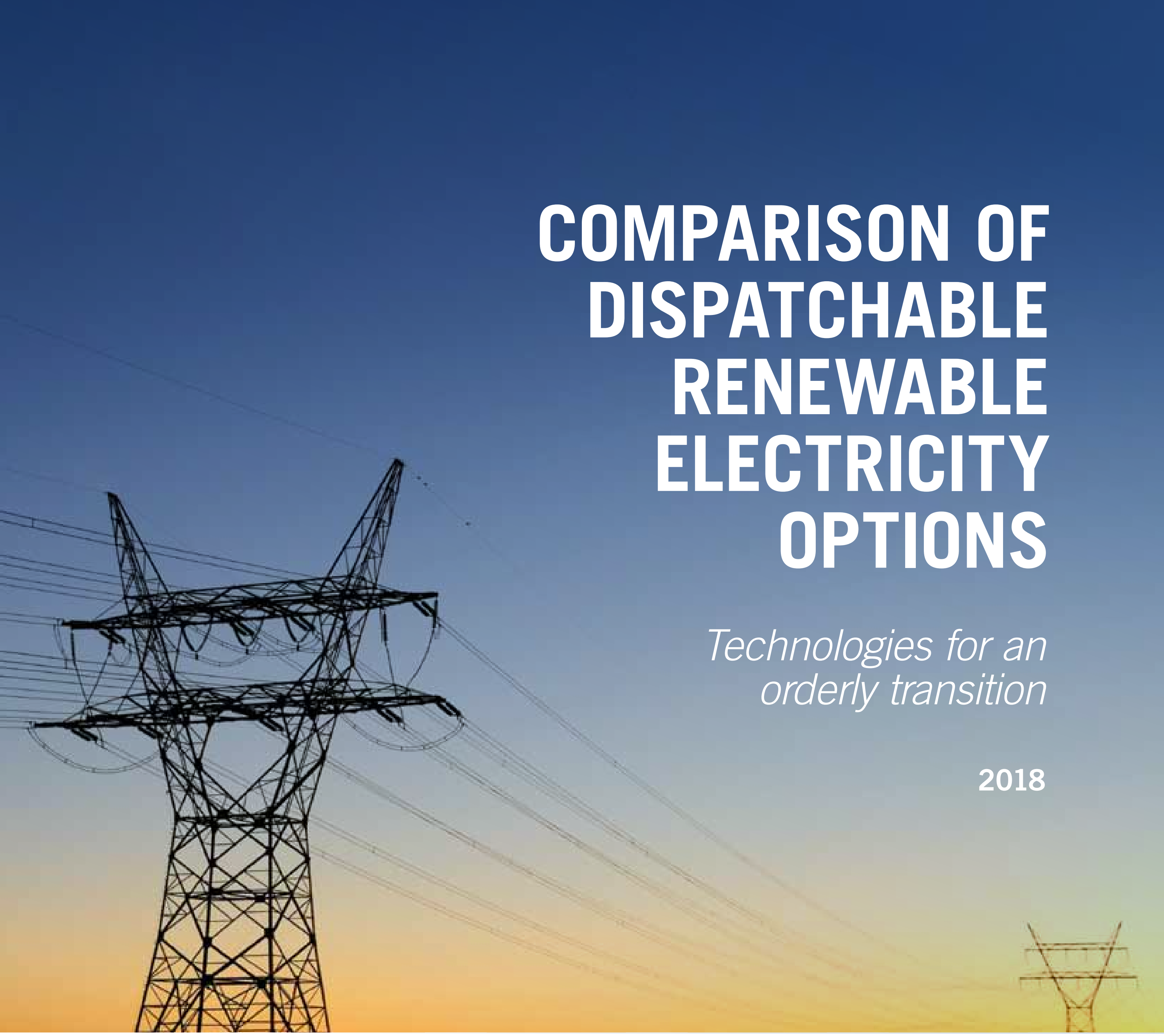

COMPARISON OF DISPATCHABLE RENEWABLE ELECTRICITY OPTIONS

Technologies for an orderly transition

2018

itp

ITK

Institute for Sustainable Futures

Prepared for

ARENA

Australian Government
Australian Renewable Energy Agency

ABOUT ARENA

ARENA was established by the Australian Government to make renewable energy technologies more affordable and increase the amount of renewable energy used in Australia. ARENA invests in renewable energy projects, supports research and development activities, boosts job creation and industry development, and increases knowledge about renewable energy. ARENA is currently supporting more than 200 projects and is actively seeking new projects to support.

ARENA

Australian Government
Australian Renewable Energy Agency

ABOUT THE TEAM

The ITP Energised Group (ITP) was formed in 1981 and is a specialist renewable energy, energy efficiency and carbon markets engineering and consulting group of companies. It has member companies and offices in the UK, Australia, India and China and has completed projects throughout the world.

The Institute for Sustainable Futures (ISF) was established by the University of Technology Sydney in 1996 to work with industry, government and the community to develop sustainable futures through research and consultancy. ISF's mission is to create change toward sustainable futures that protect and enhance the environment, human well-being and social equity.

ITK Consulting (ITK) specialises in analysis of electricity, gas and carbon markets. It offers insights into valuations, demand and supply, industry structure, trends and policy analysis. Research is based on 33 years of stockbroking research experience. Clients include government organisations and businesses operating in the Australian electricity and gas industry.

Comparison of dispatchable renewable electricity options

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ABOUT THIS REPORT

The Australian Renewable Energy Agency (ARENA) commissioned a team lead by the ITP Energised Group working with The Institute of Sustainable Futures and ITK Consulting to examine the various options for providing dispatchable renewable electricity generation.

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ITP Thermal

Keith has worked in Renewable energy systems engineering, research and policy advocacy since 1987. Including 15 years teaching at the ANU as leader of the Solar Thermal Group.

Jay Rutovitz
Research Director
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Jay has worked in renewable energy and energy efficiency since 1994. She has a long standing interest in bioenergy, integrating renewables into the wider energy system and develop ping appropriate market structures for the ongoing energy transformation.

Geoff James
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Geoff's research and consulting interests included demand management, integrating renewable generation, distribution network evolution, transmission planning, energy market development, and energy storage technology and applications.

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Muriel has worked on renewable energy research, education and policy since 1980. Past appointments include Associate Professor, PV and Renewable Energy Engineering, University of NSW; Chair, Australian PV Institute; Australian representative, and IEA PV Power Systems program.

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David is the principal of ITK a small consultancy specialising in analysis of the electricity and gas industry and the implications of decarbonisation of the Australian and Global economy.

Joe Wyder
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Joe manages a range of energy policy, feasibility studies and deployment projects. His experience includes work on renewable generation and energy efficiency projects in remote locations in Australia and the Pacific.

Annie Ngo
Senior Consultant
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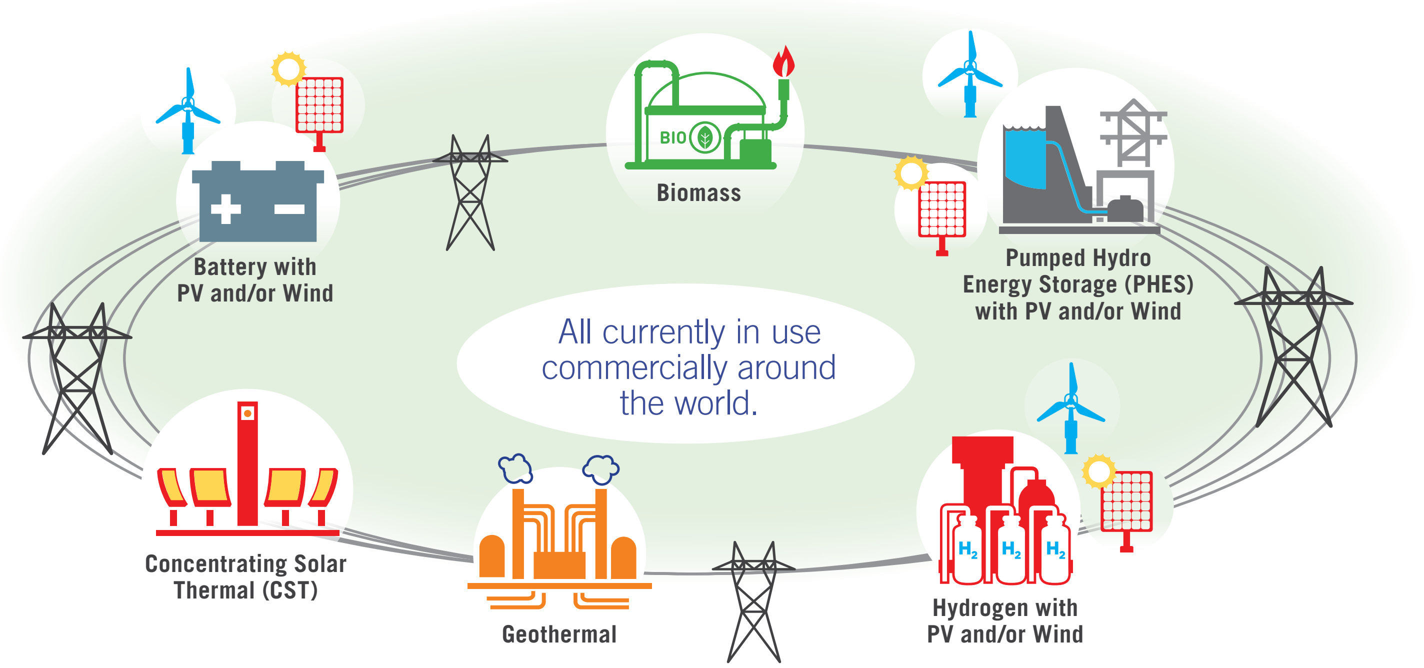
Annie has over a decade of experience in the Australian energy sector in specialist advisory roles to government and industry. In these roles she has provided advice on energy policy, regulation and market development.

DISPATCHABLE RENEWABLE ELECTRICITY

WHAT IS DISPATCHABLE RENEWABLE ELECTRICITY?

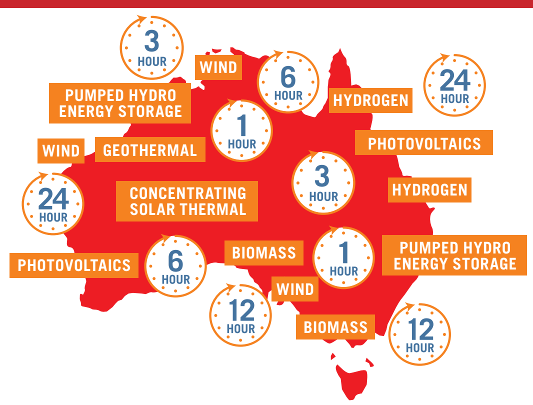
Renewable energy power plants or that can vary output (up or down) at the command of the operator.



HAVING SOME DISPATCHABLE ELECTRICITY IS ESSENTIAL

MIX OF

Technologies
Locations
Durations



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EQUALS

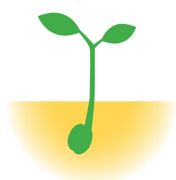
Least cost ✓
Least risk ✓
Orderly transition ✓

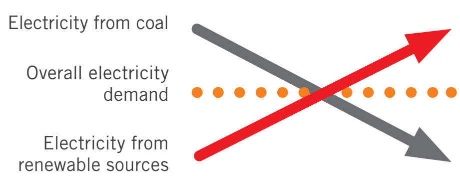
COST VS VALUE

Dispatchable renewable energy costs more than variable renewable energy but is considerably more valuable.

ACHIEVABLE GROWTH

Achievable growth rates could keep pace with coal retirements and enable an orderly transition to a large share of Renewable Energy.



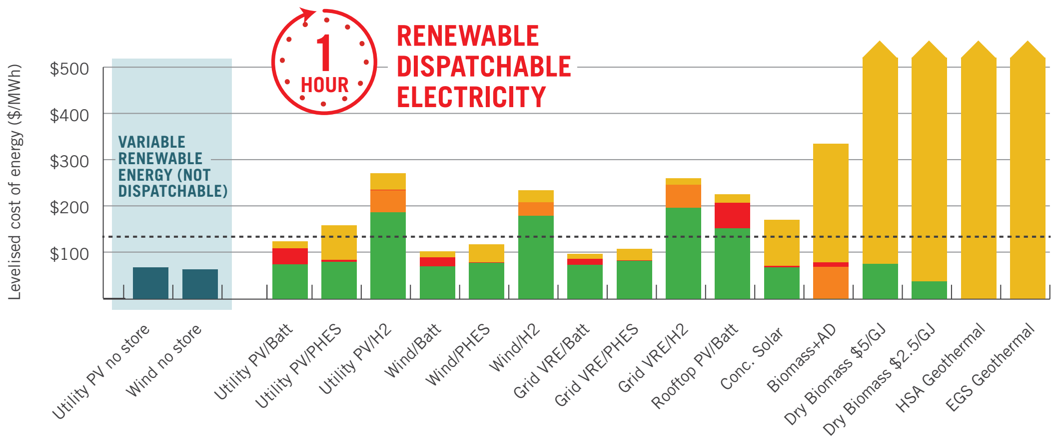


LONG TERM

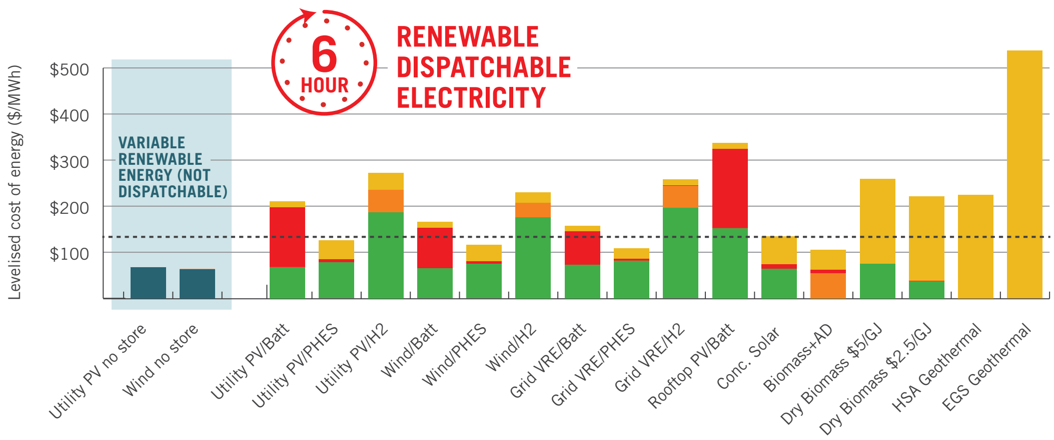
In parallel, long term energy reserves can be added to ensure generation in critical periods.

COMPARING COST OF ELECTRICITY

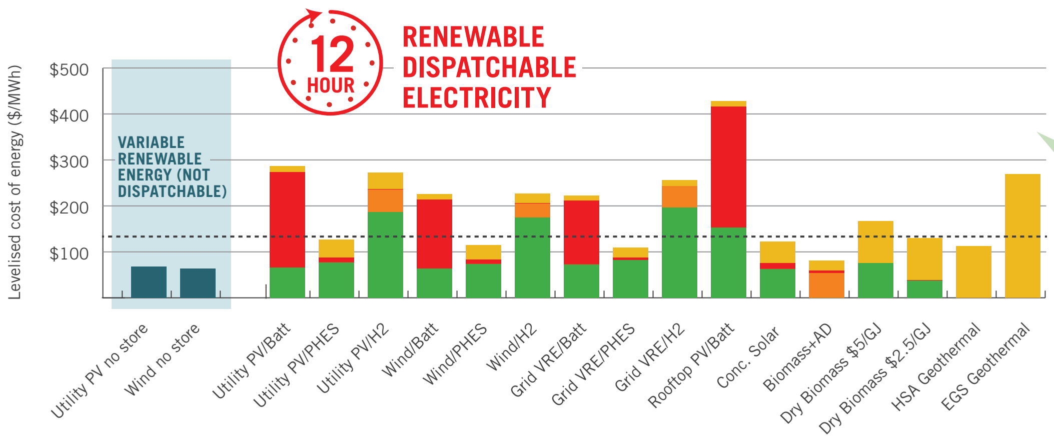
Levelised Cost of Energy (LCOE) for the different combinations at zero, one, six and twelve hours of storage or duration of delivery for systems at 100MWe nominal capacity evaluated with a 6.5% weighted average cost of capital.



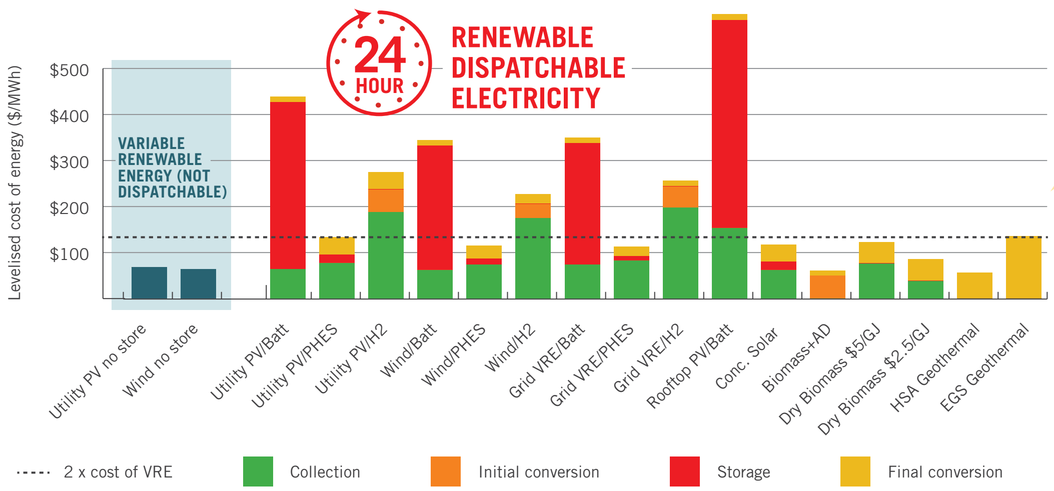
Figures show the contributions to LCOE for each of the collection, initial conversion, storage and final conversion subsystems in each case.



For each timescale there are **multiple cost competitive options** below the line representing 2 x the cost of VRE



For each timescale different technologies are seen to offer the **lowest cost energy**

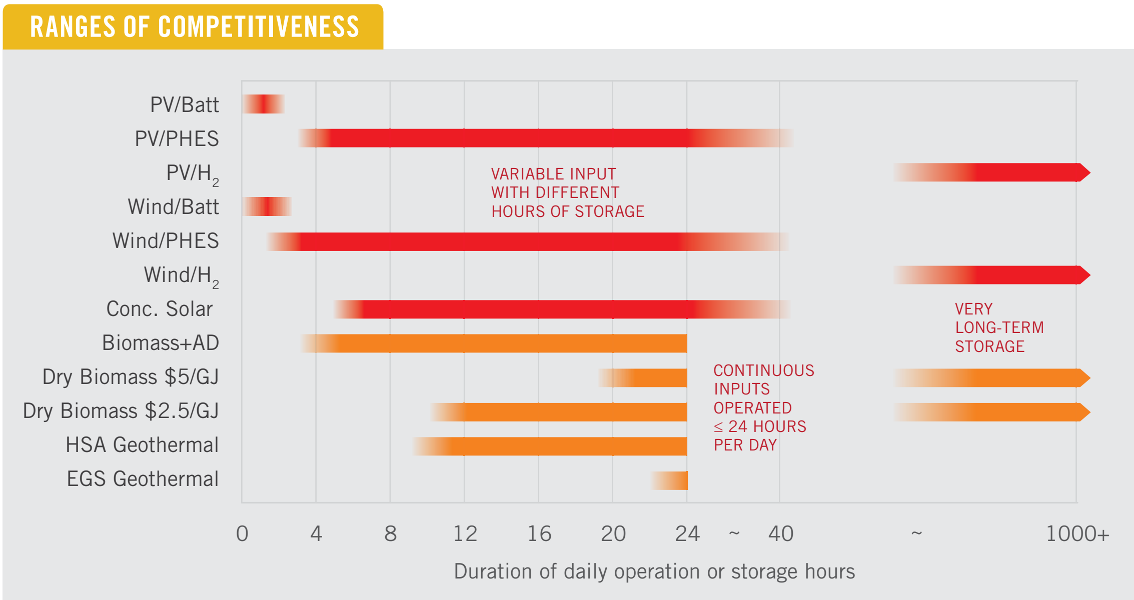


Each technology has timescales and configurations for which it is best suited.

EXECUTIVE SUMMARY

Key Findings

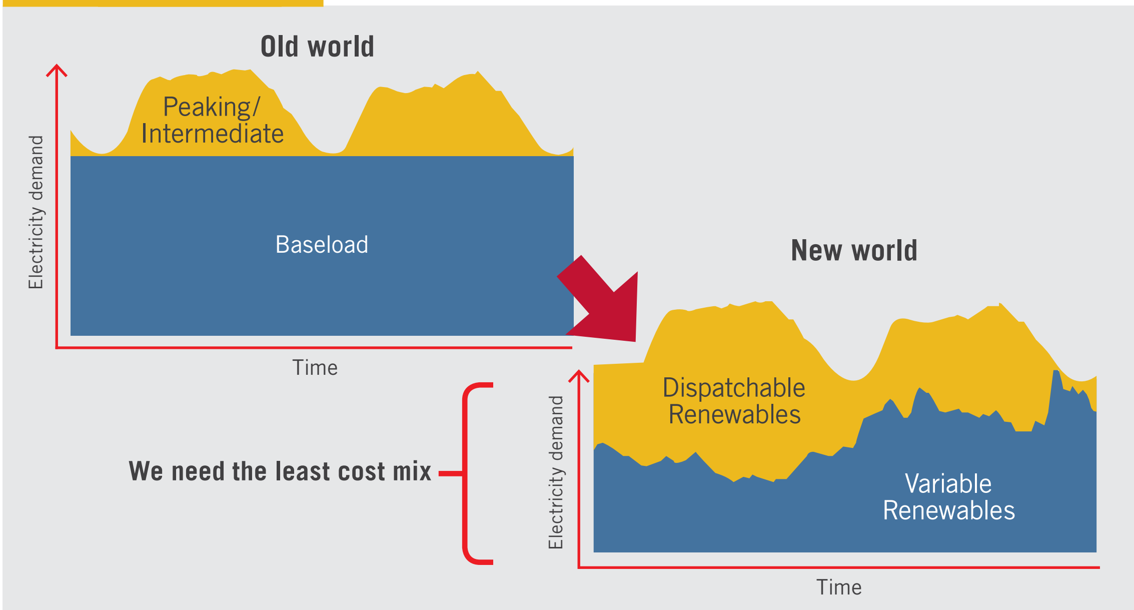
- There are multiple affordable options for firm dispatchable renewable electricity generation over all timescales at one and a half to two times the cost of variable renewable energy (VRE) when used regularly.
- The dispatchable renewable options of; PV or wind driven batteries, pumped hydro energy storage (PHES) or hydrogen; concentrating solar thermal; bioenergy and geothermal all have a role to play. There is no single winner, and at each timescale there are multiple options that fall within a general least-cost band.
- The likely least-cost future electricity system solution is a mix of both variable and dispatchable renewable technologies, durations and locations with an average cost of electricity considerably lower than dispatchable generation alone.
- Additional, long term energy reserves can be added to a generation system to ensure generation in critical periods at two to three times the cost of VRE alone in critical periods.
- The cost of electricity from dispatchable renewable generation is comparable with estimates for new build gas while avoiding the associated fuel and carbon price risks.
- For a small number of events per year, emergency demand response is more cost effective than a dedicated dispatchable renewable generation option used infrequently.
- A level of short-term firmness could be obtained cost effectively during high VRE generation periods by curtailing and controlling output levels from PV or wind.
- Costs are likely to continue to fall in real terms for all renewable energy technologies in correlation with their growth in global deployment. This will improve the competitive position of dispatchable renewables compared to gas. The other findings above are likely to remain valid as this occurs.
- Readily achievable growth rates of around 25% per year in dispatchable renewables could keep pace with coal retirements and enable an orderly transition to a large share of renewable energy.



Introduction

As Australia moves towards a low emission electricity system, there is a need to better understand the various technology combinations for dispatchable renewable electricity generation to contribute to system reliability. With variable renewable energy (VRE) generation from wind or photovoltaic (PV) systems now the cheapest electricity per MWh for new build systems, there is a shift from an old world of baseload coal balanced by open cycle gas turbines and hydro, to a new world with increasing levels of VRE balanced by dispatchable renewable generation.

SYSTEM IN TRANSITION



Dispatchable generators are those that can raise or lower power output on command from the system operator or facility owner. Some dispatchable generators are more flexible (faster in response) than others. Another key concept is 'firm generation', which is a constant level of power output that a generator can legally or commercially guarantee for a specified time interval.

This study identifies and compares commercially available options for providing dispatchable electricity generation from renewable sources. It examines the sensitivity of energy cost to configuration and the applicability of various technologies to different roles. The focus is on providing electrical power when needed. While an underlying assumption is that some significant fraction of power generation capacity needs to be dispatchable, this study has not analysed the amount of dispatchable capacity that would be required to manage a future electricity system, rather it provides consolidated cost information that can be used in such studies.

