surplus loss and is a wealth transfer from generators to consumers. In those studies, the increased consumer surplus was found to be greater than producer surplus losses, suggesting net social welfare gains. Further work is needed to investigate these additional benefits and welfare effects for Australian electricity market regions.

The preceding analysis considers only the energy arbitrage value. Storage can also provide benefits such as:

- improved use of existing generation, transmission and distribution assets
- deferred investment in network assets and new generation
- helping to integrate renewable energy resources into the power system
- participation in ancillary service markets.

12. MEI economic payback modelling: PHES stand-alone and co-located with wind

This section describes MEI modelling that investigated, for the seven case-study sites described above, the economic payback of stand-alone PHES facilities and PHES facilities co-located with a wind farm.

The optimum sizes of co-located PHES facility and wind farm components were determined that would minimise payback time in electricity transmission-constrained scenarios. These simulations varied the size of facility components (water reservoir, hydro turbine, and wind farm) in order to find the minimum payback period, assuming that the facilities would be co-located and connected to the electricity grid via a transmission line set at a fixed capacity of 200 MW.

Hour-by-hour modelling was done for two-year periods that aligned actual South Australian wholesale electricity price data with site-specific wind speed data.

Cost basis and site locations

The cost of the 200 MW transmission line was based on electricity transmission facility cost data from the Australian Energy Market Operator (AEMO 2012) as described here:

- the transmission line from the nearest transmission trunk to the site was costed at A$ 0.7 million/km
- a fixed cost of A$ 20 million total was applied for two substations (one at each end).

MEI assumed wind turbine costs of A$ 2 million per MW of installed wind generation capacity.

MEI applied the PHES component costing models described earlier in this report to the seven case-study sites in South Australia and western Victoria. These sites are listed in Table 3 along with their latitude, longitude, net head, wind farm capacity factor, and distance from the site to the electricity grid.

Table 3: Input data for optimisation of selected sites

	Latitude	Longitude	PHES net head (m)	Wind farm capacity factor (unconstrained)	Distance to electricity grid (km)
East Eyre 2-A	-34.5	135.4	53	38 %	53
East Eyre 2-B	-34.4	135.4	114	38 %	53
East Eyre 3	-34.4	135.4	121	38 %	53
El Alamein	-32.6	137.7	287	27 %	2
Fleurieu 3	-35.5	138.2	171	43 %	45
Portland	-38.4	141.4	125	46 %	12
Yorke 1	-34.2	138.0	88	30 %	5

MEI PHES-wind facility optimisation model description

The MEI PHES-wind facility optimisation model, outlined in Figure 69, was programmed to decide on an hour-to-hour basis whether to:

- dispatch electricity onto the grid directly from the wind farm,
- store the wind-generated electrical energy in the PHES reservoir,
- release water from the PHES reservoir to generate power,

or

- take power off the grid and store it with the PHES facility.

The dispatch decision was influenced by the amount of electricity that could be produced by the wind farm, the amount of water stored in the reservoir and the price of electricity. When electricity prices are low, the model will try to store energy if possible. When prices are high, the model will aim to dispatch electricity. The model logic is.