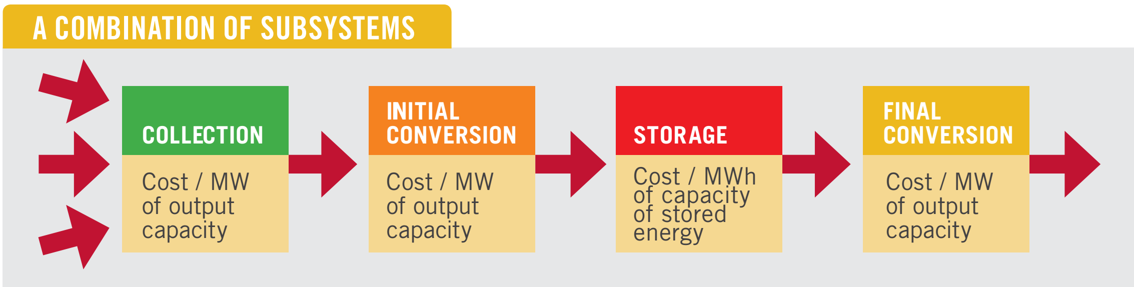
Consistent renewable energy sources such as bioenergy and geothermal are inherently dispatchable, while VRE inputs such as wind or solar energy can be converted to dispatchable generation when combined with some form of energy storage. The energy storage technologies considered in this study are batteries, pumped hydro, hydrogen and molten salt. Such storage could be co-located or based elsewhere in the system with a virtual or contractual 'connection'. A small amount of storage allows energy from a variable resource to be sent out in a firm and dispatchable manner when the input is available. If more storage is applied the result is a firm and dispatchable system that can either extend or even shift its delivery of energy for some time after the variable input has fallen off. If such a storage is fully charged and the variable input continues, energy must be sent out or lost. When the variable input has fallen away, energy in storage can be dispatched in a higher value strategic manner.

In the case of inherently dispatchable technologies like bioenergy or geothermal, deliberately reducing hours of operation with some form of buffer storage of the resource as appropriate can allow higher power output at reduced but targeted times, which may be of higher strategic value.

Although much of the current public debate is around issues of electricity system security to avoid large-scale blackouts due to technical issues, recent studies suggest this is relatively easy to address and only becomes a problem when neglected. The emphasis of this study therefore is on addressing the provision of electricity when it is most needed (overall reliability), which appears to be the issue that will require the greatest long-term planning and investment. Many of the technology options investigated can also provide ancillary services, so it is likely that if the timely delivery of energy is addressed using the technology options investigated, a mix of renewable energy technologies will also be able to maintain system security.

Installed costs

In this study dispatchable renewable generation combinations have been modelled as a combination of subsystems.



These are: energy collection (e.g. PV array or wind farm, heliostat field, biomass resource etc.), initial energy conversion (e.g. electrolyser or power conditioning prior to storage), energy storage (e.g. battery cell, molten salt tank, dam etc.) and final energy conversion (e.g. boilers and turbine, inverters etc.).

Cost information for real projects has been collected from published sources and stakeholder consultations and then fitted to subsystem-based models with the addition of a size dependence[1], to give the results in the tables below for fully installed systems in Australia at the end of 2017.

1 Cost proportional to size to the power n, where the exponent n is less than 1 and often around 0.7. A value less than one indicates an economy of scale applies as size is increased.

Parameter values for variable renewable generation	Specific installed cost	Baseline capacity	Power law size exponent
PV utility-scale	$1.87m/MW_e$	100MW_e	0.89
Rooftop PV	$2.00 m/$MW_e$	0.01MW_e	1
Wind	$2.18 m/$MW_e$	100MW_e	0.9

Parameter values for electricity storage	Specific installed cost	Baseline capacity	Power law size exponent
Batteries			
Energy related (cells)	$687,735/$MWh_e$	1 MWh_e	1.0
Plus power related	$0.39m/$MW_e$	1 MW_e	0.7
Pumped hydro energy storage			
Dams	$37,000/$MWh_e$	1200 MWh_e	0.7
Plus power related	$1.50m/$MW_e$	200 MW_e	0.7
Hydrogen			
Electrolyser	$1.09m/$MW_e$	20 MW_e	0.7
Plus underground storage	$655/$MWh_t$	20,000 MWh_t	0.7
Plus combined cycle gas turbine	$1.64m/$MW_e$	20 MW_e	0.7

Parameter values for inherently dispatchable technologies	Specific installed cost	Baseline capacity	Power law size exponent
Concentrating solar thermal			
Solar field	$0.46m/$MW_t$	600 MW_t	0.9
Plus storage system	$26,000/$MWh_t$	1429 MWh_t	0.8
Plus final conversion	$2.40m/$MW_e$	100 MW_e	0.7
Geothermal			
Hot sedimentary aquifer	$6.27m/$MW_e$	50 MW_e	0.7
Or engineered geothermal	$14.00 m/$MW_e$	50 MW_e	0.8
Bioenergy anaerobic digestion			
Digestor	$1.42m/$MW_t$	7.3 MW_t	0.7
Plus biogas storage	$12,391/$MWh_t$	11 MWh_t	0.8
Plus gas fired engine	$0.91m/$MW_e$	2.5 MW_e	0.7
Biomass combustion boiler			
Storage	$6.70/$MWh_t$	44,384 MWh_t	1
Plus boiler plus turbine	$4.89m/$MW_e$	15 MW_e	0.7

Note; subscript e indicates electrical and subscript t indicates thermal or fuel heating value.

The analysis has not attempted to quantify uncertainties or ranges in a rigorous manner, however it can be observed that some of the parameters have greater certainty than others. PV and wind values are based on a sufficient number of Australian projects to offer the greatest certainty, and the cost model should be able to predict 2017 costs to around +/- 10%. All other cost model predictions have an accuracy of around +/- 20%. Pumped hydro energy storage (PHES) is the most subject to project by project site dependant variation. Cost models for other technologies are challenged by a lack of completed Australian projects with known cost data.

Cost of dispatchable renewable electricity

The installed cost model has been used to examine dispatchable generation technology combinations. Particular systems were considered by; choosing a desired capacity of final output (for connection), choosing a duration of storage or generation (in hours at full capacity of output) and choosing an optimal level of energy collection to support the system with input energy needed.

In much of the previous published analysis that informs electricity policy, single LCOEs per technology have traditionally been used in a rather misleading manner to compare generation technologies that are variously continuous, peaking or variable. This study uses LCOE to compare dispatchable renewable options where the LCOE is presented as a function of the hours of stored energy (for solar or wind inputs) or the hours of delivery per day (for bioenergy or geothermal systems) that is achieved. LCOE calculations have been based on a weighted average cost of capital (WACC) of 6.5%/year.

The nominated storage or firm generation duration could be achieved with different ratios of input energy (collector capacity) to storage. For solar- and wind-based systems, the modelled ratio was determined by an optimisation process to find the lowest overall LCOE using a simple hourly dispatch model with NSW 2016 hourly solar and wind data for representative sites as appropriate. This optimal ratio was also used with the dispatch model to determine the annual generation (expressed as capacity factor) expected.

The dispatch model assumed there were no constraints on output, so that the full power output capacity is utilised whenever energy is available. The presence of storage serves to firm the dispatchable generation that is coincident with a solar or wind input and then further extend it after the input has dropped off. The optimisation means that different technology combinations will have different amounts of collector capacity for a given level of storage, so performance characteristics differ between technologies with the same notional number of storage hours.

Systems with small amounts of storage or duration of delivery are most applicable to the immediate smoothing and firming of wind or PV generation. Large amounts of storage or extended durations of delivery produce systems that run close to continuously in a manner analogous to traditional coal fired plants. Systems with storage hours or durations of operation of around four to eight hours are most applicable to meeting evening and morning peaks which coincide with the highest prices of energy in the wholesale market. When collection levels are adjusted to minimise the LCOE for any given level of storage, the results are as shown on page v. There are multiple options that can deliver a mix of firm and fully flexible electricity in a general least cost band between $90/MWh and $130/MWh at every timescale, with some niche options below $50/MWh. This overall least cost band corresponds to a ratio of between 1.5 to 2 times the cost of around $65/MWh that has been determined for VRE using these cost and financial parameters.

The overall message from this is that the various options for dispatchable renewable electricity each have times at which they are most cost effective, and these times overlap to a considerable degree. Given the uncertainties and range of variation with site and project, it would be generally incorrect to identify one technology as ‘best’ for a given timescale. Indeed, it can be said that in regard to dispatchable renewable electricity generation, Australia is ‘spoilt for choice’.

Results for particular technology combinations include:

Batteries with wind or PV

- Combining batteries with PV, wind or a grid VRE mix gives LCOE trends that start low and grow quite steeply with increasing amounts of storage. This is a consequence of a high cost per stored energy coefficient but a relatively low output power level related coefficient
- The lowest LCOEs of all battery options occur at a storage level of around half an hour. This illustrates that short duration batteries are particularly suitable to the smoothing of wind and PV electricity generation to reduce ramp rates in the case of sudden changes in resource levels. In comparison to other options, batteries remain in a competitive range out to about three hours of storage.
- The rooftop PV battery case has a higher LCOE than the utility-scale system, due to non optimal siting and fixed orientation plus not benefiting from the economies of scale that larger utility-scale systems do. However as systems are 'behind-the-meter' they are competitive with retail electricity.
- Battery system deployments have been on a trajectory of 40%/year compound growth and even if that slows to around 30%/year costs should continue to fall.
- The modular nature of battery cells means the cost penalty for small systems is less and, on the flip side, the cost benefit of very large systems is reduced over other technologies.

PHES with wind or PV

- PV, wind and VRE charged PHES offer a competitive and relatively constant LCOE across all durations of storage, it is particularly competitive beyond six hours of storage.
- PHES systems have been widely deployed around the world over many years. This means that the time to a future doubling of installed capacity and likely further cost reduction is much longer than other newer technologies.
- Overall LCOE from PHES with wind or PV charging will continue to drop as the cost of PV and wind electricity drops even if cost reduction in the PHES technology itself is small.
- Of all the dispatchable technology options PHES is the one that is most site specific and for which costs will vary from site to site, due to its dependence on geology and head height characteristics.

Concentrating solar thermal

- CST systems start to appear competitive from about six hours of installed storage and upwards. The higher LCOEs for short durations of storage reflect the relatively high installed cost of power related components, while the drop to lower values for longer durations reflects the low cost per stored energy of the molten salt system.
- There is a minimum in LCOE in the range of 15 to 20 hours of storage, however systems with less storage may be preferred to target generation in peak periods.
- CST with molten salt storage has only been applied commercially since 2006. Since then it has shown an average compound growth rate of deployment around 40%/year, although this is very dependent on the policy settings of the countries that have deployed it. Whilst this growth rate has slowed the likelihood of cost reduction remains high.

Hydrogen with wind or PV

- Hydrogen-based systems combined with wind or PV do not appear competitive over the zero to 40-hour timescale at current costs.
- Although hydrogen-based LCOEs are high, it is notable that hydrogen is the only technology option for which costs are still trending downward beyond 40 hours of storage.
- Hydrogen systems are now at a point in their commercial development where they are commercially available at scale, but it is too soon to draw any significant conclusions on the likely rate of deployment and cost reduction.
- As wind and solar electricity come down in cost, the impact of low efficiency of energy storage becomes increasingly less important. This will contribute to LCOE reduction irrespective of cost and performance improvements in the hydrogen technologies.
- Hydrogen has the lowest cost per MWh of storage capacity of any option other than biomass.
- There is potential to lower LCOE by making use of existing gas pipelines and gas turbine systems in hybrid mode.

Bioenergy

- Anaerobic digestion systems operating on zero cost waste and operating at 50% or more capacity factor are the cheapest dispatchable renewable generating option considered. Combustion-based bioenergy generation is also very competitive at 50% or more capacity factor, as long as low cost biomass inputs can be sourced.
- Biomass combustion systems typically store fuel in reserve for multiple days of operation. This is the cheapest form of stored energy available. Ensuring such systems can operate year-round as dispatchable power only requires extending the fuel storage to whatever time period is sought.
- The contribution of bioenergy to the generation mix is limited by the availability of waste or low cost feedstock. Future systems should be configured to run flexibly with reduced capacity factors to gain the greatest benefit.
- The bioenergy technologies analysed are mature, with modest growth in global deployment. Cost reduction potential for bioenergy options appears most likely to come from improvements in the harvesting, transport, and processing of biomass fuels.

Geothermal

- Australia does have some hot sedimentary aquifer resources. Power generation based on these appears to be cost effective and could be operated in a flexible manner to help balance VRE.
- Engineered geothermal systems were subject to high expectations in previous years. Based on cost estimates available, they do offer the potential of reasonably competitive dispatchable generation if operated continuously.

Testing the evolution of costs over time using an assumed 15% cost reduction on doubling of installed capacity for all technologies, but with appropriately estimated compound growth rates of installation, shows all costs coming down both for dispatchable renewable generation and VRE. On a timescale to 2030 there seems to be little shift in relativity between the technology combinations. With battery technologies having a faster assumed rate of growth than others, some convergence in cost of energy is seen for the six-hour storage case in particular.

Long-term energy reserve

A dispatchable renewable energy system that operates on a regular basis according to energy price signals in the market could have an additional 'long-term energy reserve' by providing additional storage that is kept fully charged for use in the event of a low input period or other contingency. The following table compares the marginal cost of increasing the level of storage for each storage option (not including the cost of energy collection or conversion).

Energy storage technology	Specific installed cost per equivalent stored electricity	Annualised cost of capital and O&M per equivalent stored electricity	Addition to LCOE at 1% utilisation
	$/MWhe	$/MWhe/year	$/MWhe
Biomass depot	$29	$3	$0.04
Hydrogen	$1,768	$276	$3
Hydroelectric dam	$46,250	$4,467	$51
Biogas accumulator	$36,444	$5,698	$65
Molten salt	$61,905	$5,979	$68
Batteries	$764,150	$94,260	$1,076

Storage of dry biomass in silos is extremely cost effective for this purpose, although considerable attention would need to be paid to managing storage conditions. Underground storage of hydrogen is the next cheapest option ($/MWh) as well as the cheapest that can be driven by wind, solar or grid electric input. However, the overall cost of dispatched energy from hydrogen-based systems is high. Batteries prove uncompetitive against other options for this type of long-term energy reserve, and this remains the case even with likely cost reductions over the next few decades.

The cost of the remaining options, PHES, molten salt for CST, and biogas are of equivalent orders of magnitude. These options can be considered as systems that would be operated in a 'firm and extend' manner on a day-to-day basis, in which the calculated LCOEs of between $90/MWh and $130/MWh would cover the collector and conversion systems plus the required level of storage to meet that type of operation. In an extended shortfall period of low sun and low wind the additional long-term energy reserve would be covered by an additional $60/MWh to $70/MWh, bringing the cost of the energy in those periods to around or below $200/MWh based on current estimated technology costs.

System services

The provision of various ancillary services and other system security functions is possible with dispatchable renewable generation options according to the characteristics of the final energy conversion subsystem.

The ramp time and characteristics of the various final energy conversions is summarised in the table below.

Final energy conversion technology	Very fast response possible synthetic inertia	Time to ramp from 0-100% output	Synchronous generator with inertia and fault current tolerance	Possible use as synchronous condenser
Inverter (for batteries or fuel cell)	Yes	100s milliseconds	No	No
Steam turbo generator (biomass or solar thermal)	No	30 mins for adapted fast start units	Yes	Yes
Gas turbine generator (hydrogen or biogas)	No	A few minutes	Yes	Yes
Gas engine (biogas)	No	A few minutes	Yes	No
Hydro turbo generator	No	A few minutes or seconds if running as synchronous condenser	Yes	Yes

If systems are primarily built to meet delivery of energy as needed, they can also provide ancillary services and system security benefits depending on how these are valued in the market.

In the context of a high share renewable energy system, the dispatchable generation taken up to meet energy demand when VRE is not available would also provide ample capability to provide ancillary services and system support.

Comparison with other options

Other options for providing similar benefits to dispatchable renewable generation include new gas-fired power generation, demand response measures and controlled curtailment of PV or wind.

The Finkel Review and other sources quote LCOEs for new build gas at around $145/MWh. This obviously depends on the future cost of gas and the capacity factor that plants are operated at. It would appear however that the dispatchable renewable generation options considered offer cost of energy very much comparable to this without the fuel and carbon price risks.

If electricity consumers are exposed directly to time of use price signals there will be some level of routine load shifting that would result at almost zero cost. Going beyond this the ARENA-AEMO initiative to procure emergency demand response capacity suggests that for anything up to ten four-hour events per year, this is cheaper than a dispatchable renewable generator only installed for such a purpose.

Given that this study finds the LCOE of dispatchable renewable generation is 1.5 to 2 times that of PV or wind generation on its own, it could be an economically rational approach to achieve a level of dispatchability by holding some wind or PV at up to 50% curtailment to allow up and down dispatchability for specified critical time periods. This would be comparable or complementary to adding short duration battery systems to PV or wind plants for firming, but it clearly cannot deliver strategically dispatchable generation.

Implications for the future

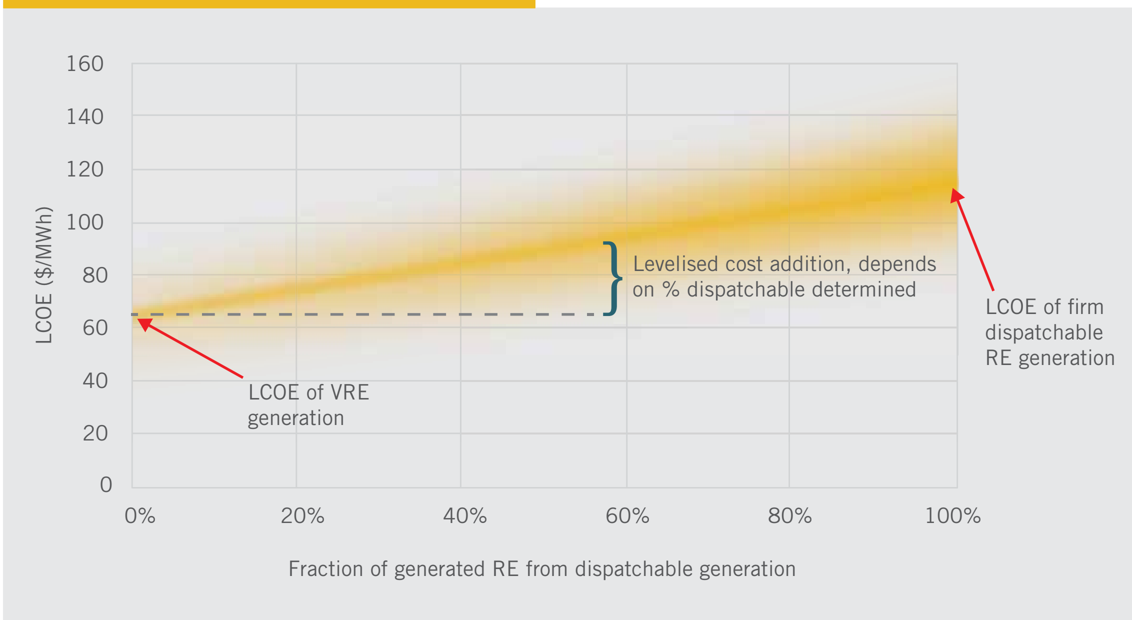
This study does not attempt to 'pick winners', but rather highlight the potential of available options.

Future detailed grid integration studies are needed to estimate the cost of an optimum mix of VRE, dispatchable renewable generation capacity and other measures. There is agreement that some level of dispatchable generation will remain essential. Increasing penetrations of VRE will mean that the average cost of electricity in the system will be lower than the cost of dispatchable renewable generation alone.

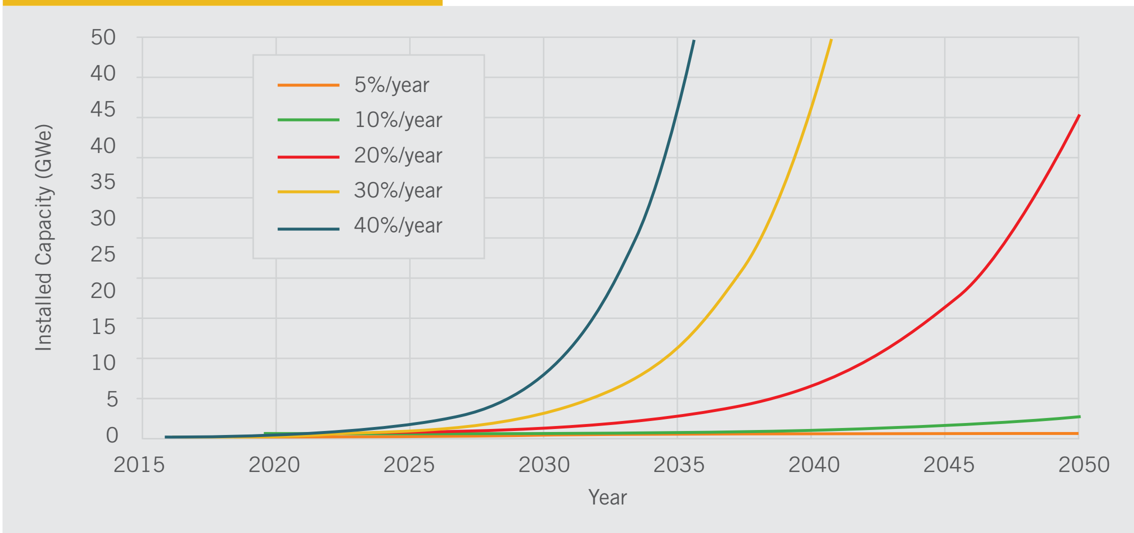
A mix of technologies, configurations and geographical locations is likely to minimise the overall cost through the smoothing effect of different generators delivering energy at different times and because different technology options are likely to be competitive for different market niches. The actual average cost of renewable generation for the system will be an average of LCOE of the dispatchable renewable energy and the unfirmed VRE that is adopted. For example, the addition of 30% of dispatchable renewable energy to a given capacity of VRE would take the average LCOE from $65/MWh to around $80MWh.

The chart shows the trend increase in LCOE as the fraction of renewables that are dispatchable increases. It does not consider the amount of dispatchable renewables that may be needed or the impact on final electricity prices.

AVERAGE COST OF RENEWABLE ELECTRICITY



COMPOUND GROWTH TRAJECTORIES

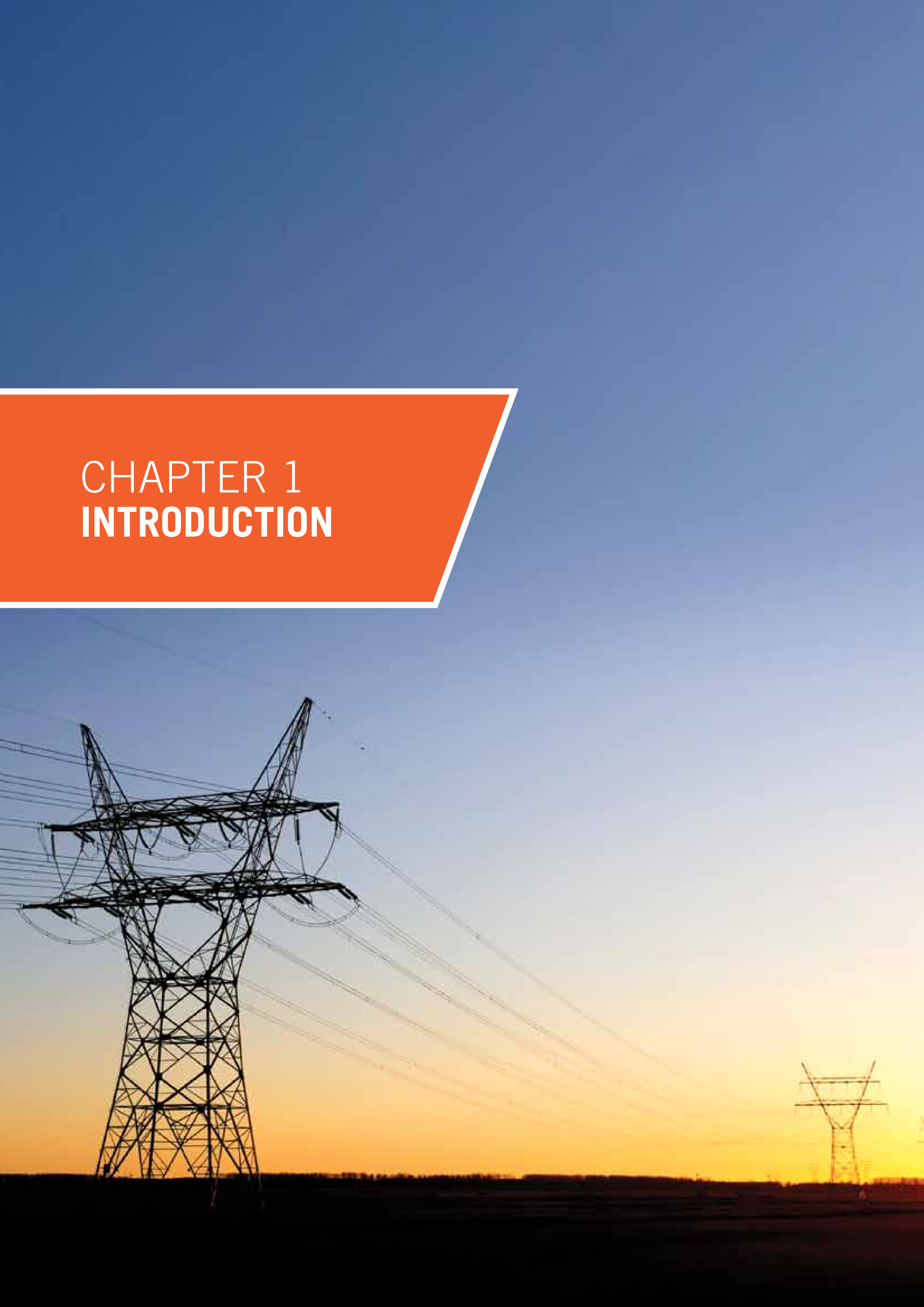


Over the past few years some key technologies like batteries and molten salt energy storage have shown deployment growth with a 40%/year compound growth rate. More mature technologies like bioenergy and PHES have global compound growth rates closer to 5%/year. For Australia moving forward, a compound growth rate in installed dispatchable generation capacity of around 25% per year (less than key technologies have achieved globally) would be easily achievable. This would progressively deliver increasing deployment that would provide comparable dispatchable capacity in advance of likely coal plant retirements[2] and so ensure an orderly transition to a future low or zero emissions electricity system.

To be reliable and secure a high penetration renewable power system will make use of a blend of dispatchable and variable renewable energy generation technologies. It is therefore important that energy policy is technology neutral and the services that are required to support system reliability and security are appropriately defined and valued.

2 Around 15GW$_e$ of coal plant retirement by 2040 is forecast.

CONTENTS



CHAPTER 1
INTRODUCTION

As Australia moves towards a low emission electricity system, there is a need to better understand the various technology combinations for dispatchable renewable electricity generation to support system reliability. This study identifies and compares the projected costs and performance of dispatchable renewable electricity combinations that are commercially available for Australia, or could become available in the near term. The storage options considered are assumed to be charged by co-located or separate variable renewable energy (VRE) generation, and therefore considered alongside renewable generation sources that are inherently dispatchable.

The Australian Renewable Energy Agency (ARENA) commissioned a team led by ITP Energised Group (ITP) working with the Institute of Sustainable Futures (ISF) and ITK Consulting (ITK) to undertake this study to inform the Agency's investment priority on delivering secure and reliable electricity. This document is supported by a cost model tool that is provided as a spreadsheet.

This study compares the cost of electricity from various dispatchable renewable technologies. It is important to understand that this cost is explicitly not the average cost of electricity of a 'system' or grid with 100% renewable energy. Instead the study is focussed on the individual cost of a 'dispatchable' engine such as pumped hydro, battery, or hydrogen, together with a dedicated renewable 'collector' such as a wind or solar farm, or an inherently dispatchable thermal turbine supplied by concentrating solar or bioenergy. The overall electricity cost for a balanced grid would therefore be the average cost of its total VRE sources plus the cost of its required level of firm dispatchable energy. Portfolio effects would almost certainly mean that the overall average cost of energy of a 100% renewable energy system would be less than the cost of individual dispatchable options. A portfolio of VRE has a lower variance than that of an individual VRE unit and therefore requires a smaller fraction of dispatchable energy for reliable operation.

This study also does not 'pick winners', rather it attempts to highlight the potential of available options.

While this study analyses specific technology combinations for dispatchable renewable generation, in practice future market signals will presumably elicit the required combination of generation, stored energy or other services in response to demand.

Future detailed grid integration studies are needed to estimate the optimum mix of VRE and dispatchable generation capacity. A mix of technologies, configurations and geographical locations is likely to minimise the overall cost due to the smoothing effect of the different VRE generators delivering energy at different times.

This study has been prepared with several audiences in mind:

- For ARENA, this study should increase understanding of the relative economics and performance of the technologies it has already been supporting and help to inform future investment decisions.
- For forecasters and modellers, this study seeks to provide high quality input on the costs and performance of the key technologies, together with an understanding of cost dependencies that should assist in providing a reality check on the results of grid integration modelling. The accompanying technology cost model can be used to develop cost estimates for different technology configurations, as an input to further modelling work. The analysis of relative performance at different storage volumes can be used to help choose a representative suite of potentially competitive options for various market niches.
- For policy makers, this study should provide an understanding of the capabilities and cost sensitivities of key technologies and concepts at a time when electricity system reliability is receiving considerable attention. Further, it will support understanding that different technologies could be competitive depending on the services the market requires and that the most efficient outcome (which regulatory/market frameworks should aim to deliver) is likely to be a combination of those technologies, reflecting the combination of services needed.
- For project investors, this study does not provide methods to allow project specific configurations to be chosen, rather it seeks to contribute to a broader understanding of the context and competing approaches that can inform their specific optimisations.

1.1. Need for study

Australia's approach to its future emissions reductions and the operation of its energy system is currently receiving considerable attention. The country has a commitment to specific GHG reduction goals by 2030 and an overall commitment to the COP 21 goals of limiting global warming below 2ºC. This in turn leads to the implicit conclusion that net zero emissions are required from the electricity sector by around 2050.

Figure 1 illustrates the nature of the transition in the power supply mix required to achieve zero emissions. In Australia, prior to the addition of VRE generation to power systems, power supply to meet demand came from large-scale, inflexible fossil fuel generation (coal) with more flexible fossil generation (gas) or large hydro as intermediate and peaking generation.

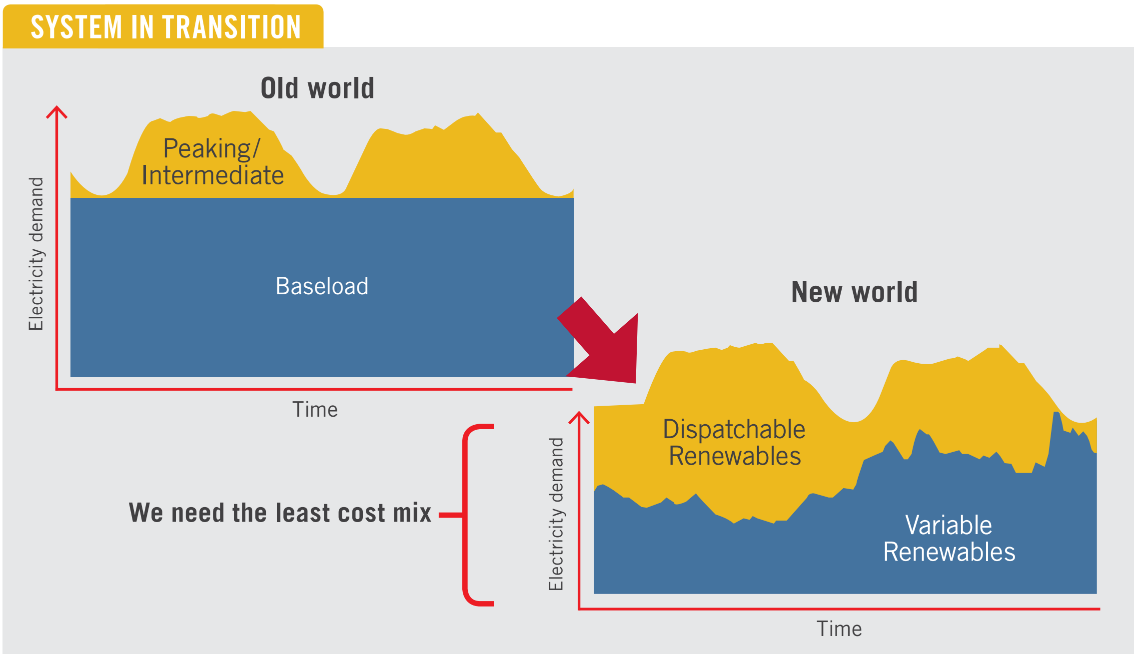


Figure 1: Electricity system in transition

As the power system evolves with higher levels of VRE generation, electricity must be delivered from a greater range of sources with faster rates of change in output to complement the behaviour of VRE generation sources. A modern, low emissions electricity system 'in the new world' should, in a least-cost manner, constantly balance demand and supply while also managing stability using ancillary services such as frequency and voltage control.

The VRE options of wind and photovoltaics (PV) are increasingly being recognised as the lowest cost per unit of energy produced. However by their nature they are variable and cannot sustain the electrical system alone. In an ideal least-cost generation mix, as the costs of renewable generation and energy storage fall, a portfolio of technologies should emerge according to available resources and electricity demand in the geographical areas of application.

Further to this, the achievement of a long-term, least-cost mix involving new technologies suggests the need for a planned transition that phases in the new and phases out the old in an optimal manner. This is unlikely to be the same as seeking lowest costs at any given stage.

Planning the transition would benefit from a better understanding of the costs and performance of dispatchable generation, however a review of the existing literature (see Appendix A) shows that few studies have looked at these costs in a consistent and like for like manner. Some (Lazard, 2016; IRENA, 2017; Jay Rutovitz *et al.*, 2017) focus on the costs of storage alone, while others (Australian Energy Market Operator (AEMO), 2013; AGL Energy; WorleyParsons Services; ElectraNet, 2015; Blakers, Lu and Stocks, 2017) focus on the average cost of energy for a 100% renewable grid study.

This study's approach to examining generation and storage technology combinations builds upon the many previous studies that have examined various technologies independently on a cost of generation or cost of storage basis (for example, Crawford *et al.*, 2012; Bureau of Resources and

Energy Economics, 2013; Brinsmead, T.S.; Graham, P.; Hayward, J., Ratnam, E.L., Reedman, 2016; Lazard, 2016).

The outcomes of this study are also relevant to the design of policy mechanisms for dispatchable capacity and reserve procurement that are being considered following on from the Finkel Review (Finkel *et al.*, 2017).

1.2. Technologies considered

This study examines electricity generation and storage technologies that together can offer dispatchable behaviour, and could have a role in high penetration renewable electricity systems (up to and including 100% renewable systems). This includes combining VRE generation with different storage and control approaches, renewable energy technologies that possess inherently dispatchable electricity generation characteristics, and management of load to optimise the use of renewable energy and storage options.

This analysis examines technology options by general class rather than comparing product variations within a class. Thus, for example, large network-connected batteries and behind-the-meter batteries are considered, but the differences between alternative battery chemistries are not considered. The analysis is limited to commercially available and emerging[3] technologies that could in principle be constructed immediately at utility scale (hundreds of MW). The presence of emerging technologies in a technology class is taken as an indication there is a path to future cost reductions. The technology combinations analysed are:

- utility-scale wind or solar PV generation or a grid-sourced mix of renewable electricity in combination with:
    - large network-connected batteries, with lithium-ion batteries considered as the representative
    - pumped hydro energy storage
    - hydrogen storage (electrolysers plus underground storage followed by thermal generation)
- behind-the-meter solar PV generation and batteries
- concentrating solar thermal (CST) with molten salt thermal storage
- bioenergy via either:
    - anaerobic digestion combined with gas engine power generation
    - combustion boilers burning woody biomass with steam turbines
- geothermal generation, via either:
    - hot sedimentary aquifers
    - engineered geothermal systems.

[3] Emerging here is interpreted as newly commercialised, not those still in the laboratory.

1.3. Methodology

The methodology used for this study was to:

Develop dispatchability value and service options: These have been matched to the capabilities of the various technology options available.

Collect key cost and performance data: This includes capital costs as a function of both power and energy storage capacity and other key performance parameters including efficiencies and degradation rates, lifetimes and operating costs.

Consult with stakeholders: Bilateral teleconferences and face to face meetings have been held with key stakeholder groups including sources of key technology information, policy makers and government agencies, and parties undertaking relevant ongoing studies.

Determine plausible ranges for cost reduction projections into the future: A standard learning curve approach to cost reduction has been assumed. This is combined with a likely range of deployment growth to give estimated maximum and minimum trajectories of cost reduction over time for each technology.

Develop and analyse cost of establishment and cost of energy: The cost of establishing and maintaining a dispatchable renewable energy system was investigated, along with the levelised cost of delivering energy from the system. The sensitivity to configuration was also examined, particularly the dependence on the duration of possible full rated energy delivery.

Consider costs against value and revenue generation potential: This included various approaches to price arbitrage and targeting high value energy sales as well as sources of value from other services, and a comparison with other non-renewable generation and actions such as demand response and managed VRE curtailment.

Consider policy and regulatory implications of modelled outcomes: This included interaction with regulatory frameworks for generation, distribution and retail markets.

1.4. Structure of report

The remainder of this report is structured as follows:

Chapter 2. Dispatchable energy services and definitions: Provides a definition of dispatchability and other terms and discusses the nature of services provided by dispatchable sources.

Chapter 3. Establishing initial cost: References Appendix A for detailed background on the technology building blocks and discusses the approach to installed cost models, combining the building blocks, growth rates and learning and cost model results.

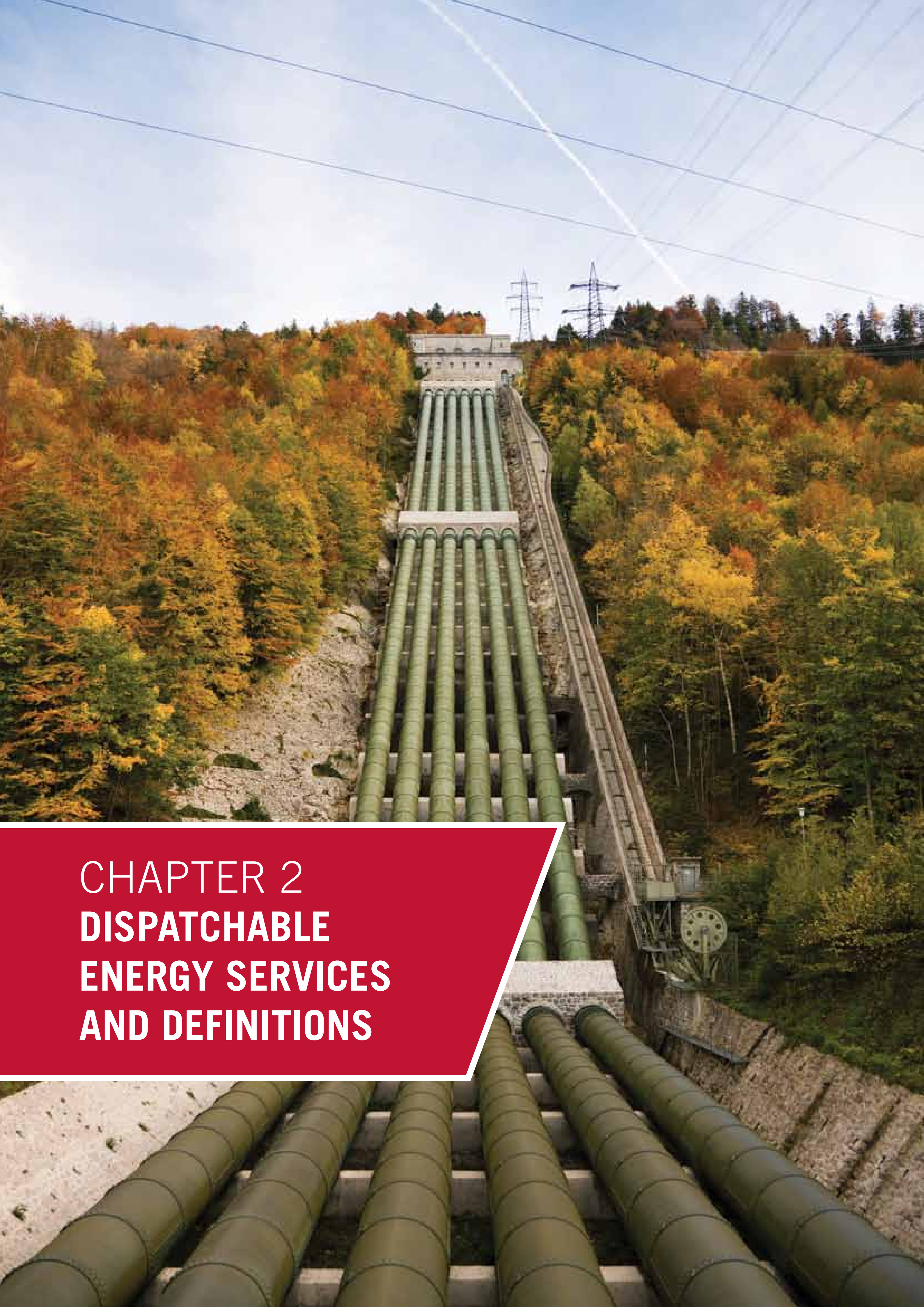
Chapter 4. Developing dispatchable combinations: Considers how a dispatchable renewable generating combination interacts with the electricity system, presents technology specific results for the levelised cost of firm energy and considers the economics of other services and the comparison to other options.

Chapter 5. Implications for the future generation mix: Summarises the technical outcomes, discusses the likely evolution of the generation mix and draws lessons for the Australian market and policy settings.

Chapter 6. Conclusions

Glossary: Contains and extended explanation of key terms that relate to the area of dispatchable generation

Appendices: Provides detailed technical background in various relevant areas



CHAPTER 2
DISPATCHABLE ENERGY SERVICES AND DEFINITIONS

There are many useful services that a dispatchable energy system can provide. For this study, those services are considered to be:

- sending out electricity when most needed, including:
    - short-term smoothing of wind and PV
    - longer-term firming and extending generation from wind and solar
    - targeting peak demand periods
    - providing a long-term reserve for periods with little sun or wind
- supporting system security (inertia, fault current)
- providing ancillary services (frequency, blackstart etc.)
- supporting transmission and distribution networks.

Although much of the current public debate is around issues of system security, the evidence suggests this is relatively easy to address and only becomes a problem when neglected (Jay Rutovitz *et al.*, 2017). The emphasis of this study therefore is on the provision of electricity when it is most needed, which appears to require the greatest long-term planning and investment. It is also likely that the ability to ensure system security and provide ancillary services would follow inherently if the timely delivery of energy is properly addressed using the technology options investigated.

2.1. Defining dispatchable generation

In the current energy debate the concept of 'dispatchable' electricity generation has become very topical. Simply defined, a dispatchable generator can raise or lower its power output in response to a command from the electricity system operator. Within this broad definition, dispatchable generation systems can have differing characteristics including:

- response time
- availability to generate
- duration of generation
- practical upper and lower limits on generation level
- ramp rate from one generation level to another.

It is also important to consider a number of related concepts due to their overlap and resulting confusion with 'dispatchability':

> **Flexible generation** is a subset of dispatchable generation, with a more agile ability to ramp up or down, or on or off, that must reliably be available at times of need to facilitate rapid load following or rapid balancing of variable renewable generation. Generation that is both flexible and dispatchable is likely to be required to complement high penetrations of variable renewable energy, as noted by AEMO (AEMO, 2017).

> **Firm generation** is a constant level of output that a generator legally or commercially commits (or warrants) to deliver at a specific power level for a certain period of time. Thus, a dispatchable generator would offer firm output when it is 'dispatched' by the system operator. This does not preclude the possibility of a breakdown, but it implies the generator's confidence in having the necessary energy available to fulfil the obligation for that period.

In addition to this, the Glossary at the end of this report, explains the meaning of numerous other concepts that are relevant to the consideration of dispatachble generation.

2.2. Sending out electricity when most needed

In considering the dispatchable renewable electricity generation systems listed in Section 1.2, there is a distinction between those that take their primary energy from a variable input such as wind or sun, and those that involve an essentially constant rate of primary energy input such as bioenergy or geothermal. Hydro power can demonstrate either characteristic, with run-of-river systems and small reservoirs having a close dependency on variable rainfall, while large reservoirs can be available constantly for an extended period and pumped hydro energy storage (PHES) does not necessarily require a continuous supply of water.

Figure 2 illustrates the effect of combining a variable input (case a) with some form of energy storage to achieve dispatchable generation. In case b) a modest amount of storage allows energy from a variable resource to be sent out in a firm and dispatchable manner throughout the main collection time(s), when the input is available. The level of output can be guaranteed for one or more dispatch or trading intervals. If more storage is available as shown in c), the result is a firm and dispatchable system that can extend or even shift its delivery of energy for some time after the variable input has fallen off. In the interpretation of d), the addition of the extra storage can be viewed in another way; when the variable resource is available the store may become fully charged. At that point electricity must be sent out or the energy will be lost. This 'use or lose' (UOL) energy is nonetheless fully firm and dispatchable as in cases b) and c). However, when the resource input drops off, energy that has been accumulated is available for dispatch in a much more strategic manner. This energy is not only firm and dispatchable but also can be used in a 'strategically higher value' manner, according to price and demand signals, as it can be sent out when desired.

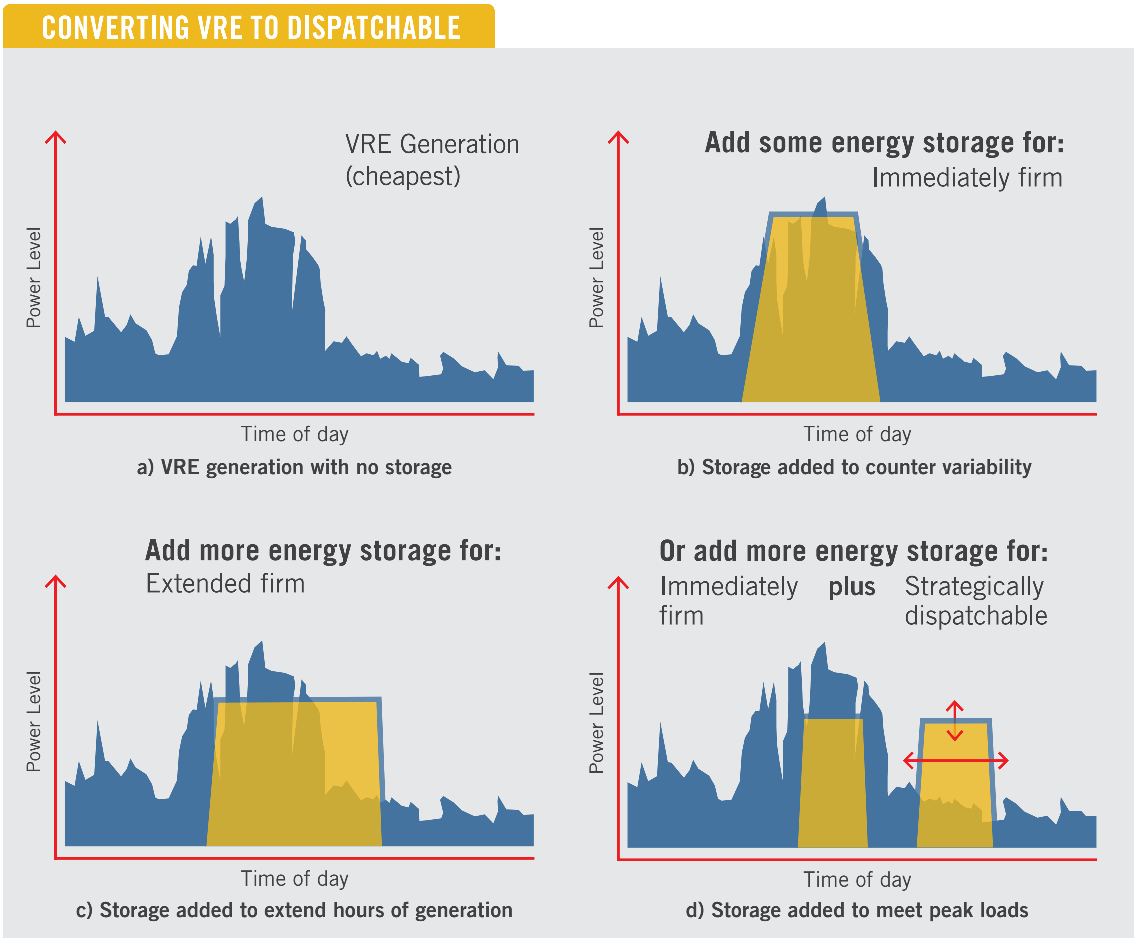


Figure 2: Variable generation with different storage options added

For a renewable electricity system with a primary energy source that is essentially constant, such as an anaerobic digester plus gas engine, the situation is as illustrated in Figure 3. A continuous resource would allow continuous generation, matching the commonly used concept of a baseload generator. This would be dispatchable but not necessarily flexible. If the system is reconfigured with buffer storage as needed, so that it is deliberately operated for reduced and targeted time periods instead, its behaviour becomes strategically high value.

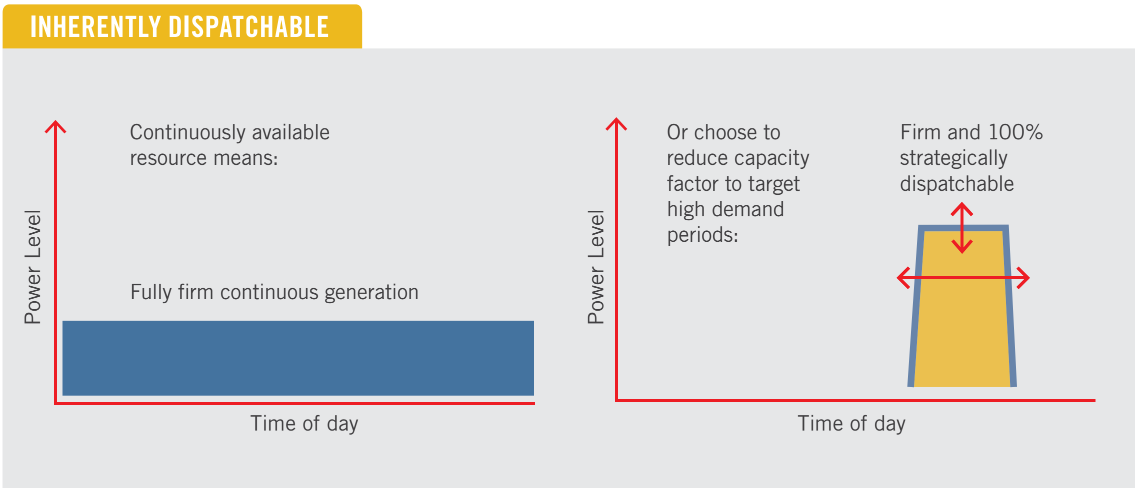


Figure 3: Dispatchable generation from a continuously available resource

Peak demand periods and load following can be targeted by suitably firming and extending wind or solar inputs or by using inherently strategic dispatchable generation in combination with variable renewable energy. There may be an additional need to meet electricity demand during periods involving multiple days of low wind and solar resource availability, which suggests the concept of a long-term renewable energy reserve that is used infrequently for such events. If dispatchable renewable generation systems are configured for routine regular operation, the possibility of increasing the size of the energy store with an additional amount that is contracted to be held back from regular operation arises. This overlaps with the currently discussed concept of strategic reserve generation, which is a reserve of power capacity that is implicitly dispatchable and can be called on when infrequent cases of very high demand are likely to exceed otherwise available levels of generation. Although overall power generation capacity would not be increased, adding a long-term energy store to a dispatchable renewable generator would allow that generator to be available at times when it otherwise could not be, thereby reducing the additional requirement of a strategic capacity reserve.

2.3. Other services

The provision of inherent system support and ancillary services is largely a feature of the final generation stage in the system that sends out the electricity. Figure 4 shows the services required, and the relationship between them.