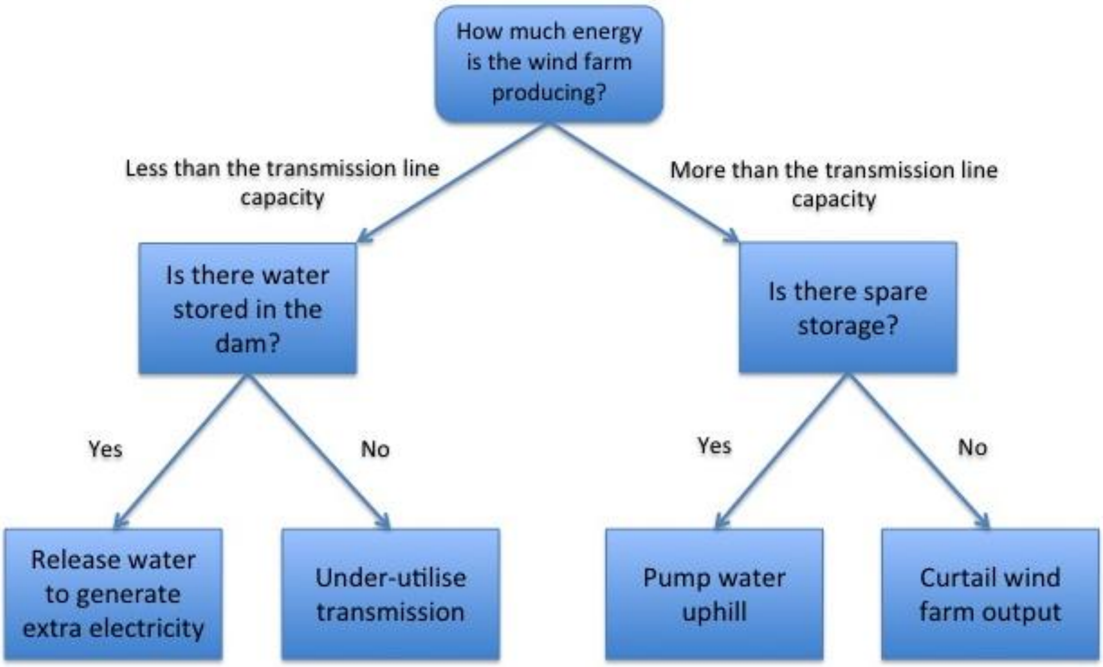


Figure 69: Energy system model flow diagram. (MEI)

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Wind data input

MEI's model simulates electricity produced by the wind farm at one-hourly resolution for the two-year period 2010 to 2011. To calculate the amount of wind-generated electricity available at each point in time, the output from the Australian Community Climate Earth System Simulator (ACCESS-A) is used. The Australian Bureau of Meteorology uses this model for its weather forecasts.

ACCESS-A assimilates vast amounts of meteorological data from in situ and remotely sensed platforms including wind speed, surface pressure, humidity and temperature. The output is therefore a combination of the observations and ACCESS-A's mathematical description of the dynamics of the atmosphere.

ACCESS-A output gives complete coverage over Australia so that estimates of wind speeds can be obtained in areas that currently do not have in situ observations. The horizontal resolution of ACCESS-A is 12 km. Wind speeds depend on local topography and there is considerable variability in wind speeds at resolutions below 12 km.

The ACCESS-A model data is available for elevations of 10, 50 and 130 metres above ground-height. MEI interpolated this data to 80 metres above the ground to simulate the typical hub height of a wind turbine. The wind speed data was converted to electricity output using the power curve for a General Electric 2.5 MW turbine (rotor diameter = 100 metres) with a cut-in speed of 4 metres per second reaching maximum output at 13 m/s and a maximum wind speed threshold of 25 m/s. (This wind speed was never attained in the locations or time period examined in this study).

The seven case-study sites present a broad range of wind resource quality, ranging from a capacity factor of 27% for El Alamein to 46% for Portland. A 27% capacity factor is commercially interesting and a 40+% capacity factor indicates a world-class wind resource. This explains why there are already wind farms installed along the South Australian coast.

Other modelling input data, assumptions, and methodology

Actual historical hourly electricity price data for the following time periods was sourced from the databases of the Australian Energy Market Operator for the South Australia electricity market region:

- the two-year period 2008-2009
- the two-year period 2010-2011.

MEI expected that the simulation results for these two two-year periods would differ because of the higher number of high price events that occurred in 2008-2009 versus the later years.

Because wind data for the years 2008 and 2009 was not available to this study, wind data for the years 2009 and 2010 was aligned to the electricity prices (hour by hour) for both two-year periods.

Two different renewable energy certificate (REC) values were applied to the wind farm output: A$ 0/MWh and A$ 30/MWh).

PHES round-trip efficiency of 80% was assumed. Therefore a price differential of at least 25% is required before the model will begin to run the pumps.

The dispatch model looks 48 hours into the future and will at times defer pumping or generating to take maximum advantage of upcoming price events. As described in earlier sections of this report, MEI's modelling assumes perfect foresight of electricity prices, and that the impact of dispatching or drawing power from the grid has no impact on the market price.

The simple payback time, calculated in years, is the number of years of revenue needed to equal the capital expenditure. No taxation effects were modelled nor were any time-value-of-money factors (discount rates) were applied.