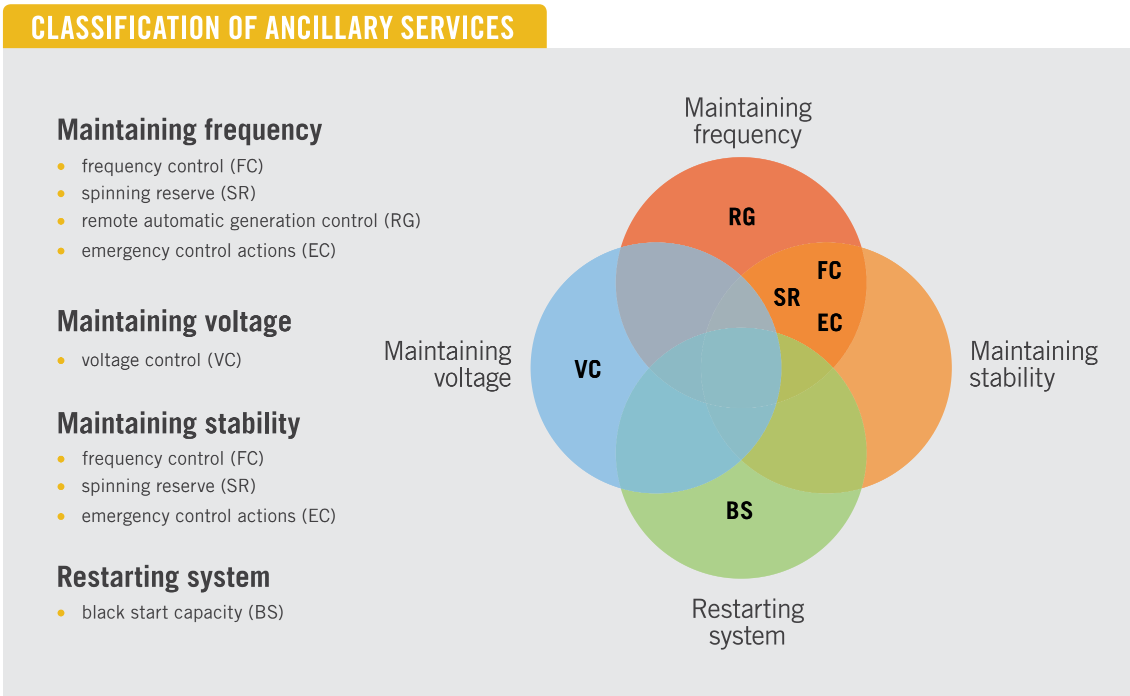


Figure 4: Classification of ancillary services needed and supplied adapted from (Elsen *et al.*, 2004)

In the NEM, some services are procured in a competitive market, some are procured by tender processes and some are simply taken for granted as inherent features of existing generator types. Appendix C, discusses the types and classifications employed in detail.

CHAPTER 3
ESTABLISHING INITIAL COST

3.1. Approach to cost models

This study has sought to develop models for installed costs of the various combinations of technologies which, while being simple, are sufficiently flexible to offer insights into the options for configuration and use. The models include information on:

- size of system
- configuration for duration of delivery
- year of construction.

The various technology options can be treated as a combination of subsystems, as illustrated in Figure 5, that have been categorised as:

- energy collection (e.g. PV array or wind farm, heliostat field, biomass resource etc.)
- initial energy conversion (e.g. electrolyser or power conditioning prior to storage)
- energy storage (e.g. battery cell, molten salt tank, dam etc.)
- final energy conversion (e.g. boilers and turbine, inverters and power conditioning etc.).

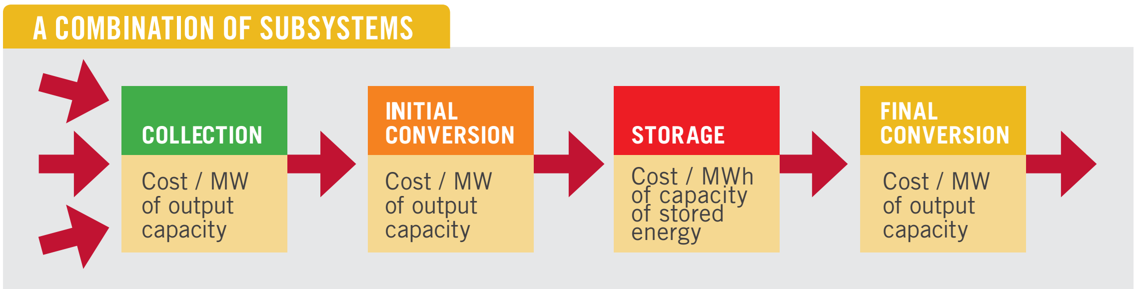


Figure 5: Component subsystems of modelled dispatchable renewable energy generation systems

The study hypothesis is that the installed cost of energy collection elements can be modelled with a simple function linked to the power capacity (MW) of the collection system, the pure storage elements modelled with a simple function linked to the storage capacity involved (MWh), and the energy conversion aspects modelled as a function of the power capacity (MW) of the final output. In each case the cost is linked to the energy output units of the subsystem in question, not the electricity output of the total system.

3.1.1. Size dependence

There is a strong established body of evidence that empirically demonstrates large technology items have a cost dependence on size that can be expressed as a power law (Perry and Green, 1999). That is:

$$Cost(capacity\ x) = Cost(capacity\ y)\left[\frac{x}{y}\right]^n$$

Where: *x* = plant capacity of interest

y= base case plant capacity

n = exponent less than 1

This means that if the size of an item is doubled, the cost will be less than doubled. In many cases an exponent close to 0.7 is found, which is anecdotally referred to as the 'seven tenths' law or more generally 'economies of scale'. Where an item has a strong element of repetition in equal cost modules, then an exponent of one would apply, that is cost is simply proportional to size. In some cases, the cost information analysed in this project has confirmed the power law cost model is appropriate. In others, where data has provided limited information, an exponent between 1 and 0.7 has been chosen based on an understanding of the technology in question. Technology stakeholders have also been consulted on this matter.

3.1.2. Growth rates and learning

Typically, new technologies that are adopted on a large scale show historical development paths that combine a sustained period of compound growth in levels of adoption with a learning curve approach to cost reduction that is correlated with the level of capacity installed. Wind power and PV have been doing just this for the past three decades and are continuing to do so in a highly visible manner.

It is common practice to examine the track record of a technology using the idea of a 'progress ratio'. This is the multiple by which the cost changes each time the total installed capacity is doubled. A constant progress ratio (PR) is equivalent to an exponential decay to zero cost (and hence only a good approximation to behaviour in the early stages). In other words, a progress ratio of 85% for example, would mean that cost decreases by 15% every time the installed capacity is doubled. Expressed mathematically:

$$Cost = C_0 \times PR^{(\log_2(Q/Q_0))}$$

Where:

C_0 is the initial cost per unit and $(\log_2(Q/Q_0))$ is the number of doublings in capacity to achieve a capacity Q from a starting point of Q_0.

It is difficult to determine the progress ratio that a technology is likely to benefit from in coming years, however precedents from other fields are a reasonable indicator. The World Bank (World Bank, 2006) identified a relevant study by the International Energy Agency (2000) that analysed the progress ratios of a large variety of products from the electronics, mechanical engineering, paper, steel, aviation, and automotive sectors (see Figure 6).

The identified progress ratios are widely spread, with an apparent median value of approximately 0.85. The message to be taken from this IEA study is that significant cost reduction is a virtual certainty if a technology is adopted in a serious way, with a progress ratio of 0.95 essentially the 'worst case' outcome.

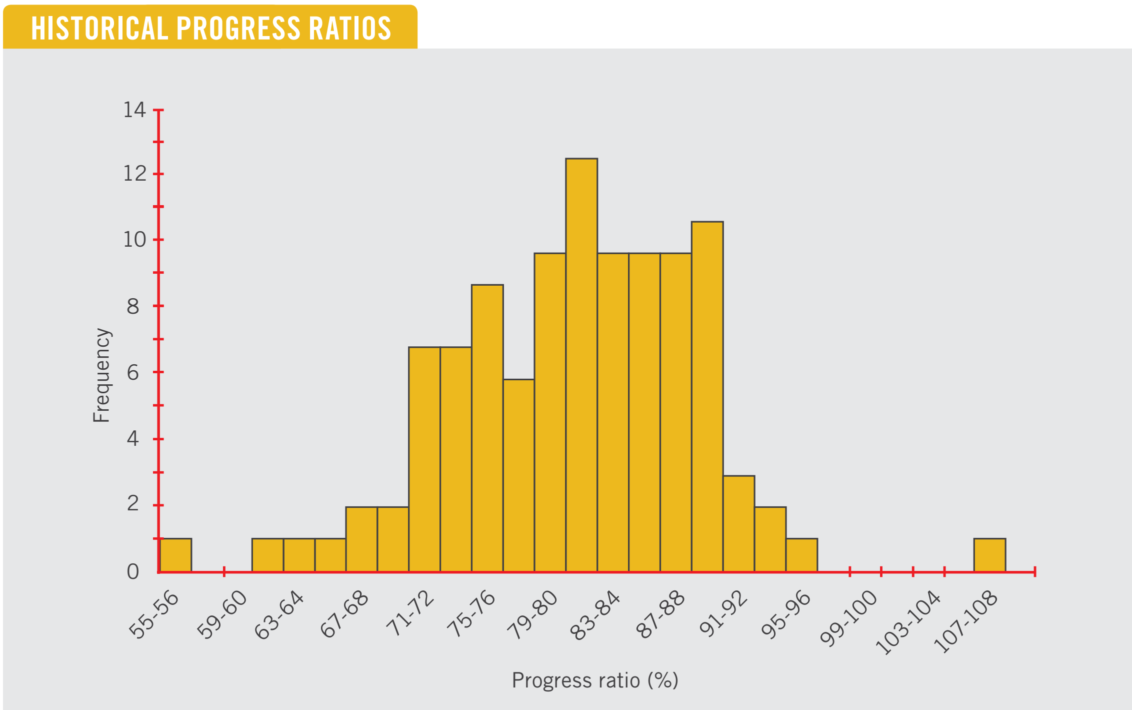


Figure 6: Historical progress ratios for a variety of technologies including "manufacturing processes in industries such as electronics, machine tools, system components for electronic data processing, papermaking, aircraft, steel, apparel, and automobiles" (International Energy Agency, 2000)

However, extrapolation from a learning curve cannot predict the ultimate limiting cost in a meaningful way. Ultimately a close to limiting cost value will be reached when it is linked to the fundamental material and energy inputs of a technology. Brinsmead et al. (Brinsmead, T.S.; Graham, P.; Hayward, J., Ratnam, E.L., Reedman, 2016) discuss a CSIRO model for cost reduction behaviour that attributes different learning rates according to the level of maturity of a technology, as illustrated in Figure 7. They also note there are both local and global learning effects that can occur at different times if a country begins to deploy a technology later than the main uptake of global deployment.

Brinsmead et al. suggest a 9% cost reduction on doubling for lithium-ion battery technology, 10% cost reduction on doubling for inverters and 15% for less mature technology items.

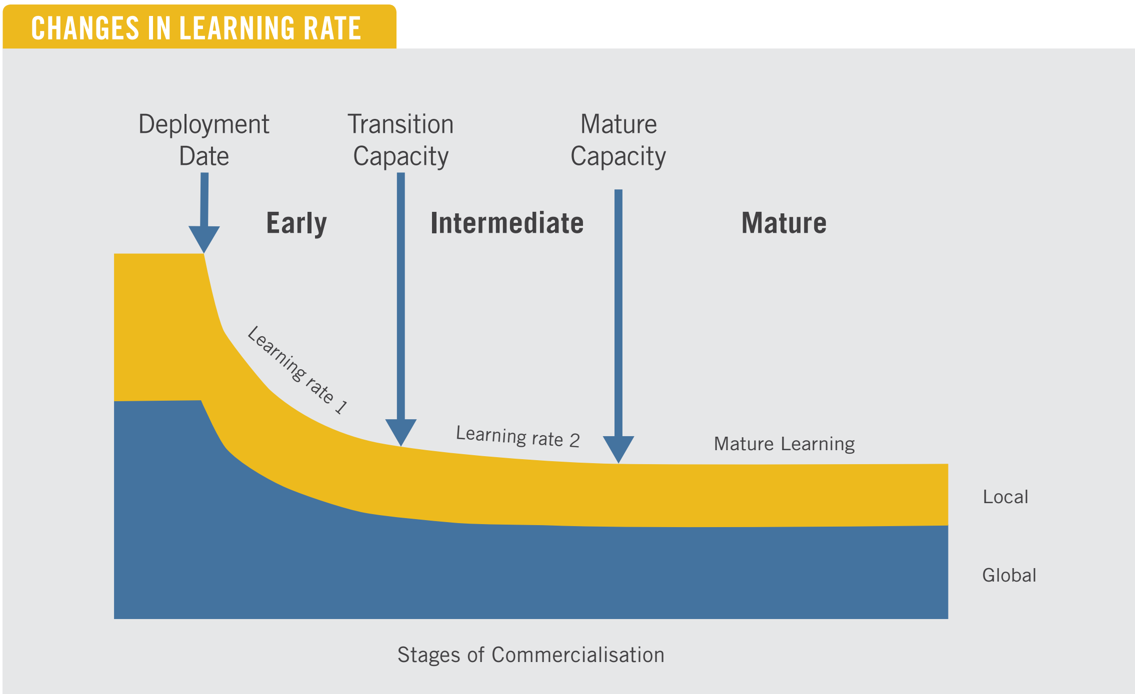


Figure 7: Illustrating changes in learning rate as a technology progresses through stages of commercialisation (reproduced from (Brinsmead, T.S.; Graham, P.; Hayward, J., Ratnam, E.L., Reedman, 2016)*)*

PV modules have shown a learning rate of 20%, although this may now reduce as the technology matures. This study has used a 15% rate for all technologies, noting that this may be high for some and low for others. More critical to the actual cost trajectory will be the market uptake and hence the time taken to double technology production or installation. This is difficult to gauge because it is dependent on worldwide policy and other drivers.

A further consideration is that the learning curve model could be applied to either installed power capacity or stored energy capacity, or the separate subsystems independently. To a large extent these will be expected to correlate closely but not be identical. This study has dealt with subsystems separately and with differing levels of deployment growth between them. It also makes the somewhat arbitrary assumption that O&M costs for a subsystem always remain in proportion to installed cost.

With progress ratios falling in a narrow band, the time to deployment doubling can be the major factor in determining the overall trajectory of cost with time.

The US Department of Energy's energy storage database (Sandia, 2016) provides very useful data on overall installed capacity and the growth rates of various technologies. Figure 8, Figure 9 and Figure 10 illustrate the historical deployment trends for concentrated solar power (CSP), pumped hydro and batteries, together with the associated compound annual growth rate (CAGR) fits.

MOLTEN SALT CSP

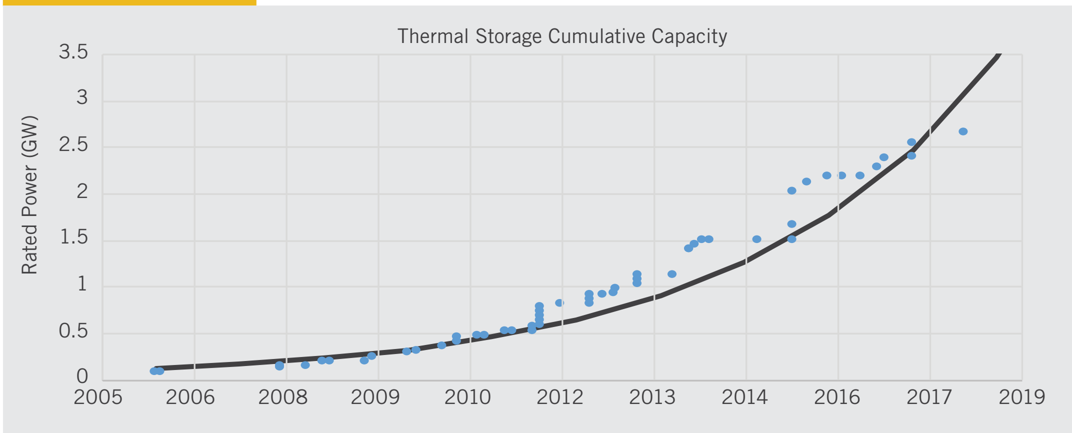


Figure 8: Molten salt CSP compared to a 41 %/year CAGR

PUMPED HYDRO

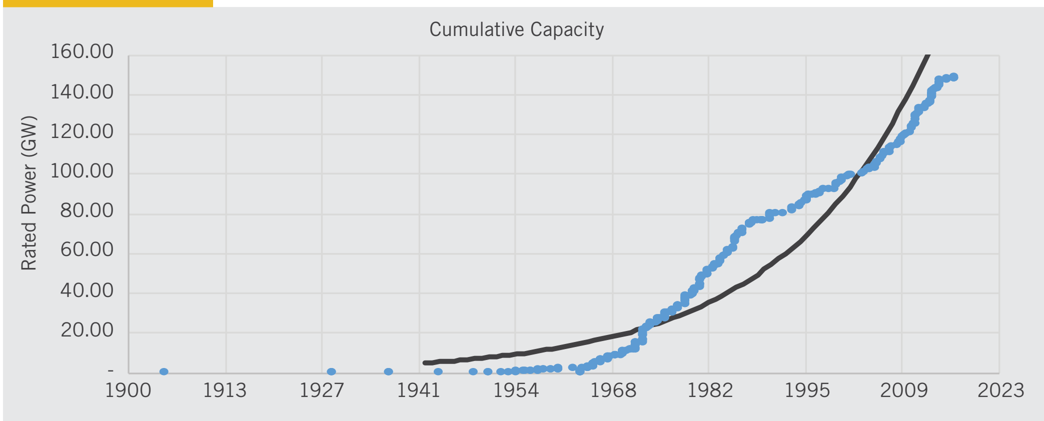


Figure 9: Pumped hydro compared to a 5 %/year CAGR

BATTERIES

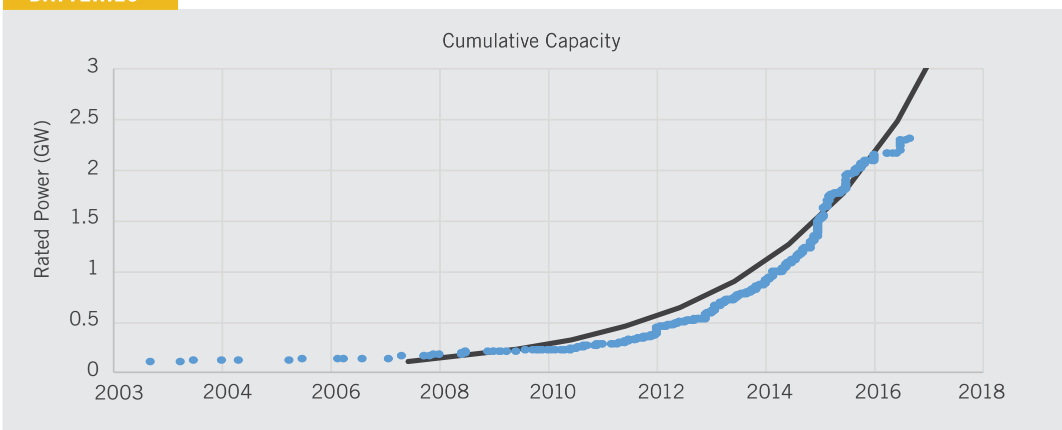


Figure 10: Batteries compared to a 40 %/year CAGR

The typical progression for a technology is best characterised by an S curve, that is initial exponential growth that transitions to an asymptotic approach to a final mature market share. Bumps and pauses are typically encountered as market and policy measures intervene in a discontinuous fashion. However, it is difficult to determine at the time whether the slowing of a particular technology's progression is such a bump or if it is the beginning of a transition to the mature technology deployment level.

PHES has the largest installed capacity of any recorded energy storage technology. It is apparent from the deployment graph though that PHES is also a mature technology dating back to the middle of last century. Global deployment rates at present are best modelled as linear growth, while a compound growth curve of 5%/ year can also plausibly be fitted.

Battery storage growth however shows a much stronger compound growth characteristic, and is well modelled by a compound annual growth curve of 40%/year.

Thermal storage, representing those CST power plants with thermal storage, is well fitted by a compound annual growth curve of 41%/year. This data is a subset of CST growth overall.

Figure 11 illustrates the relative cost reduction that would be achieved for deployment growth rates between 5% and 40% per year for any technology with a 15% cost reduction per doubling. Clearly global growth rates up to 40%/year can be achieved at times. In such a case, cost could halve by 2025. On the other hand, a 5%/year rate would see only a 30% drop by 2050.

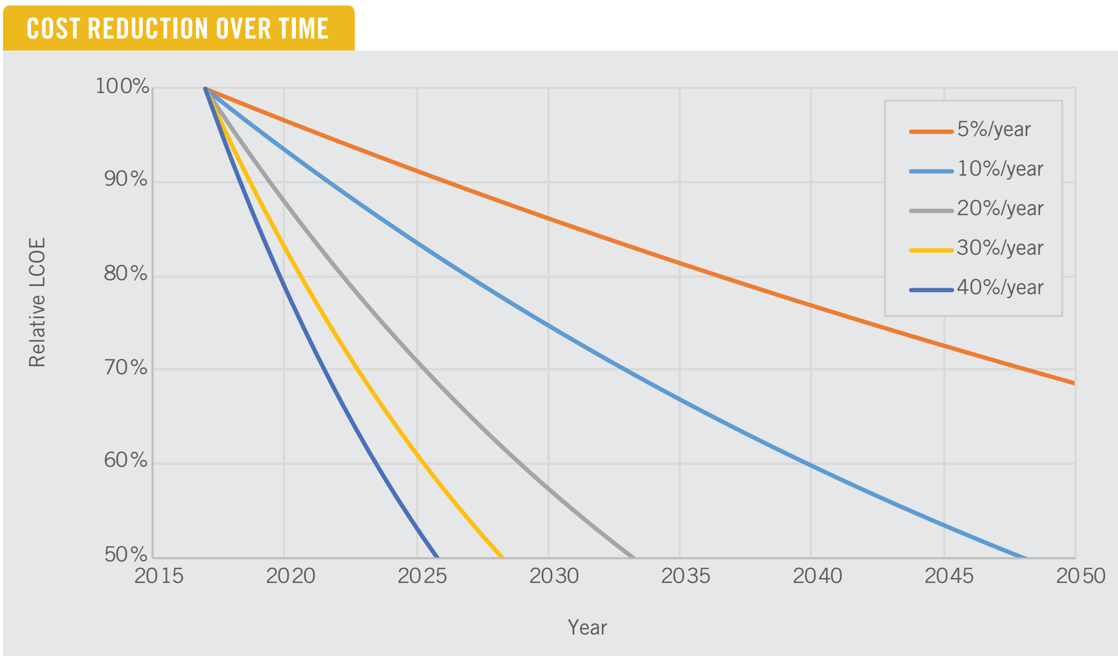


Figure 11: Impact on LCOE of different compound annual growth rates for a 15% cost reduction on doubling of installed capacity, for any given technology

In summary, historical experience shows that the adoption and growth in deployment of a technology is the main driver for its cost reduction.

3.2. Cost model results

The installed cost data presented in this report is the best available results identified by the study that are valid for Australia to the end of 2017. Costs include indirect costs and connection, but exclude any possible extensions to the electricity network. They also exclude any cost penalties that may apply to first of a kind projects for any particular technology.

Data has been sourced from international and Australian published material, as well as discussions with relevant stakeholders, which in some cases were commercial-in-confidence. In each case an overall installed cost together with the relevant subsystem sizes were used as the input data. Weighting was applied based on the considered relevance and accuracy of each source of data, with more recent and Australian specific data weighted higher. The installed costs from each data source were compared with the predicted costs from the models described in Section 3.1, where the relevant size inputs were used and the model parameters were varied to achieve a 'minimum least squares' fit to all data for each technology.

In some cases there was sufficient accurate data to achieve a fit to both the cost multiplier and the size exponent. In other cases this was not possible and the value of the exponent was hypothesised by analogy with other technologies and only the cost multiplier was determined by the fitting process.

The following sections present the sources of cost data and results for each of the dispatchable technologies considered in this study.

3.2.1. Photovoltaics

PV is one of the faster growing renewable energy technologies, both in Australia and worldwide. Given it is a modular product, deployment can range from several watts in small electronic appliances, through kWs in small-scale off-grid and residential grid-connected systems, to full-scale power plants measured in hundreds of MW. As the volume production of PV has grown, its costs have fallen rapidly, thus increasing uptake further. Manufacturing capacity continues to be expanded and efficiencies increased. In 2017, an estimated 100 GW of PV was installed worldwide, with over 1.2 GW in Australia.

To establish an installed cost model for large-scale PV systems, the costs of systems established under the ARENA large-scale solar (LSS) round have been compared, along with more recent projects for which publicly available total project costs are available. The installed costs of more recent projects are lower per installed capacity however it is found that this in fact correlates very well with the trend to increased system size.

Further technical and market details as well as costs are provided in Appendix B.1.1.

The model cost parameters adopted for this study are shown in Table 1. The data for utility-scale PV provided a very accurate fit, making it possible to determine both the multiplier and the size dependency exponent. The exponent value of 0.89, being close to 1, indicates that PV fields are quite modular in nature, with the presence of the inverter system and other effects providing some economy of scale.

Table 1: PV costing model

	Specific installed cost	Baseline capacity	Capture capacity factor	Power law size exponent	Life-time	Fixed O&M cost	Deployment growth
	m$/MW	**MW**			**year**	**%/yr**	**%/yr**
PV utility-scale	$1.87	100	28%	0.89	30	1%	30%
Rooftop PV	$2.00	0.01	17%	1	25	2%	30%

Note: costs expressed per MW ac connected rather than dc of the field.

3.2.2. Wind

After established hydroelectric systems, wind power is the largest source of renewable electricity generation in the world as well as Australia. Wind is a mature technology and historically has been the lowest cost form of non-hydro renewable electricity generation at large scale. As a result, wind power has fulfilled most of the capacity additions under Australia's Renewable Energy Target (RET) to date.

The wind industry has standardised its systems using turbines that involve a horizontal axis with three blades. Trends have been to progressively increase the size of these systems, with units now available at close to 10 MW. There has also been a trend towards using variable speed systems that rely on power electronics to transform power back to 50 hertz AC, meaning the turbines are not synchronous generators.

Appendix B.1.2 provides more technical background on wind technology as well as its deployment status and costs.

The wind power cost parameters determined for this study are given in Table 2. The power law exponent for size dependence was postulated at 0.9 (assuming a similar level of modularity as a solar PV field) as the data was not sufficient to determine this statistically.

Table 2: Wind farm cost model parameters after fitting

	Specific Installed cost	Baseline capacity	Capture capacity factor	Power law size exponent	Life-time	Fixed O&M cost	Deployment growth
	m$/MW	**MW**			**year**	**%/yr**	**%/yr**
Wind	$2.18	100	38%	0.9	30	2%	10%

3.2.3. Batteries

Batteries store electricity in electrochemical cells, which are organised into packs to achieve the required energy storage and power capacity, and combined with a power conversion system to connect with the AC grid. A wide range of cell chemistries are available and battery technologies are under continuous development.

Lithium-ion technologies are presently growing the most rapidly compared to other chemistries. This is due to their high-energy density and long-time development in the consumer electronics industry, as well as their increasing use in the electric vehicle and power system industries. Battery costs are decreasing rapidly as their global and Australian deployment scales up. Therefore, the costs and performance parameters of lithium-ion batteries are adopted in this study to represent battery energy storage. Appendix B.2.1 provides more background on battery technologies as well as their deployment status and costs in Australia.

This study has dealt with rapidly changing costs by considering only sources from 2016 and 2017. With comprehensive coverage of major use cases for energy storage, and with costs for batteries broken down into components, Lazard (Lazard, 2015) is a good starting point, which has also been updated (Lazard, 2016). The use cases correspond to a wide range of power capacities from residential 10 kW systems to transmission-connected 100 MW systems. Other key institutional sources were the US Electric Power Research Institute (EPRI) (Damato *et al.*, 2016), which also covers a wide range of scales, and the National Renewable Energy Laboratory (NREL) (Ardani *et al.*, 2017) for residential battery systems. These sources were supplemented with data obtained (in confidence) from interviews with Australian industry stakeholders to produce a comprehensive range of cost estimates for the installed costs of lithium-ion battery systems.

Final results chosen are shown in Table 3 along with other key performance parameters based on a consensus from reference sources.

This cost model assumes that the PV farm and the battery system are connected by high voltage AC. There are more directly connected systems still under development that may provide some future cost saving in this area, however there is still a significant investment in power electronics needed to manage and optimal DC to DC connection.

It is remarkable that the fit obtained an exponent of almost 1 for the cost that scales with energy, which indicates direct proportion. Battery cells are packed in large quantities to make large-scale battery systems and the cost of each cell is determined by a global market that is little affected by the scale of a particular project or system. On the other hand, the exponent for the cost that scales with power is close to 0.7, or the 'seven tenths' rule, which has been found to apply to a wide range of technologies across different sectors.

Table 3: Parameters for the battery storage costing model and fitted values

	Specific installed cost	Baseline capacity	Power law size exponent	Life-time	Fixed O&M cost	% average capacity over lifetime	Efficiency	Deployment growth
Energy related	$687,735 /MWh$_e$	1 MWh$_e$	1.0	15yr	2%/yr	90%	90%	30%/yr
Power related	$0.39m/ MW$_e$	1 MW$_e$	0.7	20 yr	2%/yr	100%	100%	30%/yr

Note that the deployment growth estimate is highly speculative. The most likely longer-term trend is considered to be 30%/year, which is less than the 40%/year that tends only to be achievable in the early years of an industry.

The percentage average capacity over lifetime is an average value assuming a regular rate of capacity degradation.

3.2.4. Pumped hydro energy storage

PHES is the most commonly used form of electricity storage in the world today. It involves pumping water from a low-level water source or storage unit to a higher-level one and then later releasing that water to generate electricity. This can be through existing (on-river) hydroelectric facilities or off-river closed loop systems. The advantages of PHES include a long life with no capacity fade and an ability to store energy for long durations. The associated turbines can be variable or fixed speed, with different performance parameters. PHES has grown in parallel with the hydroelectric industry, with serious deployment starting in the 1940s and the number of installations increasing at a steady rate since then. Consequently, it is a very mature technology. Of all the technologies considered in this study, PHES has the greatest dependence in cost and performance on the site chosen. Further technical background and costs can be found in Appendix B.2.2.

Estimating the costs of PHES systems is extremely challenging as projects are site-specific and will vary according to the local environmental constraints. The cost components that vary the most by project are reservoir construction and EPC costs. Projects that utilise existing large lakes or rivers as reservoirs reduce costs by saving on the construction of a reservoir.

A significant contributor to the cost variation is that the energy stored in a reservoir is proportional to the product of the volume and height difference between the upper and lower water storage (head). Thus, the reservoir cost per volume of stored water translates to a cost of stored energy that is inversely proportional to the head.

Sources for cost data used in this study include; a thorough review by the Melbourne Energy Institute (Hearps *et al.*, 2014), recent work at ANU (Blakers *et al.*, 2017). EnergyAustralia's feasibility study for a seawater PHES system at Cultana in South Australia (EnergyAustralia, ARUP and Melbourne Energy Institute, 2017). Internationally, a series of pumped hydro projects was identified using Canaccord Genuity broker research (Canaccord Genuity, 2017). In addition other relevant Australian commercial-in-confidence data have been used in the analysis.

The final results of the study's PHES cost model are shown in Table 4. For both the energy related and power related cost model a size based exponent of 0.7 was hypothesised due to the data fit being insufficient to determine this. It was expected that both elements would show the classic 'seven tenths' economy of scale characteristics given their methods of construction.

Recently Snowy Hydro has completed a feasibility study (Snowy Hydro, 2018) for the Snowy 2.0 project using two existing reservoirs. This was not included because, as an extension of an existing system with dams already in place, the project does not provide directly relevant data for the model. The proposed project would have 2000 MW power capacity and 350,000 MWh of storage, which is very much larger than any other PHES project encountered during this study. The cost is anticipated to be between $3.8 billion and $4.5 billion, which is broadly compatible with the per MW costs seen for international projects but much cheaper on a per-MWh basis, as would be expected given the reservoir capacity is very large and already exists. Transmission costs would be additional, including a 2000 MW line to the NSW grid and a 1300 MW upgrade to the NSW-Victoria interconnector. According to these costings, Snowy 2.0 would be a highly competitive energy storage for medium-to-long durations.

Table 4: Parameters for the PHES storage costing model and their fitted values

	Specific installed cost	Baseline capacity	Power law size exponent	Life-time	Fixed O&M cost	Efficiency	Deployment growth
Energy related	$37,000/MWh	1200 MWh	0.7	30	2%	100%	5%
Power related	$1.50m/MW	200 MW	0.7	30	2%	80%	5%

3.2.5. Hydrogen systems

Hydrogen can be produced by electrolysis of water. The basic technology has been available for many years, however there is now increasing interest in production of hydrogen for use as a transport fuel as well as its role as a source of dispatchable generation. For this study hydrogen is assumed to be coupled with underground cavern storage (based on the systems used for natural gas storage) and adapted gas turbine power generation. More technical detail and costs are provided in Appendix B.2.3.

The base hydrogen storage system studied was a 30 MW electrolyser, 1000 hours of salt cavern storage and a 30 MW combined cycle hydrogen turbine. For the scaling power law, available data combined with information provided by a key manufacturer indicated an exponent of 0.7 was a plausible model for an electrolyser. The electrolyser cost model is mainly based on figures provided by industry representatives during stakeholder consultations, along with some interpretation of the reference. The main source of information on underground hydrogen storage is a Sandia reference (Lord *et al.*, 2011). The final conversion step for a hydrogen-based system is assumed to be a combined cycle gas turbine plus steam turbine system. The commercially available *Gas Turbine World Handbook* (Pequot Publishing, 2014) has a comprehensive cost data set for such systems globally.

It is worth noting that hydrogen also provides the potential option of using the existing natural gas transmission pipeline assets. These pipelines can inherently contain considerable stored energy (a few days of average load) due to the pressurisation of the internal volume. Up to around 15% hydrogen could be stored in this way without modification to the natural gas systems.

It is also worth noting that existing turbine systems could potentially burn a mixture of hydrogen and natural gas, or even be retrofitted to pure hydrogen combustion at much lower cost than a new build system.

Final results of for the cost model are shown in Table 5. In the case of gas turbines, the deployment growth is a representative estimate that could pick up growth in application to hydrogen, some effects of growth in usage overall and ultimately be a proxy for increased uptake of conversion by fuel cells.

Table 5: Parameters for the hydrogen systems costing model and their fitted values

	Specific installed cost	Baseline capacity	Power law size exponent	Life-time	Fixed O&M cost	Efficiency	Deployment growth
Electrolyser	\$1.09m/MW	20 MW	0.7	15	2.0%	65%	20%
Underground storage	\$655/MWh$_t$	20,000 MWh$_t$	0.7	30	5%	90%	20%
Combined cycle gas turbine	\$1.64m/MW$_e$	20 MW	0.7	30	3%	57%	20%

3.2.6. Concentrating solar thermal

CST power systems use mirrors to focus and direct beams of solar radiation to smaller areas, which allow high temperatures of many hundreds of degrees to be reached. The systems almost exclusively use steam turbines to generate electricity in a similar manner to coal-fired power stations. They thus provide synchronous generation with inherent inertia. The global deployment of utility-scale CST systems has been growing strongly since 2006. More details on background, status and costs are provided in Appendix B.3.1.

Establishing a cost model for CST in Australia is challenging for two reasons. Firstly cost data for CST globally is hard to access as the industry is characterised by a relatively small number of large projects in any given year. These alternate between countries and between sub-technologies and supplier consortia. Projects routinely treat installed cost data as commercial in confidence although various details, such as PPA prices, tend to become public. Added to that is the challenge that there is no complete utility-scale CST system yet in Australia.

A salt tower system was adopted for this study as the proxy that establishes the current best practice cost for CST.

Building on previous ITP work (Lovegrove, Jordan and Wyder, 2015). Seven additional external sources of information have been accessed. IRENA (IRENA, 2017) offers installed cost data for all the key renewable energy technologies including CST. NREL (NREL, 2017) has a comprehensive dataset on CST costs. SolarReserve has publicly revealed a capital cost ($650 million) for its Aurora 135 MW salt tower system planned for Port Augusta in South Australia. The *Australian Power Generation Technology Report* (CO2CRC *et al.*, 2015), includes cost data for CST. Price (Price, 2017) has recently published a US-based study. The NREL SAM (Blair *et al.*, 2014) contains cost calculations within its default models. ARENA's request for information (RFI) on CST projects elicited 30 responses from a range of experienced organisations, including two that offered a view on installed costs and many that offered a view on LCOE.

In assessing this data, the highest weightings were applied to the SolarReserve announced cost and the RFI responses. The final results are given in Table 6.

Table 6: Concentrating solar thermal cost model parameters after fitting

	Specific installed cost	Baseline capacity	Capture capacity factor	Power law size exponent	Life-time	Fixed O&M cost	Efficiency	Deployment growth
	$/MW	**MW**			**year**	**%/yr**		**%/yr**
Solar field	$0.46m/MW_t$	600 MW_t	19%	0.9	30	2%	-	20%
Storage system	$26,000/$MWh_t$	1429 MWh_t	-	0.8	30	2%	100 %	20%
Final conversion	$2.40m/$MW_e$	100 MW_e	-	0.7	30	2%	42%	20%

3.2.7. Geothermal

Geothermal energy is the utilisable heat from within the earth's crust, sourced by bringing the heat to the surface in a fluid (steam or water). The fluid may occur naturally in a sub-surface reservoir or have to be injected from the surface. Hot sedimentary aquifer (HSA) geothermal approaches access relatively low (up to 95^{o}C) temperature sources with natural permeability, whereas 'hot dry rock' or engineered geothermal systems (EGS) exploit the heat stored in rocks deep beneath the earth by fracturing the rock to create permeable reservoirs. Geothermal energy systems rely on drilled wells to access heat and, once developed, can produce heat 24 hours a day on demand. While the industry has a strong presence globally, in Australia the interest in geothermal is currently muted. More background detail and costs can be found in Appendix B.3.2

A lack of global precedents for analogous plants and limited Australian data means there are limitations on this study's capacity to assess technology performance and costs. An in-depth study by (Australian Renewable Energy Agency (ARENA), 2014) provides the most authoritative source.

The modelled results for geothermal costs are shown in Table 7. In this case, a single cost parameter is used as there is no meaningful interpretation to an intermittent energy storage aspect.

Table 7: Parameters for the geothermal systems costing model and their fitted values

	Specific installed cost	Baseline capacity	Power law size exponent	Life-time	Fixed O&M cost	Efficiency	Deployment growth
Hot sedimentary aquifer	\$ 6.27m/MW$_e$	50	0.7	30	2%	20%	5%
Engineered geothermal	\$14.00 m/MW$_e$	50	0.8	30	2%	20%	5%

3.2.8. Bioenergy

Bioenergy is by its nature a dispatchable energy source, in the same way that traditional fossil fuels are dispatchable. Bioenergy feedstocks vary widely and include (among many others): bagasse or straw; purpose grown energy crops such as short rotation coppice; waste wood or sawdust from forestry operations; organic waste streams from industry, livestock and food production; and general human activities. Bioenergy generation plants range from small domestic systems to multi-megawatt power stations requiring several hundred thousand tonnes of biomass fuel each year. However, most bioenergy sources are below 100 MW with many in the 0.5 MW to 20 MW range because cost-effective transport distances for lower value fuels restrict the catchment area for the plant.

There are two bioenergy generation technologies considered in this study: direct combustion and anaerobic digestion.

Direct combustion may be used with multiple feedstock types, typically involving a condensing steam boiler and steam turbine. This study considered the costs of a combustion biomass plant combined with purpose grown short rotation coppice (SRC), which are woody crops based on mallee.

Anaerobic digestion (AD) produces a gas that may be used in any form of gas fired generator. It is often primarily selected as a waste treatment option, to be installed where the waste occurs in a wide range of industries from food and beverage to livestock. In most cases, the fuel would otherwise attract a treatment fee and the energy will largely be consumed on site.

The bioenergy technology options, characteristics and costs are discussed in Appendix B.3.3. Information on costs and performance was obtained from a wide range of sources including:

(Stucley et al., 2012), (IRENA, 2015), AETA Model_2013-2, (US Energy Information Administration, 2017), (Arup, 2016) UK, and (Kallis, 2016) as well as local stakeholder consultations.

The values adopted for the model for capex, O&M, fuel cost and additional storage cost for bioenergy are summarised in Table 8.

Table 8: Inputs to LCOE model for bioenergy

Description	Power MW	Storage (MWh)	Capex Au m$/ MW (excluding storage)	O&M fixed % of Capex	Fuel cost $/kWhe	Storage capex $/MWh (electrical)	Power cycle conversion efficiency
Direct combustion boiler & steam turbine with src	15	10,800	$4.89	3.6%	0.0727	27.71	24%
Anaerobic digestor	2.5	3.75	$5.05	5.2%	0	$36,000	34%

3.2.9. Summary

Assembling summaries of all the parameter values for the options of the various subsystems gives the results in Table 9, Table 10 and Table 11.

The analysis has not attempted to quantify uncertainties or ranges in a rigorous manner, however it can be observed that some of the parameters have greater certainty than others. Basic PV and wind values are based on a sufficient number of Australian projects to offer the greatest certainty, and the cost model should be able to predict 2017 costs to around +/- 10%. All other cost model predictions have an accuracy of around +/- 20%. PHES is the most subject to project by project site dependant variation. Cost models from other technologies are challenged by a lack of completed Australian projects with known cost data.

Table 9: Parameter values for variable renewable generation

	Specific installed cost	Baseline capacity	Capture capacity factor	Power law size exponent	Life-time	Fixed O&M cost	Deployment growth
PV utility-scale	$1.87m/MW	100MW	28%	0.89	30yrs	1%/yr	30%/yr
Rooftop PV	$2.00 m/MW	0.01MW	17%	1	25yrs	2%/yr	30%/yr
Wind	$2.18 m/MW	100MW	38%	0.9	30yrs	2%/yr	10%/yr

Table 10: Parameter values for electricity storage

	Specific installed cost	Baseline capacity	Power law size exponent	Life-time	Fixed O&M cost	% average capacity over lifetime	Efficiency	Deployment growth
				Batteries				
Energy related	\$687,735/MWh$_e$	1 MWh$_e$	1.0	15yrs	2%/yr	90%	90%	30%/yr
Plus power related	\$0.39m/MW$_e$	1 MW$_e$	0.7	20yrs	2%/yr	100%	100%	30%/yr
				Pumped hydro energy storage				
Dams	\$37,000/MWh	1200 MWh	0.7	30yrs	2%/yr	100%	100%	5%/yr
Plus power related	\$ 1.50m/MW	200 MW	0.7	30yrs	2%/yr	100%	80%	5%/yr
				Hydrogen storage				
Electrolyser	\$ 1.09m/MW	20 MW	0.7	15yrs	2%/yr	100%	65%	20%/yr
Plus underground storage	\$655/MWh$_f$	20,000 MWh$_f$	0.7	30yrs	5%/yr	100%	90%	20%/yr
Plus combined cycle gas turbine	\$1.64m/MW$_e$	20 MW	0.7	30yrs	3%/yr	100%	57%	20%/yr

Table 11: Parameter values for inherently dispatchable technologies

	Specific installed cost	Baseline capacity	Capture capacity factor	Power law size exponent	Life-time	Fixed O&M cost	Efficiency	Deployment growth
			Concentrating solar thermal					
Solar field	$\$0.46\text{m/MW}_t$	$600\ \text{MW}_t$	19%	0.9	30yrs	2%/yr	-	20%/yr
Plus storage system	$\$26{,}000\text{/MWh}_t$	$1429\ \text{MWh}_t$	-	0.8	30 yrs	2%/yr	100%	20%/yr
Plus final conversion	$\$2.40\text{m/MW}_e$	$100\ \text{MW}_e$	-	0.7	30 yrs	2%/yr	42%	20%/yr
			Geothermal					
Hot sedimentary aquifer	$\$6.27\text{m/MW}_e$	50 MW	100%	0.7	30 yrs	2%/yr	20%	5%/yr
Or engineered geothermal	$\$14.00\ \text{m/MW}_e$	50 MW	100%	0.8	30 yrs	2%/yr	20%	5%/yr
			Bioenergy anaerobic digestion					
Digestor	$1.42m/MW	7.3 MW		0.7	20 yrs	6.5%/yr	100%	5%/yr
Plus biogas storage	$\$12{,}391\text{/MWh}_f$	11 MWh		0.8	20 yrs	6.5%/yr	100%	5%/yr
Plus gas engine	$0.91m/MW	2.5 MW		0.7	20 yrs	6.5%/yr	42%	5%/yr
			Dry Biomass combustion boiler					
Storage	$6.70/MWh	44,384 MWh		1	25 yrs	4%/yr	100%	5%/yr
Plus boiler plus turbine	$4.89m/MW	15 MW		0.7	25 yrs	4%/yr	24%	5%/yr

CHAPTER 4

DEVELOPING DISPATCHABLE COMBINATIONS

4.1. Conceptual scenarios for connection

The interaction of the possible technology combinations for renewable electricity generation with the electrical network can be considered in various ways.

VRE sources of electrical generation i.e. wind, PV, or a mix of the two, can be coupled to the options for storage of electricity (battery, PHES, or hydrogen for example) in a number of real or virtual ways, as shown in Figure 12.

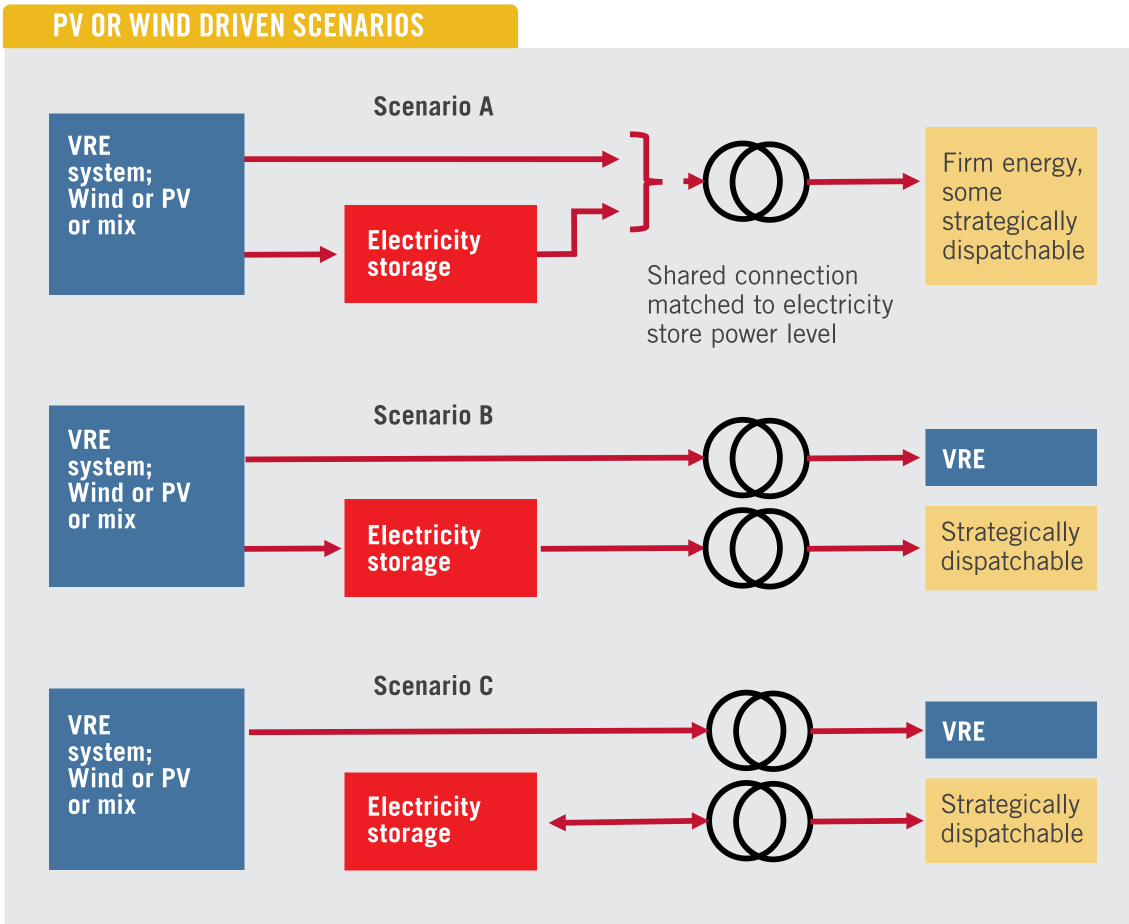


Figure 12: Possible configurations to gain dispatchable power from a wind or PV variable generator coupled to an electricity store (battery, PHES or hydrogen)

In Scenario A, a combined facility with a single grid connection point is considered, with this connection point sized to match the peak discharge power level of the electricity storage system. In this scenario, the VRE system must be sized carefully in an optimum manner relative to the storage capacity and connection size to minimise the average cost of electricity sent out. Optimal configuration for lowest cost of sent out energy may mean that small amounts of curtailment may still be encountered. As discussed in Section 2.2, the electricity exported can be considered in two categories: 'use or lose' (UOL) firm dispatchable electricity and strategic high value (SHV) dispatchable electricity.

UOL energy is that which must be exported or lost when input resource levels are continuing at a high level and production exceeds the rate or capacity at which the store can accept it. This energy is firm because the store can nonetheless vary its behaviour to smooth output overall, and the level of generation can be guaranteed for a period equal to the duration of storage even though that storage may not need to be discharged. Strategically dispatchable energy is that which is in storage when resource levels are low, and can be dispatched at any time. The LCOE of energy sent out can be considered for the whole combined dispatchable renewable generation combination averaged over the total of energy sent out. Alternatively, if a value is allocated to the firmed UOL energy, the LCOE of only the strategically dispatchable energy could be separately evaluated. Depending on market settings, the firm UOL energy will presumably be more valuable than unfirmed VRE but less valuable than the strategically dispatchable energy.

In Scenario B, a VRE system that is presumably considerably bigger in maximum power level than the electricity store is still co-located with it. Conceptually these could be considered as having separate connections or sharing the larger connection of the VRE system. The electricity store can take energy when available from the VRE system and that energy is then available for subsequent dispatch. The VRE system exports a large proportion of its generation straight to the grid in a form that is only partially firmed by the storage.

In Scenario C, the VRE system and the store no longer interact directly and may be in separate locations. Conceptually it is otherwise similar to Scenario B. In Scenario B, the VRE system is more likely to be either a PV farm or wind farm only. In Scenario C, the VRE can be whatever mix of input is arranged contractually. However, the electricity cost for the input to the electricity storage in C would comprise not only the energy cost from the VRE but also the network charges to supply the storage from the VRE (no network charge applies for co-located generation and storage).

LCOE evaluation is undertaken in the same way for Scenarios B and C. In both scenarios, the energy storage subsystem can have a role in firming some portion of the VRE when it is available.