Modelling results

Combined PHES and wind model operational behaviour

Figure 70 shows the MEI-modelled behaviour of a wind and PHES facility in the days leading up to a high-electricity-price event. On Day 12, the model fully dispatches the energy stored in the water reservoir and then recharges in two stages over the following two days without any generation in between. This behaviour ensures that all potential storage is available for the high price event ($12,000/MWh) that occurs on Day 19.

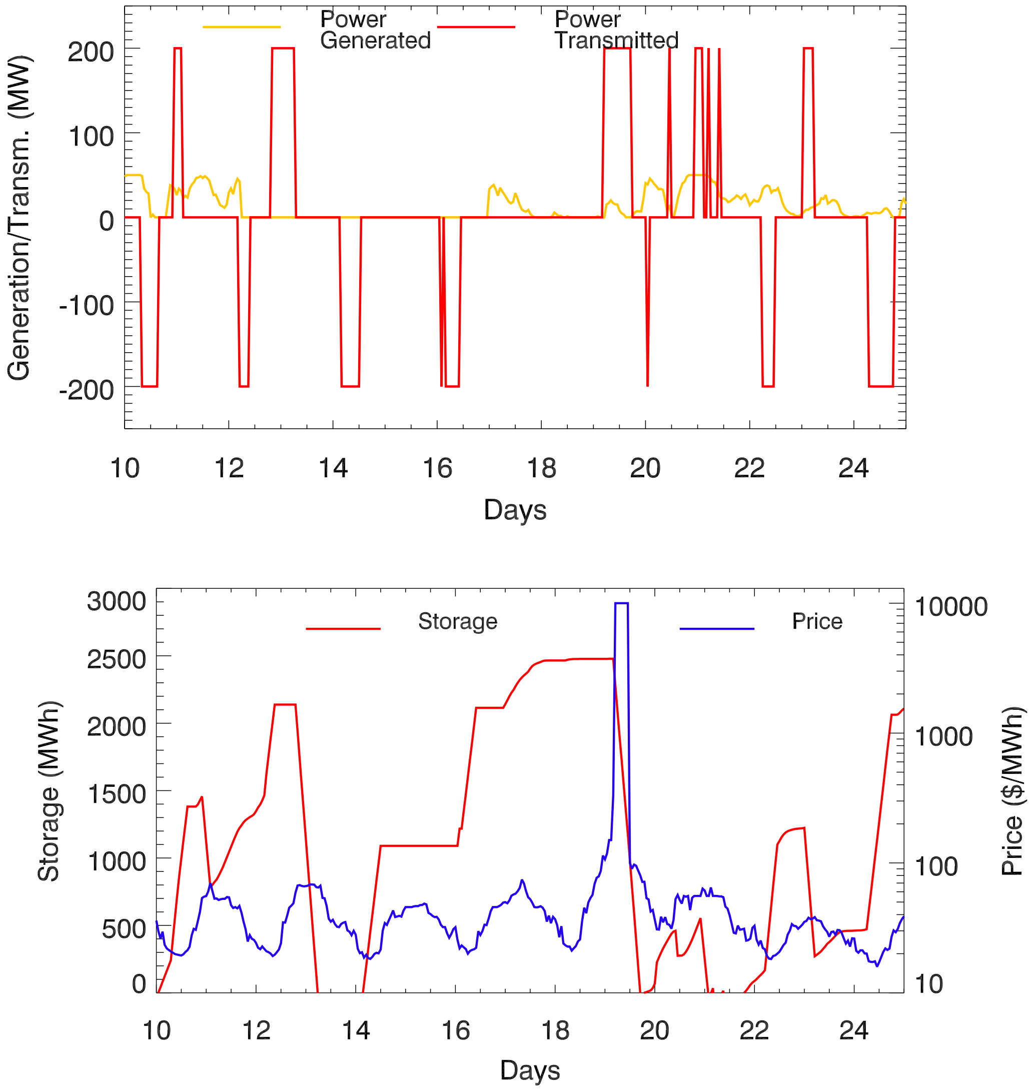

Figure 70. Example output for the Yorke 1 site: 2,500 MWh of storage, 200 MW hydro turbine, 50 MW wind farm. This combination yields a simple payback period of 14.7 years. (MEI)

PHES-only economic return

The results for the seven case-study sites with PHES-only (no wind) are shown in Figures 71 and 72.

Figure 71 shows that simple payback ranges from 8 to 16 years for five of the sites. The simple payback period is longer for Yorke 1 (which was arbitrarily assigned a high capital cost) and East Eyre 2-A (which has low net head).

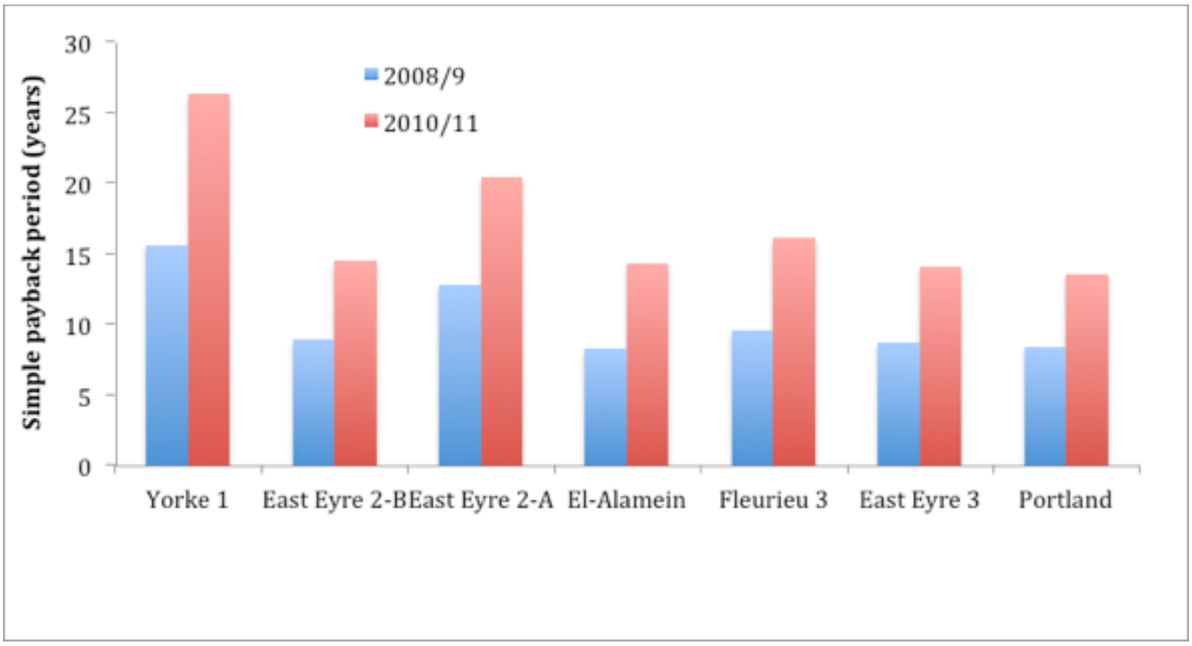

Figure 71: Simple payback period for PHES-only (no wind farm) simulations for the two-year period 2008 to 2009 and the two-year period 2010 to 2011.

For all sites, payback periods are lower when the modelling is based on the two-year period 2008-2009. This is because in these years there were several high price events in the South Australian electricity market region that generated significant income. In the two-year period 2010 to 2011, the actual electricity prices (upon which this modelling was based) were suppressed with few very hot days occurring in those years.

Figure 72 demonstrates the importance of high price events on PHES facility income. Results for the two-year period 2008-2009 are shown.

The blue line shows that the value of energy (price multiplied by power dispatched) is highly variable, usually sitting close to $0/hour, but spiking to $2 million/hour for brief periods associated with high price events ($12,000/MWh).

The cumulative income line (shown in red) illustrates that most income is earned during these extreme price events and that in 2009 only one high price event occurred (around Day 400).