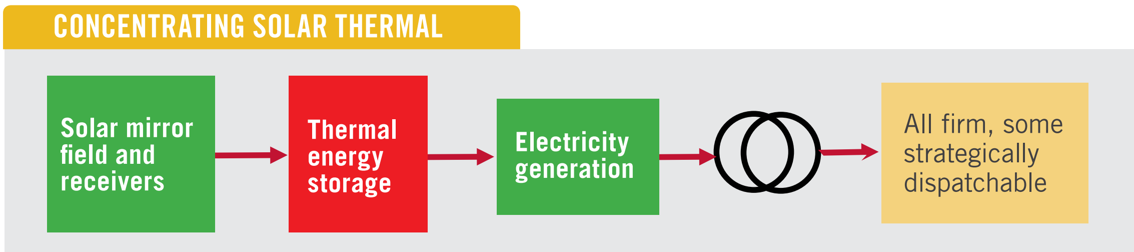


Figure 13: Configuration for achieving dispatchable power from a concentrating solar thermal generator

A CST system must process all collected energy through its storage subsystem, passing from solar field to thermal energy store to electricity generation subsystems before being dispatched as a mix of firm 'must send out' energy and strategically dispatchable energy, as shown in Figure 13. For every level of storage there is an optimum solar field size (often expressed in terms of a solar multiple). If storage is full and solar input exceeds the electricity generation capacity, then some energy will unavoidably be lost. In an optimal system this loss will only be a small (say <10%) fraction of total energy.

Configurations for bioenergy or geothermal-based generators with a stored fuel or constant energy source are illustrated in Figure 14, Figure 15 and Figure 16.

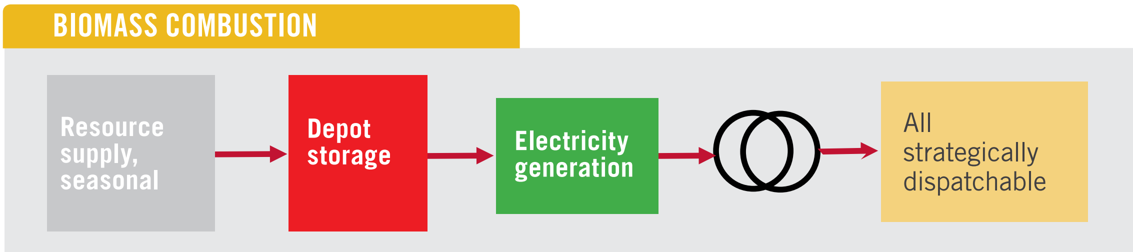


Figure 14: A biomass combustion generator – inherently dispatchable

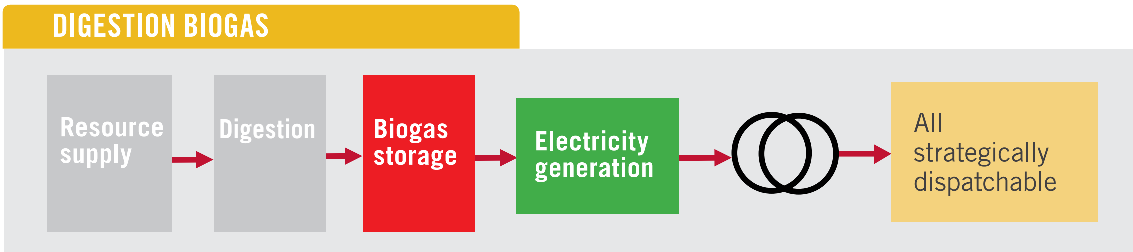


Figure 15: Configuration for achieving strategic high value dispatchable power from a biomass digestor plus gas engine generator

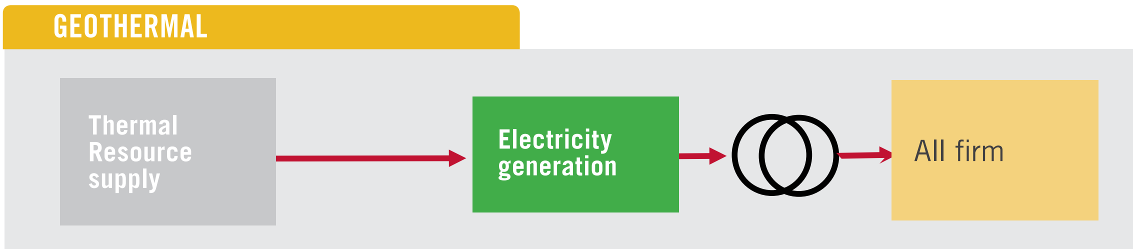


Figure 16: A geothermal generator is inherently dispatchable

These are conceptually the simplest. Generation can be dispatchable and continuous or all the output can be characterised as strategic high value if plants are configured to run only in peak demand periods, including the addition of fuel as needed. Biomass combustion is inherently dispatchable, as the operator decides when to run. As with fossil fuel-based plant, there may be requirements for a minimum stockpile of fuel, for example three months' worth, to allow for supply chain disruption.

4.2. Different perspectives on dispatchable renewables

This study considers dispatchable renewable generation, of which electricity storage subsystems are a part for VRE-driven combinations. However, electricity storage does not need to be linked to particular VRE generators either physically or contractually.

4.2.1. Renewable energy generator perspective

This study examines combinations of matched collectors and firming capacity. Although it is not an explicit assumption, the study also considers an implicit question from the perspective of the VRE collector agent. Namely, what would it cost a PV or wind farm developer to firm up part or all of their output and how does this compare with the cost of inherently firm technologies such as CST, geothermal or bioenergy?

4.2.2. System-wide approaches

However, there are other perspectives that could be adopted. For instance, much of the existing literature looks at how much firming would be required for a NEM with varying levels of VRE up to 100%. The consensus from such ‘integration studies’ reported to date is that, for the most part, around 30% to 40% of renewable generation would need to be dispatchable. Note that, given this study finds that dispatchable renewable generation over all timescales is affordable, it is likely that identification of a least-cost future generation mix will suggest that more be adopted than the minimum deemed to be ‘required’ on the grounds of system security alone. It clearly is not going to be necessary from the system perspective for every VRE plant to have all its output firmed or matched by dispatchable generation.

4.2.3. Individual firming suppliers

A third perspective is that of the individual firming supplier that is developing a standalone electricity storage system. If, for instance, a pumped hydro system or battery is built, it can earn a ‘merchant’ return by arbitraging high and low power costs without an associated renewable energy generation source. (Note that the system owner may instead pass on the merchant risk to other parties by entering cap or swap type contracts, but the underlying arbitrage potential would drive the value). Appendix D has explored the potential for such price arbitrage income and the result is that a MWh of energy passed through storage for arbitrage has a higher value than the average market price, but not spectacularly so: this was an average of $113/MWh in NSW and $240/MWh in SA in 2016. This value declines as more hours of storage are added. In principle, this could be considered as value added to the value of the energy from a renewable generator and sold to the market without arbitrage, but for an individual firming supplier not associated with a single generator this is not a valid calculation as the storage facility should be self-supporting.

Rather, this can be considered an estimate of the value of firming storage capacity surviving in the present market without any additional mechanisms to support it. However, some care must be taken in interpreting this estimated revenue. On the one hand, the assumption of daily cycling means it is a lower boundary to what might be achieved by a smart control system responding to, and predicting, real-time prices. On the other, if the storage facility intends to earn revenue by some means for firming services to renewable generators, those services will compete for the same storage capacity that is assumed to be fully available for arbitrage. Such interaction of different storage applications is a topic of high interest to the energy storage industry; it is difficult to model and experience is being obtained through commercial projects. It is likely to have a significant, though not catastrophic, impact on revenues.

For a CST or bioenergy plant, the underlying question is whether the likely wholesale energy market plus other income offer a sufficient return based on the LCOE predicted. This study provides some insights into the question but does not explicitly address it. To the extent that this study looks at the question, the answer seems to be that it would be difficult for a developer to build a firming plant and be confident of earning a return in the current market on a fully merchant basis. However the probability of a return can be improved through forward contracts with counterparties, as has been achieved with the Hornsdale 100 MW / 129MWh battery in South Australia.

For some technologies, e.g. batteries, the barrier to entry or comparative advantage of any one supplier is very low. Even if a sufficient merchant price arbitrage opportunity did exist, project developers would have to assume the advantage would progressively be eroded as their competitors also sought to exploit it. An obvious example at the moment is for potential developers of PHES to consider the impact that Snowy 2.0 might have on their own plans. This is in contrast to the renewable energy generator perspective, where the addition of an ability to dispatch in a strategic way would lower the risk of market income being eroded.

When considered from these three points of view – VRE developer, system operator, and firming supplier developer – it is clear that the VRE developer has a natural market incentive to provide some firming to their output. PV and wind developers in Australia, and overseas, are already either installing modest amounts of battery storage or having sites that are storage ready. Such storage provides the VRE developer with options around price and is important particularly where a duck curve from rooftop PV is depressing daytime market prices and is likely to lead to increased curtailment.

4.3. Estimating the cost of firm renewable generation

4.3.1. Methodology

The cost of firm dispatchable renewable energy has been established using standard calculations of levelised cost of energy, and considering these as a function of the configuration of subsystems.

For solar and wind driven systems a simple dispatch model was developed using real hour by hour solar or wind inputs to explore the relationship between the various amounts of storage and energy collection.

For geothermal and bioenergy systems, input energy was assumed to be continuously available and instead the impact of restricting operation to reduced hour per day with the assistance of buffer energy storage was considered.

Levelised cost of energy calculation

An LCOE calculation amortises input costs, operation and maintenance costs, and the installed cost and financing for a system's generated energy over its lifetime. In much of the published analysis that informs electricity policy, single LCOEs per technology have traditionally been used in a rather misleading manner to compare generation technologies that are variously continuous, peaking or variable. This study uses LCOE to compare dispatchable renewable options where the LCOE is presented as a function of the hours of stored energy (for solar or wind inputs) or the hours of delivery per day (for bioenergy or geothermal systems) that is achieved.

For this investigation, a simplified LCOE calculation that applies for a single effective discount rate was applied:

$$LCOE = \frac{(F_R + \mathrm{OM}_{fixed})C_0}{PF_c} + OM_{\mathrm{var}iable} + \frac{c_{in}}{\eta}$$

Where:
C_o is the full system installed cost at time 0
P is the nominal capacity (e.g. MW)
F_c is the annual average capacity fraction (%)
$F_R \equiv \left(\frac{DR(1+DR)^n}{(1+DR)^n - 1}\right)$ is the capital recovery factor (e.g. %/year), which depends on *DR* the discount rate which is usually equal to the weighted average cost of capital (WACC) for the project and n is the number of intervals (e.g. years) in the project life
OM_{fixed} is the fixed operations and maintenance cost expressed as a fraction of installed cost per year
$OM_{variable}$ is the variable operations and maintenance costs expressed as cost per unit of sent out energy
C_{in} is the cost per unit energy of any input fuel or energy required (appropriate for bioenergy plants for example)
η is the conversion efficiency between energy inputs to output energy

In this case, the discount rate represents a weighted average cost of capital (WACC) that would follow from assumptions on debt/equity split, interest rates, equity discount rate and tax treatment etc.

Cost of capital

For the renewable energy generation technologies considered here, the capital cost contribution is considerably larger than the O&M costs. The capital contribution is proportional to the discount rate (WACC) used and so the overall LCOE results are very sensitive to that parameter. Choosing an appropriate WACC can be complex and is influenced by assumptions on the shares of debt and equity and their values, plus consideration of risk premiums (Independent Pricing and Regulatory Tribunal, 2018). For this study a baseline value of 6.5%/year has been chosen following from Gerardi et al. (Gerardi and Galanis, 2017). Finkel assigned a WACC of between 6.1% and 7.1% to renewables (Finkel *et al.*, 2017).

Different technologies can be expected to experience different risk premiums for finance according to their level of development and project circumstances, and to external risks such as carbon mitigation. Thus, higher WACCs would apply for real projects involving technologies for which there is less experience. For this study, a single value has been used as representative of a societal perspective that compares the potential of renewable technologies as if they had all reached a similar level of maturity and no additional risk premium was considered in financing.

Determining annual energy generation

To compare technologies, the results presented here are for the simplest dispatch strategy that follows the idea of smoothing and extending for wind and solar inputs as per Figure 2 b) and c), that is providing energy ranging from immediately firm to extended firm in nature.

For dispatchable systems based on wind or solar as the primary energy input, a simple dispatch model was established using real historical hour by hour resource data. The principles of operation modelled are:

- collected energy charges storage as first priority
- when storage is full, energy is sent out if input is in excess
- preferred start time and desired daily hours of generation determine dispatch of fully flexible energy from storage
- electrical storage charging rate equals discharging rate
- CST charging rate set by solar field, discharging rate set by power block.

The study has assumed that charging storage has priority over energy to be sent out, based on the understanding that strategically dispatchable energy will almost always have a higher value than immediate dispatch, although it is possible that there could be situations where this is not the case.

The hourly collected energy traces were established by taking the recorded generation data from real PV and wind farms without storage and then normalising this to the maximum output in a year such that the trace becomes a fraction of peak output. Within the model, this is then multiplied by the capacity of collection being investigated. In the case of CST, traces were generated using the NREL

SAM model for a salt tower system (see discussion in Section 3.2.6). A real year solar input file was used and the trace constructed from the modelled thermal output of the receiver.

For the analysis presented here, the PV trace used has been derived from the output of the Broken Hill PV farm in 2016, the wind trace from the Gunning wind farm's 2016 output and the CST trace from a model for Cobar using 2016 solar data. A trace for 'grid VRE' was constructed from the average of the Broken Hill PV and Gunning wind traces. This grid VRE trace does not account for the benefit of geographic diversity in VRE production that could be achieved by a storage entity sourcing energy from the grid.

In reality, the owner/operator of a dispatchable generator will have a complex and evolving approach to determining dispatch that would consider factors including:

- anticipated primary energy resource availability
- anticipated energy resource availability of other generators
- anticipated system demand profile
- likely behaviour of other market players
- likely wholesale price of energy
- contractual or market signals for other services or provision of firm capacity.

Configuration for minimum LCOE

The ratio of collection capacity to nameplate capacity was examined to derive levels of collection as a function of hours of storage for each technology combination that minimised the overall LCOE. This is illustrated in Figure 17 using the example of a PV plus battery system. A collection multiple of 1 represents a system that is matched to output power level exactly when efficiencies are taken into account. Note this is not to be confused with an optimum ratio of collection to storage across the NEM as a whole or the optimum that a project developer may wish to adopt under specific circumstances. The optimisation assumes all energy that can be sent out is able to be utilised. If market dynamics mean there is greater demand for strategically dispatchable energy than for firm and extend energy, for example, then a different (smaller) collection multiple would be preferred.

This is appropriate for a firm and extend operation targeting daily cycles where immediate generation has significant value, but extended strategically dispatchable generation is assumed to have a higher value. Other scenarios, such as minimising the cost of the strategically dispatchable component if the value of firm UOL energy were known, would give a different value for LCOE overall depending on the value assumed for UOL energy.

OPTIMAL COLLECTION SYSTEM CAPACITY

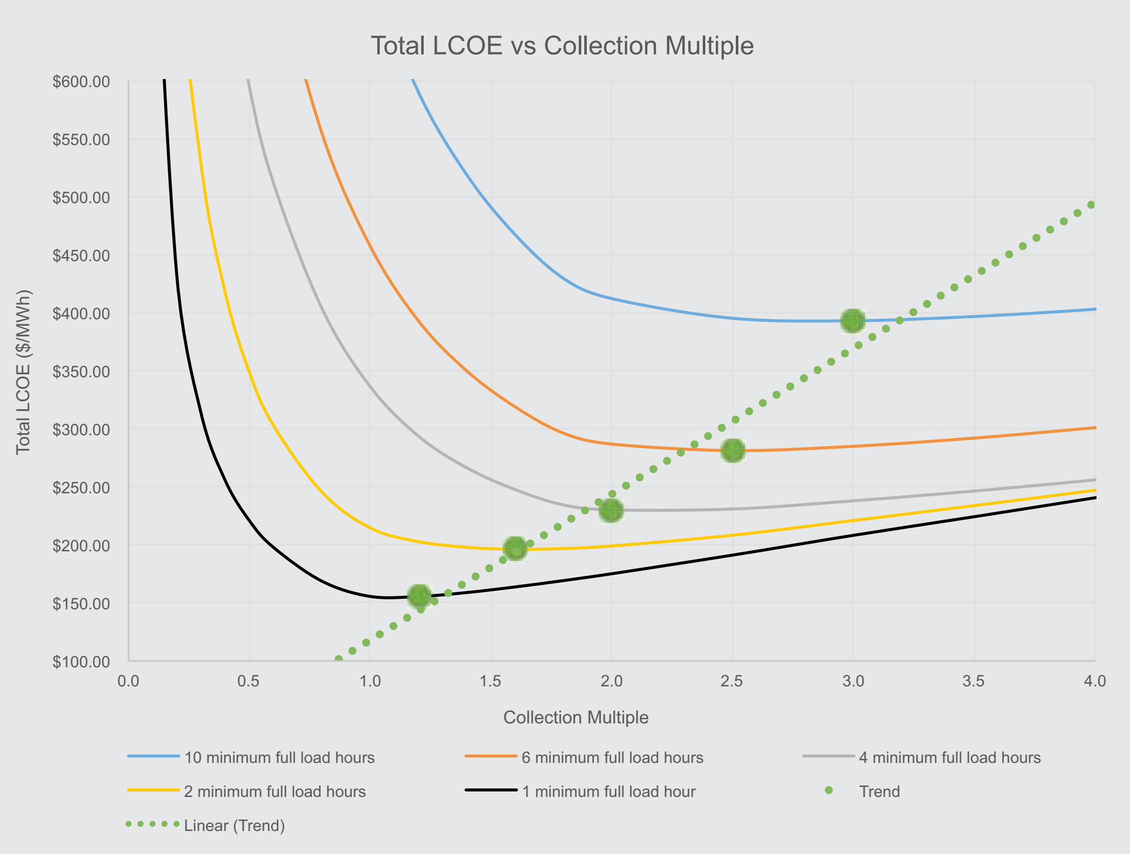


Figure 17: Identifying optimal collection system capacity for each level of energy storage for the case of dispatchable generation from a battery matched to a dedicated PV array

Empirical relationships were established between systems with levels of collection that were optimised to minimise output electricity LCOE for each storage duration and the:

- overall sent out energy capacity factor of the generator
- collection multiple.

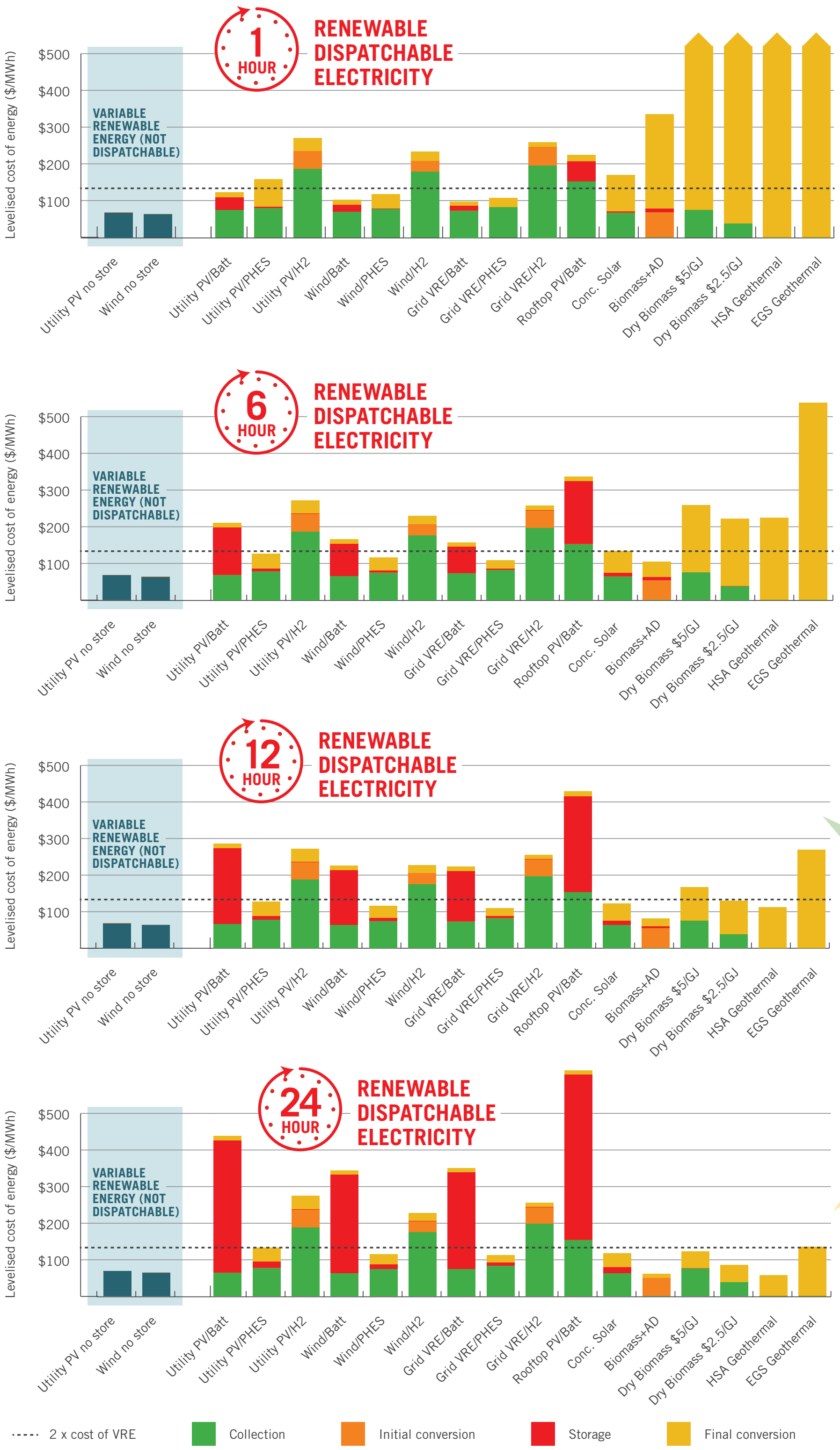
These were then imported to a further tool that calculated LCOE for each technology combination for a given nameplate system capacity and year of applicability, and used to examine the dependence of LCOE over storage hours and other sensitivities. This tool also predicts the LCOE for biomass and geothermal systems where the 'hours' variable is used not as the hours of storage but as the fixed hours of operation per day.

4.3.2. Comparing all technologies

LCOEs for the different combinations at zero, one, six and twelve hours of storage or duration of delivery are shown in Figure 18 and values given in Table 12, Table 13, Table 14 and Table 15. Figure 18 shows the contributions to LCOE for each of the collection, initial conversion, storage and final conversion subsystems in each case. These stacked contributions combine the capex and opex aspects of LCOE for each subsystem contribution.

In the case of the bioenergy and geothermal options, for which a continuously available primary energy resource is assumed, the precise number of hours of generation in a day is the variable, with the system configuration to deliver this modelled for each value. In the case of solar or wind primary inputs, the variable is the hours of storage added to the system, although the actual hours of generation achieved is higher than that number and does vary from day to day. Thus the LCOEs for wind- and solar-driven options compared to bioenergy and geothermal are somewhat comparable but should not be seen as offering one for one equivalent behaviour. Values for PV or wind generation without storage are also included for reference and are seen to be lower cost than the majority of the dispatchable solutions.

As storage hours or hours of operation are increased, the contribution to LCOE from energy storage for solar and wind driven combinations increases, simply because more storage is required. At the same time, the contribution from the conversion aspects decreases because the subsystem investment is amortised over greater amounts of energy generated due to the higher capacity factor of operation. In each case the collection method’s contribution to LCOE does not change in a detectable manner as the number of storage hours change. Although greater levels of collection are incorporated as storage is increased, this is essentially in proportion to the increased level of generated energy sent out over the year. There is a very small effect from the size dependence of cost, which is imperceptible in the graph. It is notable however that different combinations with the same energy collection (e.g. the various PV driven options) have considerable variation in the LCOE contribution from collection. In all cases it is higher than the LCOE of PV alone. This arises from the combined effects of non-unity efficiencies within each of the subsystems plus small amounts of (optimised) collection curtailment, which means the total sent out energy is always less than the collected energy.



Figures show the contributions to LCOE for each of the collection, initial conversion, storage and final conversion subsystems in each case.

For each timescale there are **multiple cost competitive options** below the line representing 2 x the cost of VRE

For each timescale different technologies are seen to offer the **lowest cost energy**

Each technology has timescales and configurations for which it is best suited.

Figure 18: Levelised Cost of Energy (LCOE) for the different combinations at zero, one, six and twelve hours of storage or duration of delivery for systems at 100MW$_e$ nominal capacity evaluated with a 6.5% weighted average cost of capital.

Table 12: Comparison of installed cost and LCOE for PV and wind without storage

No storage, 2017 costs	Total specific cost	LCOE at 6% WACC	LCOE at 6.5% WACC	LCOE at 7% WACC
	m$/MW	**$/MWh**	**$/MWh**	**$/MWh**
PV no store	1.87	65	**68**	71
Wind no store	2.18	61	**63**	66

Table 13: Installed cost and LCOE for 1 hour storage/duration 100MW systems

1 hour storage, 2017 costs	Total specific cost	LCOE at 6% WACC	LCOE at 6.5% WACC	LCOE at 7% WACC
	m$/MW	**$/MWh**	**$/MWh**	**$/MWh**
Utility PV/Batt	2.89	119	**124**	128
Utility PV/PHES	4.86	152	**159**	166
Utility PV/H2	5.77	260	**271**	282
Wind/Batt	3.26	99	**102**	106
Wind/PHES	4.76	113	**118**	123
Wind/H2	5.74	225	**234**	243
Grid VRE/Batt	0.88	102	**103**	103
Grid VRE/PHES	1.94	112	**113**	114
Grid VRE/H2	4.15	250	**260**	270
Rooftop PV/Batt	2.91	218	**225**	233
CST	4.37	164	**171**	178
Biomass+AD	0.78	327	**335**	343
Dry Biomass	3.41	1,142	**1,177**	1,212
Dry Biomass	3.41	1,104	**1,139**	1,175
HSA Geothermal	5.09	1,293	**1,348**	1,403
EGS Geothermal	12.19	3,094	**3,225**	3,359

Table 14: Installed cost and LCOE for 6 hour storage/duration 100MW systems

6 hour storage, 2017 costs	Total specific cost	LCOE at 6% WACC	LCOE at 6.5% WACC	LCOE at 7% WACC
	m$/MW	**$/MWh**	**$/MWh**	**$/MWh**
Utility PV/Batt	8.93	204	**210**	217
Utility PV/PHES	5.77	121	**126**	132
Utility PV/H2	5.78	261	**272**	283
Wind/Batt	9.23	160	**165**	170
Wind/PHES	5.90	111	**116**	121
Wind/H2	6.46	221	**230**	239
Grid VRE/Batt	4.70	152	**157**	163
Grid VRE/PHES	2.17	104	**108**	113
Grid VRE/H2	4.16	247	**257**	268
Rooftop PV/Batt	8.66	327	**337**	348
CST	5.76	129	**134**	140
Biomass+AD	1.48	103	**105**	107
Dry Biomass	3.41	253	**259**	265
Dry Biomass	3.41	216	**221**	227
HSA Geothermal	5.09	215	**225**	234
EGS Geothermal	12.19	515	**537**	560

Table 15: Installed cost and LCOE for 12 hour storage/duration 100MW systems

12 hour storage, 2017 costs	Total specific cost	LCOE at 6% WACC	LCOE at 6.5% WACC	LCOE at 7% WACC
	m$/MW	$/MWh	$/MWh	$/MWh
Utility PV/Batt	14.92	277	**286**	295
Utility PV/PHES	6.28	121	**127**	132
Utility PV/H2	5.79	261	**272**	283
Wind/Batt	15.10	218	**225**	232
Wind/PHES	6.52	110	**115**	120
Wind/H2	6.77	218	**227**	236
Grid VRE/Batt	9.29	215	**222**	229
Grid VRE/PHES	2.37	105	**109**	114
Grid VRE/H2	4.17	246	**256**	266
Rooftop PV/Batt	14.41	415	**428**	441
CST	6.61	117	**122**	127
Biomass+AD	2.28	79	**81**	83
Dry Biomass	3.43	164	**167**	170
Dry Biomass	3.43	127	**130**	133
HSA Geothermal	5.09	108	**112**	117
EGS Geothermal	12.19	258	**269**	280

Table 12, Table 13, Table 14 and Table 15 also show the sensitivity to the choice of WACC, with evaluation at 6%, 6.5% and 7%. With capital costs dominating, LCOE increases almost in proportion to WACC and the relativity between the technologies is unchanged. The exception is dry biomass where there is a fixed and significant fuel cost. A higher WACC increases the LCOE more for a technology with high capital cost and no fuel costs. The WACC chosen can consequently impact on the comparison between renewable and fossil fuel options where the fuel cost can be a major LCOE contribution.

The results for particular technology combinations are presented in Sections 4.3.3 to 4.3.9.

4.3.3. Batteries with wind or PV

Combining batteries with PV, wind or a grid VRE mix gives LCOE trends that start low and grow quite steeply with increasing amounts of storage as shown in Figure 19, which plots the LCOE as a function of hours of storage. The thickness of the plotted lines is designed to convey an approximate sense of the combined uncertainties and project to project variation that might be expected. The grey band labelled as overall dispatchable renewable energy indicates the range of cost that is expected when the best performing technology options are considered for each value of storage hours.

The trend observed for the battery solutions follows from the relatively low cost per unit power coefficient combined with the relatively high cost per unit stored energy coefficient of battery systems. The lowest LCOEs of all options occur at a storage level of around half an hour. This illustrates that short duration batteries are particularly suitable to the smoothing of wind and PV electricity generation to reduce ramp rates in the case of sudden changes in resource levels. In comparison to other options, batteries appear to remain in a competitive range out to about three hours of storage. Note that flow batteries have not been modelled and would have different results.

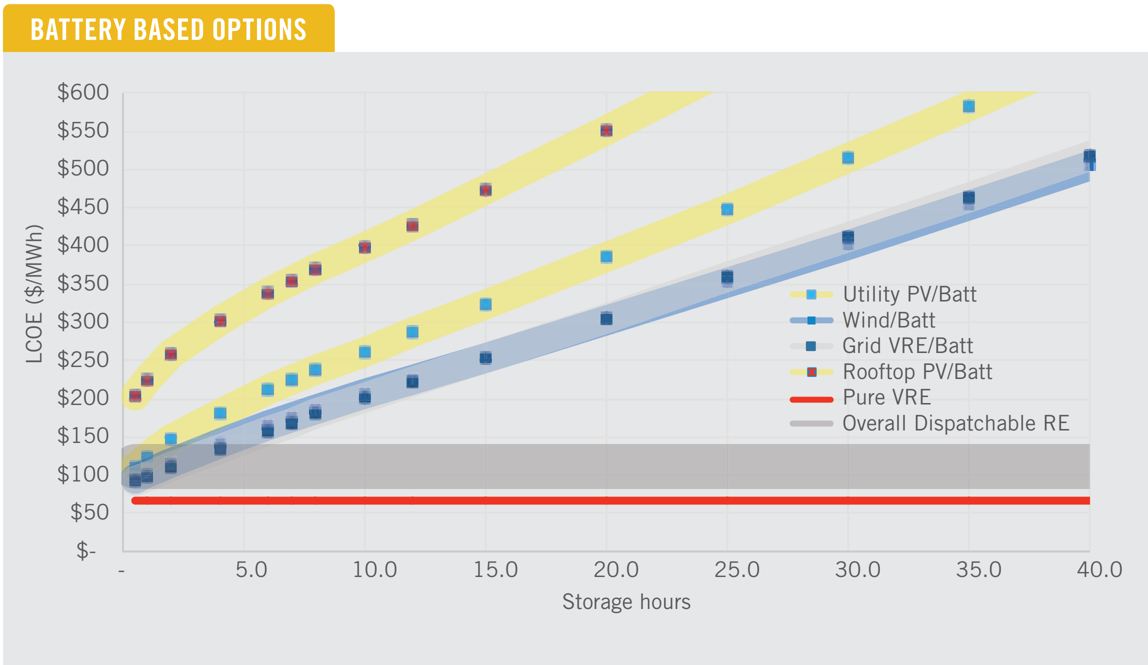


Figure 19: LCOE of firm and dispatchable electricity from battery-based options as a function of hours of storage

The rooftop PV battery case has a higher LCOE than the utility-scale system for two main reasons. Firstly, a lower annual capacity factor of collection is assumed for a coastal city location, along with a likely sub-optimal orientation compared to the inland high solar assumption for optimally oriented, tracking, utility-scale PV. Secondly, the battery and PV systems do not benefit from the economies of scale that the larger utility-scale systems do.

It should be noted that this calculation is made without any assumed income from the RET or other measures. Also, for behind-the-meter operation, the investor sees the comparison with the overall retail cost of electricity rather than the wholesale cost as discussed further in Section 4.3.7.

Battery systems are on a current trajectory of 40%/year growth and so costs should continue to drop quite fast. Wind and PV as VRE input energy also show continued cost reduction trajectories.

4.3.4. PHES with wind or PV

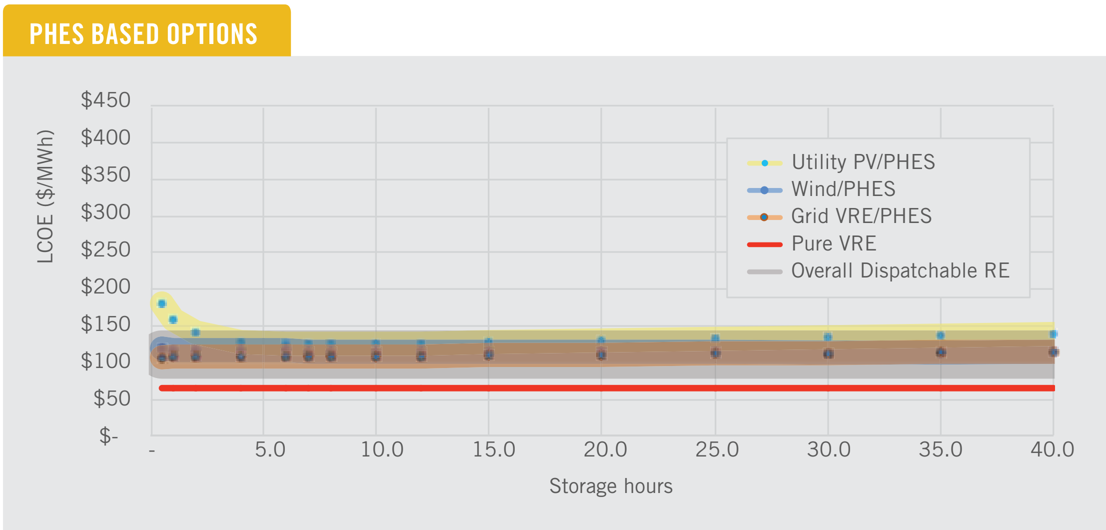


Figure 20: LCOE of firm and dispatchable electricity from PHES-based options as a function of hours of storage

PV, wind and VRE charged PHES offer a competitive and relatively constant LCOE across all durations of storage. The constancy is a consequence of the relatively balanced cost contributions of power capacity and storage capacity to total installed cost. As storage hours are increased, the extra investment in storage is offset by the operation of the conversion components at higher capacity factor as can be seen in Figure 18.

The increase in LCOE at low storage levels for PV driven relative to wind driven arises from the PHES at these storage levels largely just firming up the generation as it occurs. Thus the higher inherent capacity factor of the wind collection over the PV means that the sent-out energy has similarly different capacity factors, with the power related costs of the PHES system amortised over smaller amounts of annual generation in the PV case.

With the serious deployment of PHES beginning around 1940, pumped hydro is the most mature and widely applied method for electricity storage. Global compound growth rates for PHES since then are around 5%/year, with growth over recent years being more linear than exponential. PHES systems are very site specific, so the representative cost formulas adopted will show a high range of variability in reality. The challenge for this sector will be to achieve a cost reduction going forward.

4.3.5. Concentrating solar thermal

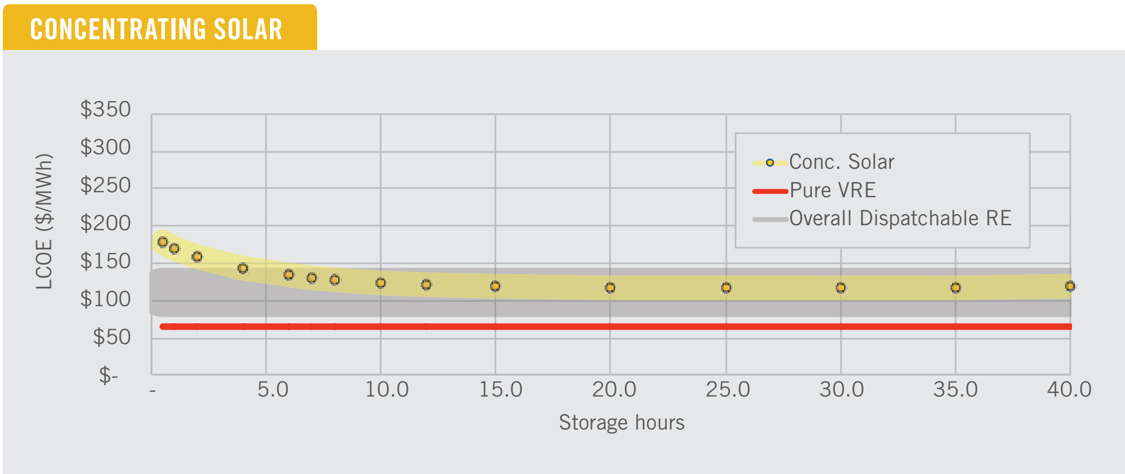


Figure 21: LCOE of firm and dispatchable electricity from concentrating solar as a function of hours of storage

CST systems start to appear competitive from about seven hours of installed storage and upwards. A minimum LCOE is found in the region of 20 hours of storage, however it is a flat minimum. The higher LCOEs for short durations of storage reflect the relatively high installed cost of power related components, while the drop to lower values for longer durations reflects the low cost per stored energy of the molten salt system. From 15 hours of storage onwards, systems will be generating 24 hours a day for many days in summer. As more and more storage is added, and the level of generation increases less as it is constrained by the power block's upper limit for continuous operation, this LCOE rises after the minimum at around 20 hours.

Whilst CST system have been in operation since the mid 1980s, systems with molten salt thermal energy storage have only been applied commercially since 2006. Since then molten salt storage has shown an average growth rate of around 40%/year, although this is very dependent on the policy settings of the countries that have deployed it. The prospects for a good progressive cost reduction depends on the global level of deployment growth that is achieved going forward.

4.3.6. Hydrogen with wind or PV

The results for hydrogen-based storage driven by wind or PV are shown in Figure 22. On this analysis, hydrogen-based systems do not appear competitive over the zero to 40-hour timescale at current costs. The flat nature of the relationship between LCOE and increasing amounts of storage follows from the high cost contribution of collection as a consequence of the efficiency limits of each conversion step. It is not beneficial therefore to increase collection as storage is added. Rather the result is a fixed collection plus electrolyser combination feeding a storage and final conversion system that, as storage is increased, reduces curtailment and allows more cost-effective use of final conversion, with the two cost changes largely balancing.

The high cost of energy is also strongly linked to significant efficiency limitations at all stages in the overall system. Although hydrogen-based LCOEs are high, it is notable that hydrogen is the only technology option for which costs are still trending downward at 40 hours of storage. If a long-term energy reserve was sought using hydrogen, this may need to be in the order of days rather than hours.

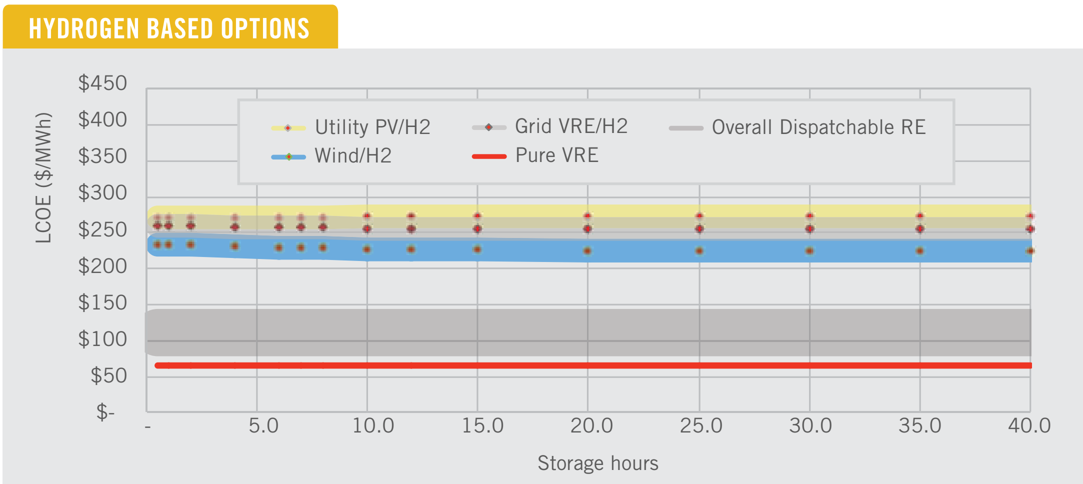


Figure 22: LCOE of firm and dispatchable electricity from hydrogen-based options as a function of hours of storage

To place these numbers in the context of other hydrogen related studies, a dispatchable LCOE of $250/MWh linked to a cost of stored hydrogen that covers the cost of electricity generation and amortisation of electrolyser and storage system has been identified at $33/GJ or $4.7/kg.

Hydrogen systems are now at a point in their commercial development where they are commercially available at scale, but it is too soon to draw any significant conclusions on the likely rate of deployment and cost reduction. Electrolysers and conversion via fuel cells should achieve efficiency and performance improvements and cost reductions as other technologies have done.

There are also some key synergies at play with the hydrogen option. Fuel cell electric vehicles are being actively pursued, particularly in Japan and South Korea. In contrast, in Europe the strong interest in 'power to gas' envisages hydrogen from electrolysis being injected into the existing gas network. Scenarios in which power storage and generation are effectively provided by the existing gas network and gas turbine systems would clearly give a much lower cost of output energy. The development of capability in this area would allow Australia to export renewable energy in an easily transportable form, and hence may feed into liquid fuels production and chemical industry inputs (primarily ammonia) rather than solely electricity.

As wind and solar electricity come down in cost, the impact of low efficiency becomes increasingly less important. Thus, as with PHES, the hydrogen solution could become a cheaper approach to dispatchable renewable generation even if its own inherent costs do not reduce. It can be observed that hydrogen has the lowest cost per MWh of storage capacity of any option and this is considered further in Section 4.5.

4.3.7. Comparing solar storage options

Figure 23 compares the solar specific storage options: PV charged batteries, PHES and hydrogen plus concentrating solar with molten salt thermal storage.

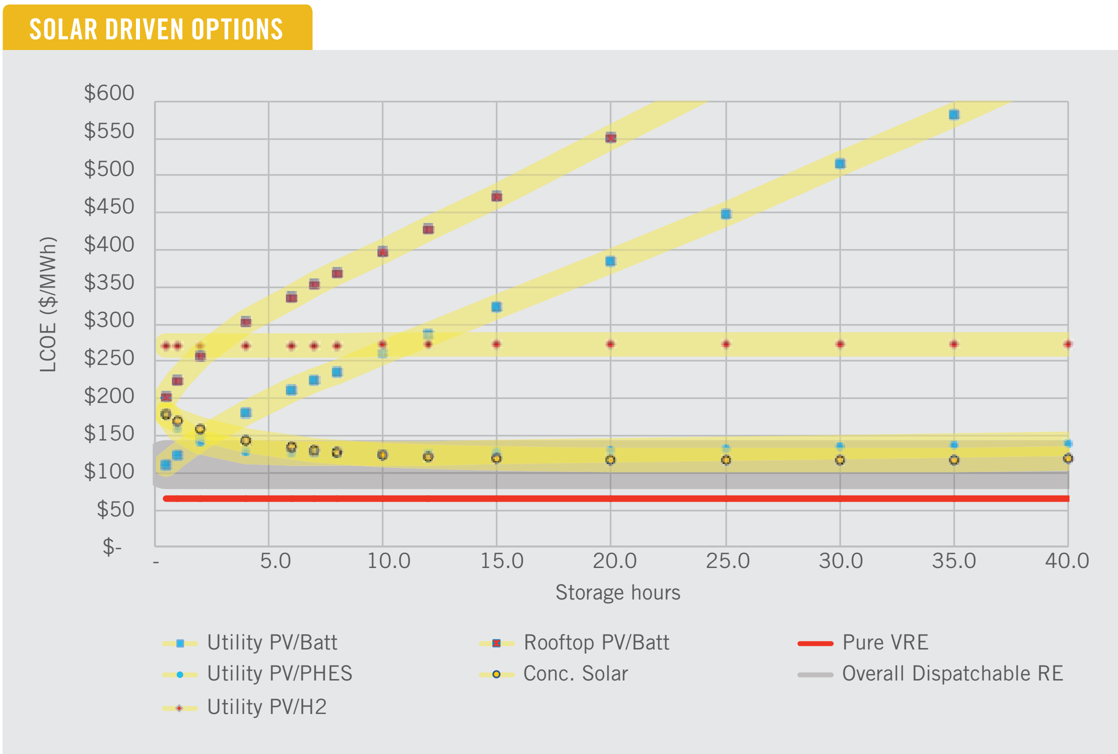


Figure 23: LCOE of firm and dispatchable electricity from solar driven options as a function of hours of storage

Utility-scale PV with batteries offers the lowest cost of firm solar electricity generation for half an hour or less of storage. In order to extend solar generation into evening peaks, PV with PHES or CST offer very similar costs, with CST appearing to have a slight advantage above seven hours and PHES the slight advantage below that level. However, the difference is within the range of uncertainties and the project to project variations that could be expected. As previously noted, hydrogen appears uncompetitive over this timescale of storage.

Rooftop PV with batteries in coastal cities is considerably more expensive than utility-scale, however if it is behind-the-meter then two to three hours of storage could be competitive with retail electricity. It remains an interesting question for debate as to the cost effectiveness from a societal perspective of such an outcome. Much of this hinges on the value of networks and the extent to which they are under-utilised or alternatively close to being constrained such that reducing peak loads could deliver an alternative to expensive upgrades.

4.3.8. Bioenergy

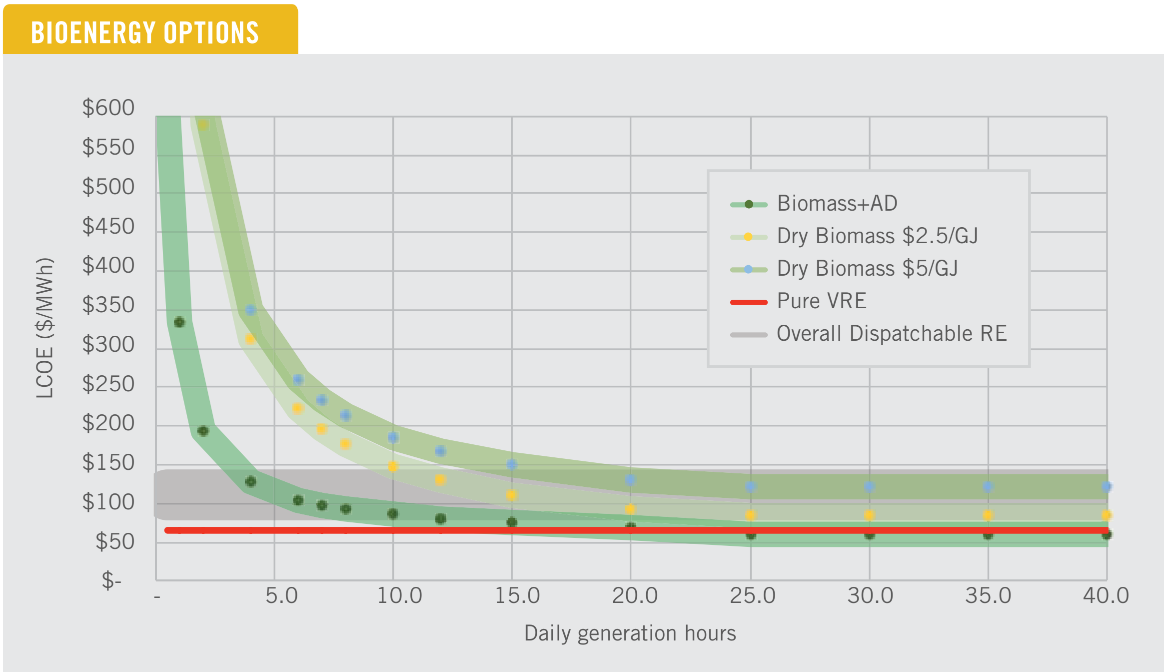


*Figure 24: LCOE of firm and dispatchable electricity from bioenergy as a function of hours of daily generation**

* Note that daily generation hours has no meaning above 24, the axis is simply retained to be consistent with other figures in this section.

For technologies with inherently constant primary energy inputs (bioenergy and geothermal), there is the option of operating as either continuous generation (at lowest LCOE) or at selected high value demand times. The results in Figure 24 show that anaerobic digestion systems operating on zero cost waste and operating at 50% or more capacity factor are the cheapest dispatchable renewable generating option considered. Combustion-based bioenergy generation is also very competitive at 50% or more capacity factor, as long as low cost biomass inputs can be sourced.

Anaerobic digestion of wet wastes is likely to contribute only a small amount to national electricity demand as the available waste material is limited (see Appendix B.3.3), however there is every reason to use it strategically. Dry biomass combustion has the potential to make a much more significant contribution through the long-term development of short rotation coppiced woody crops as well as the potential use of agricultural wastes such as cereal straw.

Adding gas storage after a digestor system allows a system with continuous input to be operated at reduced capacity factor but higher power output, with all the energy provided being strategically high value. LCOE increases as the capacity factor is deliberately decreased to cover the cost of (gas) storage and amortisation of the power block over reduced periods of operation.

Biomass combustion systems typically store fuel in reserve for multiple days of operation. Ensuring such systems can operate year-round as dispatchable power only requires extending the fuel storage to whatever time period is thought appropriate (three months is typical for fossil fuel power stations). It should be stressed this will require the management of potential storage issues such as spontaneous combustion and fuel deterioration, which need to be factored into fuel specifications. LCOE increases as the capacity factor is deliberately decreased to cover amortisation of the boiler and power block over reduced periods of operation, in much the same way as it does for a coal plant.

The bioenergy technologies analysed here are all mature with modest growth in global deployment. Cost reduction potential for these bioenergy options appears most likely to come from development and efficiency in the harvesting, transport and processing of biomass fuels, and perhaps in more complex and advanced system combinations such as gasification plus combined cycle power blocks, which are at a relatively early stage of commercial application.

Use of bioenergy generation in combined heat and power systems is a standard approach that has not been modelled here. Bioenergy offers two revenue streams (electricity and heat), which improves cost recovery and is commonplace in other countries but has not become standard practice in Australia.