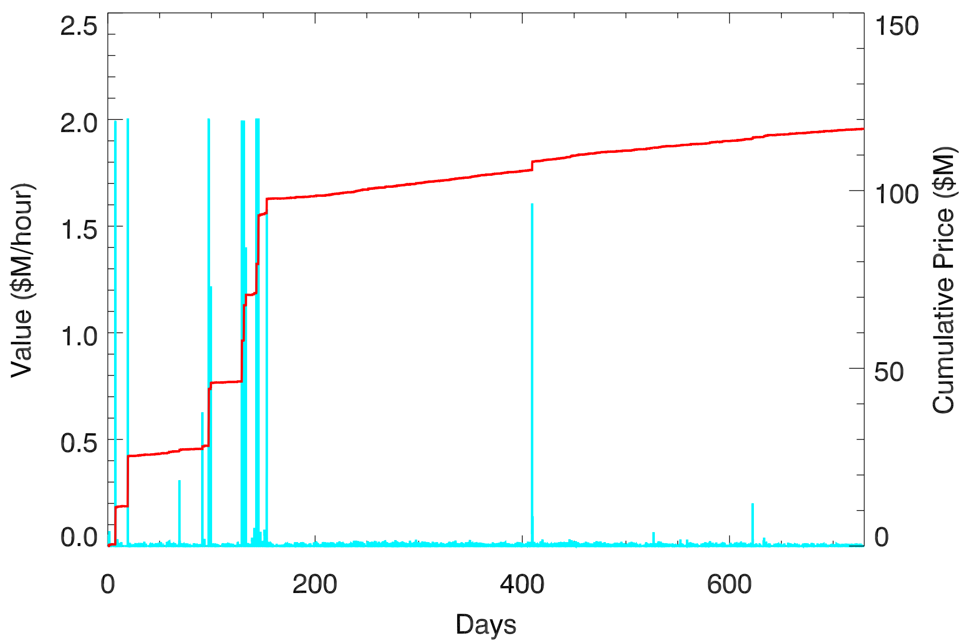

Figure 72: Value of generation in $million/hour (blue line) and cumulative revenue ($million) (red line). (MEI)

Modelling results for combined PHES and wind facilities

The results from the second set of simulations are shown in Table 4 through 7. Here the model was used to simulate power generation for a broad range of hydro turbine and storage reservoir sizes in combination with various wind farm configurations.

The results in Table 4 are for simulations that apply 2008-2009 prices and no REC value for wind. For most sites, the ideal PHES/wind farm combination was a 200 MW hydro turbine and ~ 12 hours of storage coupled to a wind farm of 50 MW. The exception is the El Alamein site where the poor wind resource makes installing a wind farm there an unattractive option. Simple payback periods range from 8 to ~ 15 years.

Table 4: Simulation results for PHES / wind farm combinations: 2008 to 2009 electricity prices, REC price = $A zero.

Site	Storage (MWh)	PHES generation capacity (MW)	Wind generation capacity (MW)	Payback period (years)
Yorke 1	2,500	200	50	14.7
East Eyre 2-B	2,250	180	50	8.7
East Eyre 2-A	2,250	180	50	11.8
El-Alamein	2,750	220	0	8.3
Fleurieu 3	2,500	200	50	9.3
East Eyre 3	2,250	180	50	8.5
Portland	2,250	180	50	8.0

The results in Table 5 are for simulations that apply 2008-2009 prices and an A$ 30/MWh REC value for wind. On comparing these results to those given in Table 4, there is a shift towards wind-only installations with no pumped hydro. As the REC value only applies to wind farms and not to energy produced by pumped hydro, the higher REC value gives an advantage to the windier sites.

Table 5: Simulation results for PHES / wind farm combinations: 2008 to 2009 electricity prices, REC price = $A 30/MWh.

Site	Storage (MWh)	PHES generation capacity (MW)	Wind generation capacity (MW)	Payback period (years)
Yorke 1	0	0	200	9.8
East Eyre 2-B	0	0	200	7.8
East Eyre 2-A	0	0	200	7.8
El-Alamein	3,000	200	50	8.1
Fleurieu 3	0	0	200	7.2
East Eyre 3	0	0	200	7.8
Portland	0	0	200	6.1

The results in Table 6 are for simulations that apply 2010-2011 prices and no REC value for wind. Given the infrequency of actual high price excursions over the two-year period 2010-2011, there is less incentive to take advantage of PHES and the locations with good wind resources tend to deploy wind farms only. Payback periods are longer versus the results shown in Table 4.

Table 6: Simulation results for PHES / wind farm combinations: 2010 to 2011 electricity prices, REC price = $A zero.

Site	Storage (MWh)	PHES generation capacity (MW)	Wind generation capacity (MW)	Payback period (years)
Yorke 1	0	0	200	14.9
East Eyre 2-B	1,750	200	0	14.5
East Eyre 2-A	0	0	200	16.4
El-Alamein	3,000	200	0	14.3
Fleurieu 3	0	0	200	13.7
East Eyre 3	1,750	200	0	14.1
Portland	0	0	200	12.5

The results in Table 7 are for simulations that apply 2010-2011 prices and an A$ 30/MWh REC value for wind. Compared to the results given in Tables 4 through 6, the shift away from storage is complete. In Table 7, None of the sites deploy PHES and instead achieve the shortest payback periods possible by simply deploying a wind farm sized to take maximum advantage of the 200 MW transmission capacity available.

The payback period in these simulations strongly depends on the quality of the wind resource. Therefore, Portland and Fleurieu 3 (40+% wind farm capacity factors) have the shortest payback periods.

Table 7: Simulation results for PHES / wind farm combinations: 2010 to 2011 electricity prices, REC price = $A 30/MWh.

Site	Storage (MWh)	PHES generation capacity (MW)	Wind generation capacity (MW)	Payback period (years)
Yorke 1	0	0	200	9.5
East Eyre 2-B	0	0	200	9.5
East Eyre 2-A	0	0	200	9.5
El-Alamein	0	0	200	10.0
Fleurieu 3	0	0	200	8.1
East Eyre 3	0	0	200	9.5
Portland	0	0	200	7.4

A key finding from these combined PHES/wind farm simulations is that the model tends to favour either:

- a large PHES facility (with a small wind farm where the wind resource is excellent),

or

- a large wind farm,

whereas the combination of PHES and a large wind farm does not occur. This is probably because of the limited transmission capacity assumed in the simulations. For example, if electricity prices happen to be high at times when the wind is blowing, there is no transmission capacity available to dispatch the stored energy.

The conclusion is that when electricity transmission constraints apply, wind farms and large-scale energy storage systems should not necessarily be co-located. The best PHES sites are best used for storage while the best wind sites are used for wind farms.

Simulations of multiple sites and their simultaneous operation were beyond the scope of this study.

13. Inclusion of PHES in high-penetration renewable energy scenarios

A recent study by the Australian Energy Market Operator (AEMO 2013) found that it is technically feasible to supply 100% of the eastern states' electricity with renewable energy technologies and resources. In the scenarios modelled by AEMO for the 2030 and 2050 target years, different mixes of renewable electricity generation technologies were employed.

In AEMO's modelled cases, stored energy equivalent to 100 to 200 GWh of electricity was required in order to maintain reliable supply during periods of low wind and/or sun. This need for stored energy was met by combinations of:

- existing conventional hydroelectricity generation
- existing pumped hydroelectricity generation
- biomass and biogas
- solar thermal storage.

Due to the high PHES costs input to the modelling (ROAM 2012) relative to other technologies, no new PHES was selected for AEMO's final modelled solutions.

However, MEI's findings and the PHES costings documented in this report might lead to different results in any future electricity system-wide modelling. One hundred GWh of stored energy could be supplied by, for example, twenty 5,000 MWh PHES reservoirs (500 MW generation capacity each) that are approximately 30 metres deep and one kilometre wide, with 100 metres of net head. Assuming a unit capital cost of A$ 200,000/MWh, one such PHES facility would cost A$ 1 billion.

14. Future work

Suggested future work required to progress the deployment of PHES in Australia and elsewhere include:

- **consultation** with key government, electricity industry, and energy consuming stakeholders
- assessment of **legal and regulatory barriers** to pumped hydro and other energy storage technologies
- assessment of pumped hydro energy storage (PHES) **arbitrage value** in Australian electricity markets
- assessment of the impact of different scales of PHES deployment on **wholesale energy prices**, including price spikes caused by heat waves and other events
- investigation of current and future-expected **electricity transmission and grid-operation constraints** (with growth in renewables) in regions near potential PHES sites
- assessment of how PHES can provide **grid-operation benefits** and complement the expansion of renewable energy while obviating investment in electricity transmission and grid management infrastructure
- assessment of **seawater "turkey nest"-**type PHES technology and the potential for modernisation, including further communication with J-Power
- application of MEI's terrain and cost-based mapping to **identify specific sites** for PHES in Australia, also considering current land ownership, competing land-uses, sea water supply, geotechnical
- development of more accurate PHES **cost estimates**, with input from local and overseas engineering, construction, and equipment-supply firms
- economic analysis of PHES versus other **competing** energy storage technologies
- commercial **project economic analysis**.

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