4.3.9. Geothermal

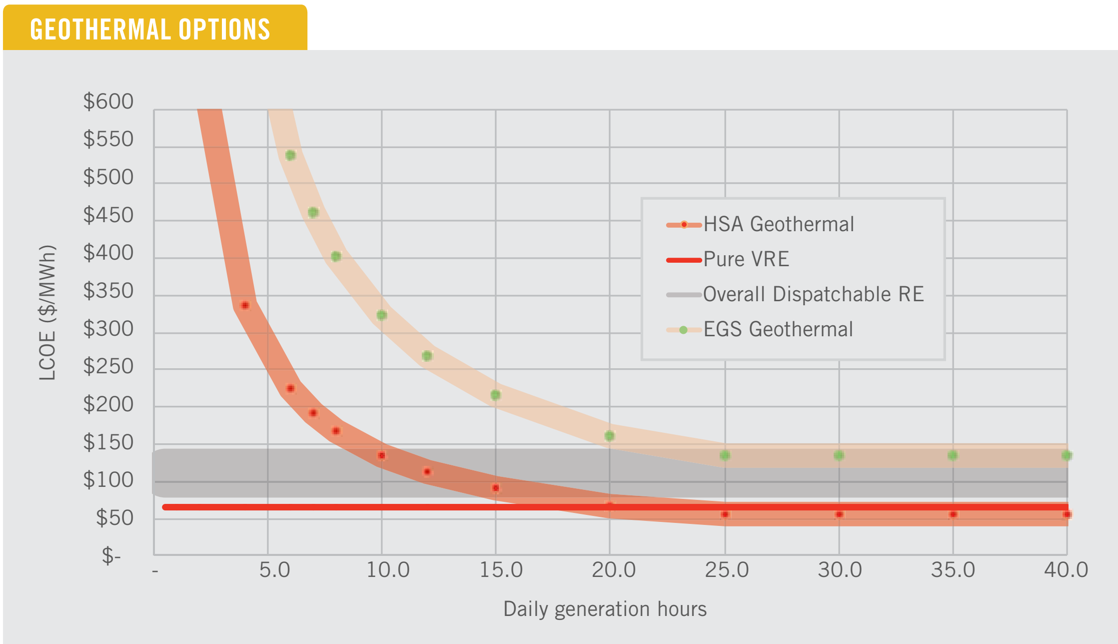


Figure 25: LCOE of firm and dispatchable electricity from geothermal options as a function of hours of daily generation

* Note that daily generation hours has no meaning above 24, the axis is simply retained to be consistent with other figures in this section.

The results in Figure 25 show similar behaviour from geothermal technologies to the bioenergy cases. Engineered geothermal systems (EGS or Hot Dry Rocks) were the subject of much activity and expectation in Australia over the past decade, however the technology has not met those expectations to date. Based on installed costs from ARENA-commissioned studies, EGS is found to offer the potential for costs at the top end of the competitive range when generating continuously. Hot sedimentary aquifer (HSA) systems on the other hand appear quite competitive and close to AD biomass in cost of energy over hours of operation. HSA systems are potentially applicable at modest scale in regional areas of the Great Artesian Basin and other such aquifers. While not the main game HSA appears to have a contribution to make to dispatchable energy in Australia.

4.3.10. Summary

The LCOE from each of the technology options analysed in this study is shown in Figure 26.

It can be seen that while many of the technology combinations are excessively expensive, there are multiple options that are able to deliver a mix of firm and fully flexible electricity from between $65/MWh and $140/MWh at every timescale, with some options costed below $50/MWh. The 'overall dispatchable' line indicates this band of best practice solutions.

The overall message from this graph is that the various options for dispatchable renewable electricity each have times at which they are most cost effective, and these times overlap to a considerable degree. There is certainly no single winner, and at each timescale there are multiple options that fall within a general least-cost band. This is further illustrated in Figure 27.

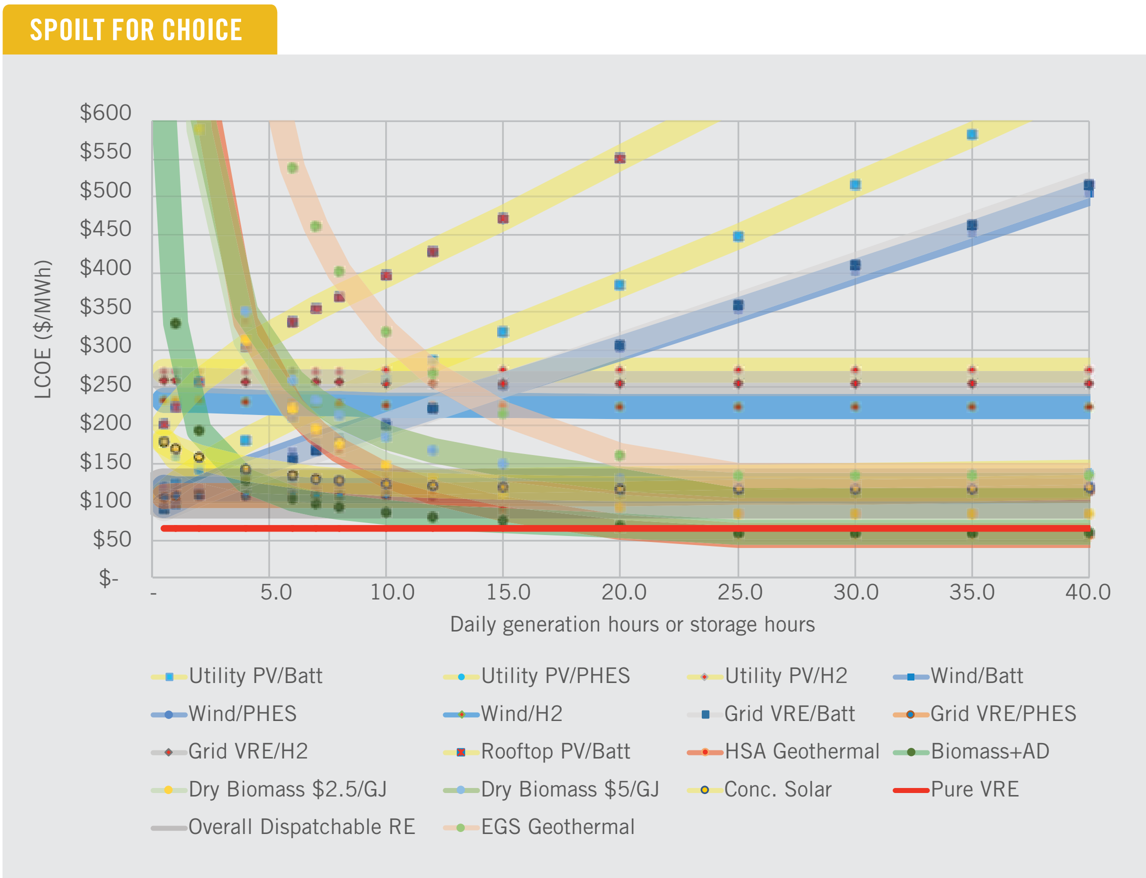


Figure 26: LCOE of dispatchable electricity from renewable generation options as a function of daily generation hours or hours of storage as appropriate for systems at 100 MW output capacity and a WACC of 6.5%/year

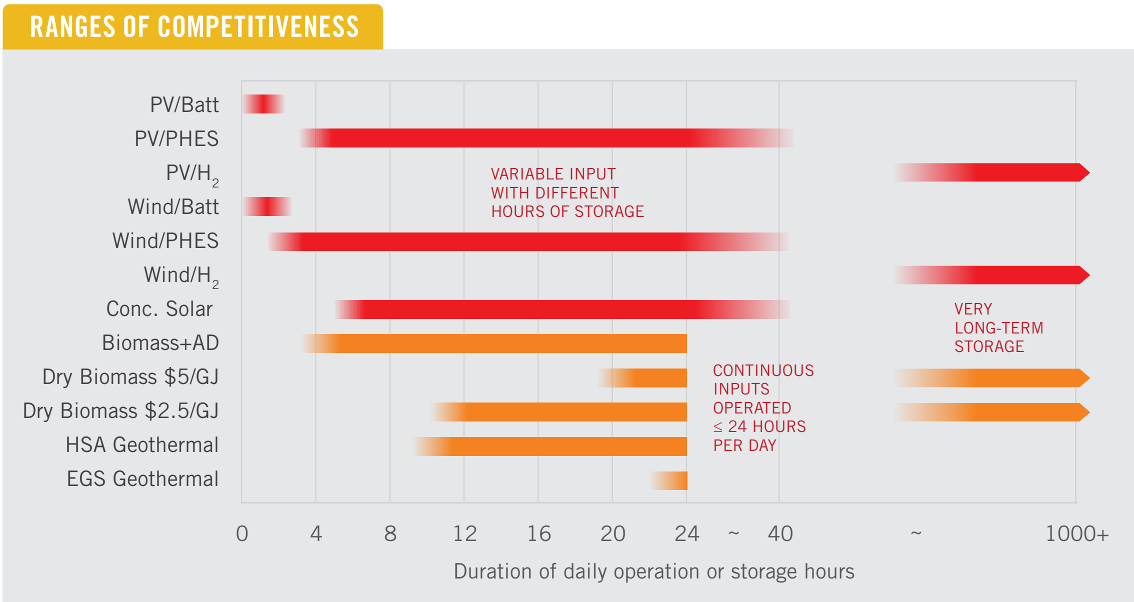


Figure 27: Timescales of storage or operating hours for which each dispatchable combination is most cost effective.

For the bioenergy and geothermal options, all the electricity produced is strategically dispatchable (ie able to be sent out at any time as required). For the options based on wind and solar, the electricity generated is a mixture of firm must send out generation and strategically dispatchable. Since the modelling is for a firm and extend scenario, the fraction of energy that is available in storage after the input resource has fallen away simply increases with the amount of storage. The ratio depends on the level of collection that, for each technology combination, minimises its LCOE. For a PV battery system for example, the ratio varies between 25% SHV and 75% UOL for a half hour of storage to 50% each at 40 hours.

Table 16: Percentage of strategically dispatchable energy for different technology combinations and storage levels between 1.5 and 40 hours

Technology combination	% SHV energy of total output to grid for storage from 1.5 to 40 hours
PV + batteries	26-52%
PV + PHES	26-57%
PV + hydrogen	22-42%
Rooftop PV + batteries	30-55%
Wind farm + batteries	9-60%
Wind farm + PHES	8-58%
Wind farm + hydrogen	8-51%
VRE + batteries	3-35%
VRE + PHES	3-32%
VRE + hydrogen	2-17%
CST	26-93%

4.4. Firm energy variation with year and system size

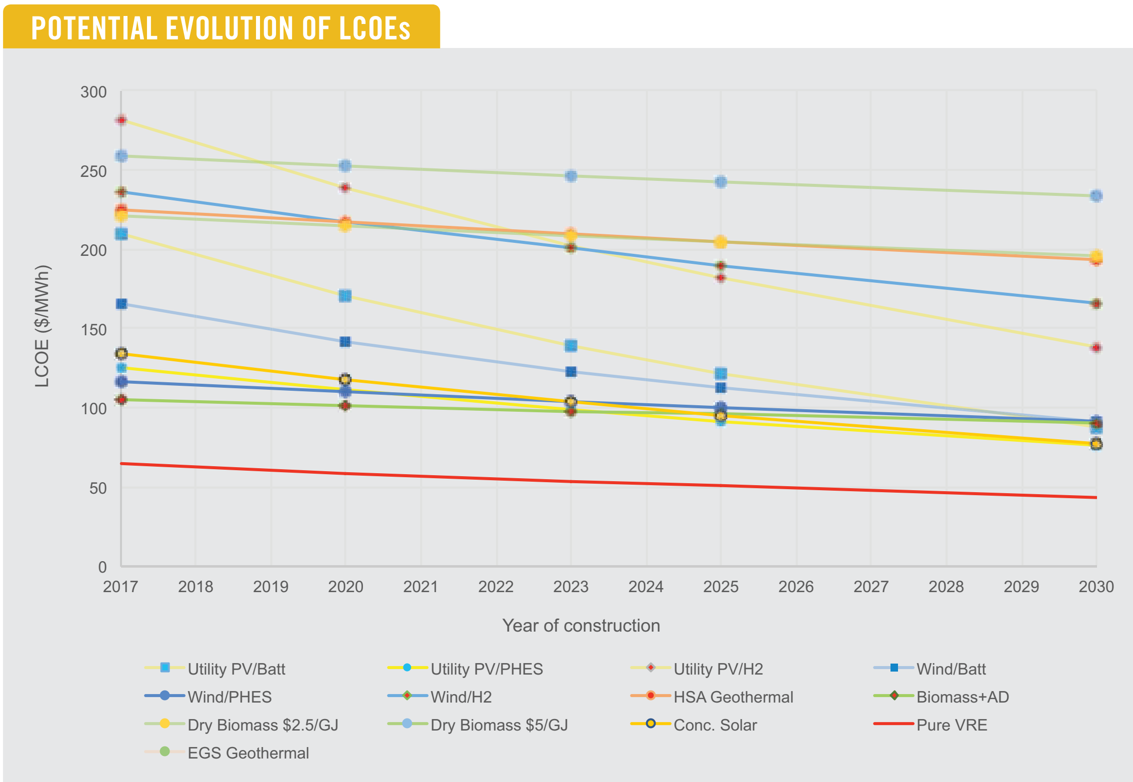


Figure 28: Potential evolution of LCOEs over time for 100MW systems, 6 hours storage/generation hours

Figure 28 examines the potential evolution of LCOEs over time for the case of six hours of storage/generation. The lines are kept thin to ensure that individual trends can be identified. The main observation is that for six hours' duration, if batteries can maintain 40%/year compound growth out to 2030, they will offer dispatchable generation LCOEs at utility-scale that could converge with other options whose deployment growth is assumed to be lower. PV with PHES and CST appear to emerge as lowest cost under the assumptions made. However it should be noted that the uncertainty of future LCOEs grows considerably over time.

Although cost reduction for collection technology and storage technology will differ somewhat, there has not been a re-optimisation of the relative size of collection multiple for each storage duration with these extrapolations. This represents a small increase to the uncertainty of what can only be very uncertain forward projections.

The strongest conclusion that can be drawn is that the relativity is likely to remain between the LCOE for VRE and dispatchable renewable generation at best practice. Individual technologies could see their relative position with competitors shift according to the relative growth in global deployment, although such a trend is unlikely to be clear before 2025.

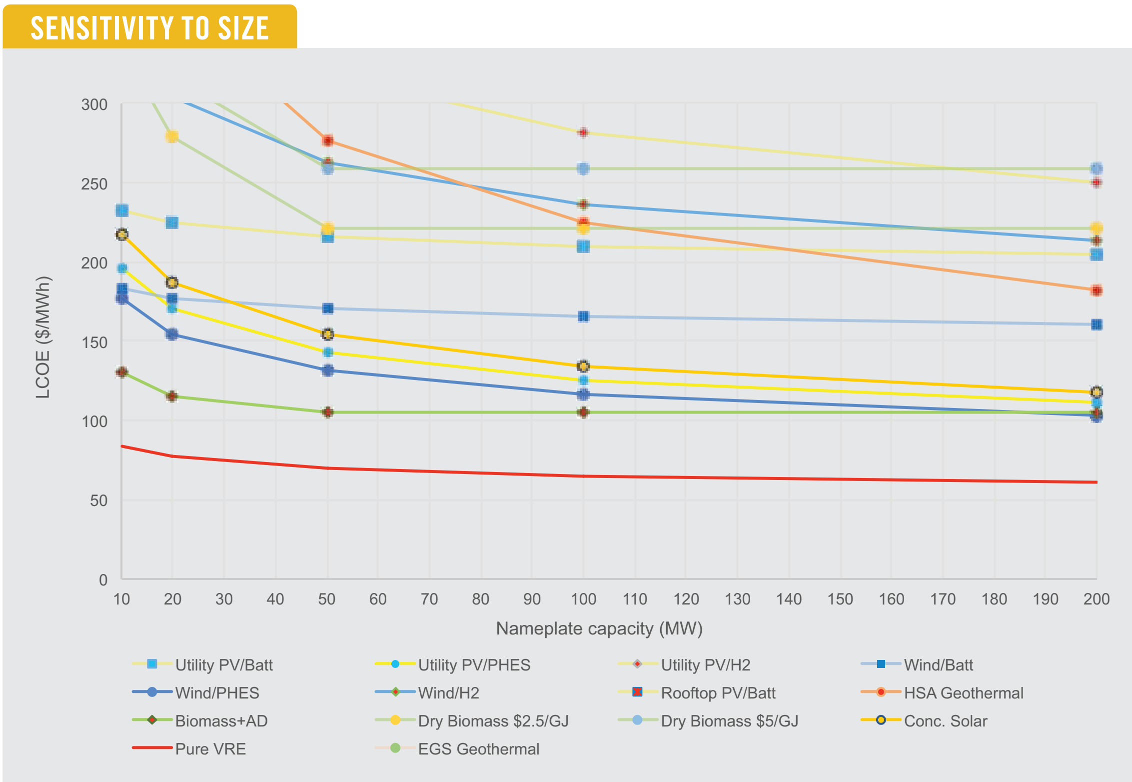


Figure 29: Sensitivity of LCOEs to system size for 6 hours storage/generation hours

Figure 29 examines the effect of system size on cost. Overall, all costs show the underlying power law dependence at various levels according the level of modularity in cost associated with their subsystems. Bioenergy solutions are seen to be constant above 50 MW, as it is assessed that these options are not technically viable at larger sizes and so a larger value is assumed to be built from multiple plants at different locations. Systems based on batteries show a milder variation than others, reflecting the large cost contribution from the stored energy subsystem with its assumed size exponent of 1, as well as the high level of modularity. This means the cost penalty for small systems is less and, on the flip side, the cost benefit of very large systems is reduced over other technologies. Again, the relativity between best choice dispatchable solutions and VRE is essentially maintained irrespective of system size.

4.5. Long-term energy reserves

As high levels of wind and solar sourced energy are added to the system, the issue of infrequent but prolonged periods when both solar and wind input are low over several days may become significant; although a recent study found that short-term requirements for energy security will dominate storage requirements until the penetration of variable renewable generation is well above 50% (Jay Rutovitz *et al.*, 2017). This concern could become acute for areas of the electrical system that have achieved greater wind and solar penetration earlier than the system as a whole, depending on the levels of interconnection.

Energy that is held in reserve for such events could be offered in two ways:

- **Addition of stored reserve energy**: A dispatchable renewable energy system that operates on a regular basis according to energy price signals in the market could have an additional 'long term energy reserve' of additional storage added to it, which is kept fully charged in the event of a low input period or other contingency.
- **Strategic power capacity reserve system**: A dispatchable renewable system could be built solely for operation during periods of a few days on an infrequent basis.

4.5.1. Addition of stored reserve energy

To examine the relative cost effectiveness of technology combinations under the first scenario, Table 17 starts with the cost per additional primary stored energy capacity. The efficiencies of the subsystems are used to convert this to installed cost per equivalent stored electricity. Applying the respective capital recovery factor and O&M cost gives an annualised fixed cost value that is the cost per year of maintaining such a strategic store.

Table 17: Options for long-term energy reserve of dispatchable renewable electricity

Energy storage technology	Specific installed cost per stored primary energy	Specific installed cost per equivalent stored electricity	Annualised cost of capital and O&M per equivalent stored electricity	Addition to LCOE at 5% utilisation	Addition to LCOE at 1% utilisation
	\$/MWh	**\$/MWh$_e$**	**\$/MWh$_e$/year**	**\$/MWh$_e$**	**\$/MWh$_e$**
Biomass depot	\$7	\$29	\$3	\$0.01	\$0.04
Hydrogen	\$655	\$1,768	\$276	\$0.63	\$3.16
Hydro dam	\$37,000	\$46,250	\$4,467	\$10	\$51
Biogas accumulator	\$12,391	\$36,444	\$5,698	\$13	\$65
Molten salt	\$26,000	\$61,905	\$5,979	\$14	\$68
Batteries	\$687,735	\$764,150	\$94,260	\$215	\$1,076

In understanding Table 17 it is important to note that units of specific installed cost for storage (\$/MWh) are also the same as the units for an LCOE, which can be very confusing as these are very different concepts.

It is not in the scope of this study to determine how frequently such a store may be needed, as this would depend on the overall technology mix and the load it is trying to supply. However, by way of example, the final column presents the increment to LCOE if the store were accessed at a 5% or 1% utilisation factor (i.e. equivalent to 2 weeks or 3.5 days of continuous operation per year respectively). These LCOE increments would add to the LCOE of the corresponding firmed system.

It can be seen that there is a very large range. The high cost of establishing stored energy in batteries effectively rules them out as a choice for long-term energy reserve. At the other extreme, storing dry biomass in a depot prior to combustion for power generation is by far the cheapest option. However, it should be noted that depot storage is essentially a standard feature of combustion systems. Thus biomass combustion is only able to provide long-term reserve in its standard configuration, and output could not be ramped up to greater capacity in response to a system shortfall. The comparison is an indicator that biomass combustion plant revenues are likely to be maximised by not only targeting peak daily periods but also extending generation at times of low solar and wind resource. Given the challenges in accessing sufficient biomass for routine plant operation, prioritising availability as a long-term energy reserve may be a worthy consideration.

Underground storage of hydrogen emerges as the next cheapest option and the cheapest that can be driven by wind or solar input. The challenge is that the comparison of firmed energy LCOEs has indicated that options based on hydrogen storage are not cost competitive at the present time.

The remaining options, PHES, CST and biogas, are of equivalent orders of magnitude. These options can be considered as systems that would be operated in a firm and extend manner on a day to day basis where the base LCOEs of between $90/MWh and $140/MWh would cover the collector and conversion systems plus a base level of storage. In extended low sun and low wind periods the extra reserved long-term energy reserve would be covered by an additional $60/MWh to $70/MWh, bringing the cost of the energy in those periods to around or below $200/MWh.

4.5.2. Strategic power capacity reserve

The second scenario, involving a system built entirely to provide long-term strategic power capacity reserve, has been tested by evaluating LCOEs for systems in which one operational cycle per day is modelled for the fraction of days of assumed extra peak demand in excess of other supply. It is assumed that with such infrequent operation, energy from wind and solar to charge the energy store would be sufficiently available on other days.

Results for the case of 20 days per year are shown in Table 18 for a range of storage or operational time durations. In all cases, very high LCOEs are obtained although they are largely below the NEM market cap of $14,000/MWh. Overall it appears unlikely that a dispatchable renewable generation system would be built only for this specific application, however it may be that some level of strategic reserve capacity service could contribute to the overall value contributed by a system operated on a more regular basis.

Table 18: LCOE of options for strategic capacity reserve called on 20 days per year

Energy storage technology	LCOE 1 hour storage	LCOE 6 hour storage	LCOE 12 hour storage
	$/MWh_e$	$/MWh_e$	$/MWh_e$
Biomass depot	$20,100	$3,400	$1730
Hydrogen	$13,500	$2,600	$2,440
Hydro dam	$9,440	$1,820	$1.030
Biogas accumulator	$6,100	$4,640	$2,437
Molten salt	$12,100	$2,295	$1,289
Batteries	$5,500	$4,900	$4,840

4.6. Other services

Delivery of ancillary services, system security and network support is dependent on both the characteristics of the final conversion subsystem and the availability of energy for dispatch when needed. Table 19 summarises the key final conversion system characteristics that are relevant. The dispatchable renewable generation combinations that have been studied for this report are capable of providing many if not all ancillary services and system security support. For further discussion of ramp rates see *(Cavanagh* et al.*, 2015)*.

Inherent system support (stability) has traditionally been provided by systems with inertia and synchronous generation characteristics. Inertia is the inherent angular momentum and stored kinetic energy in systems with heavy spinning machinery. Synchronous generators are those that produce AC generation at a controlled frequency and can be controlled to both synchronise with and help to control the overall grid frequency. Asynchronous generators on the other hand simply follow and reinforce the frequency trends of the grid.

In the event of a sudden catastrophic event in the system (e.g. sudden loss of a transmission connection or large generator) traditional spinning generators can sustain high fault currents for short periods without shutting down. Thus they can better ride through events and provide the high fault currents that enable other parts of the system to respond appropriately in a timely manner.

Synchronous generators with inertia work to inherently limit, in the very short term, the rate of change of frequency that occurs if there is a major event like the sudden disconnection of another generator from the network. There is considerable debate as to the extent this result can also be reliably achieved from suitably configured power electronics (sometimes called synthetic inertia). It is clearly physically possible to do this and in some large-scale grids around the world such as that of Hydro Quebec (DGA Consulting, 2016), wind turbines have been configured to deliver inertia from rotating blades through their power conversion system for many years. Some battery manufacturers are now developing synthetic inertia with millisecond precision as an optional feature of their control system.

Table 19: Characteristics of final conversion subsystems

Final energy conversion technology	Very fast response possible synthetic inertia	Time to ramp from 0-100% output	Synchronous generator with inertia and contribution to current	Possible use as synchronous condenser
Inverter (for batteries or fuel cell)	Yes	100s milliseconds	No	No
Steam turbo generator (biomass or solar thermal)	No	30mins for adapted fast start units	Yes	Yes
Gas turbine generator (hydrogen or biogas)	No	A few minutes	Yes	Yes
Gas engine (biogas)	No	A few minutes	Yes	No
Hydro turbo generator	No	A few minutes or seconds if running as synchronous condenser	Yes	Yes

The advantage of traditional inertia is that it is fail-safe and requires no control actions. Electrical system operators need to build confidence in synthetic inertia as an option for it to be used in substitution. Once they have this confidence, it is quite possible that synthetic inertia could outperform traditional inertia because it can be configured exactly to requirements. For example, it can be configured to prevent 'overshoot' when restoring frequency to the nominal value.

Synchronous condenser operation is the process of spinning a rotating machine in the absence of its working fluid by drawing power back into its generator. Doing so keeps inertia in the system but at the cost of an electricity consumption that is around 1% of the nameplate generator capacity.

AEMO-specified voltage and frequency control ancillary services can be provided at various levels by dispatchable renewable options according to their characteristics and operating states. Some services require response rates that are faster than particular generators can provide. And some services require deliberate generation at below full capacity, while the market demand for energy may motivate full power operation.

All the dispatchable renewable options could be designed to provide system restarting services if required to do so. This means that in a system black event, they can revert to islanded operation running at low power levels to sustain internal loads until called on to reconnect. In a more extreme case, if they themselves have shutdown, dispatchable renewables could have energy reserves and backup systems that allow them to restart without any energy input or frequency signal from the grid.

Further to this, providing reliable network support depends on a high-level probability of energy being available at times of critical need at particular places in the network. A bioenergy or geothermal system can do this if controlled for that purpose. Operation of a long-term energy reserve function for a wind- or solar-driven system would also essentially guarantee firm capacity on command for network support if it was controlled for that purpose.

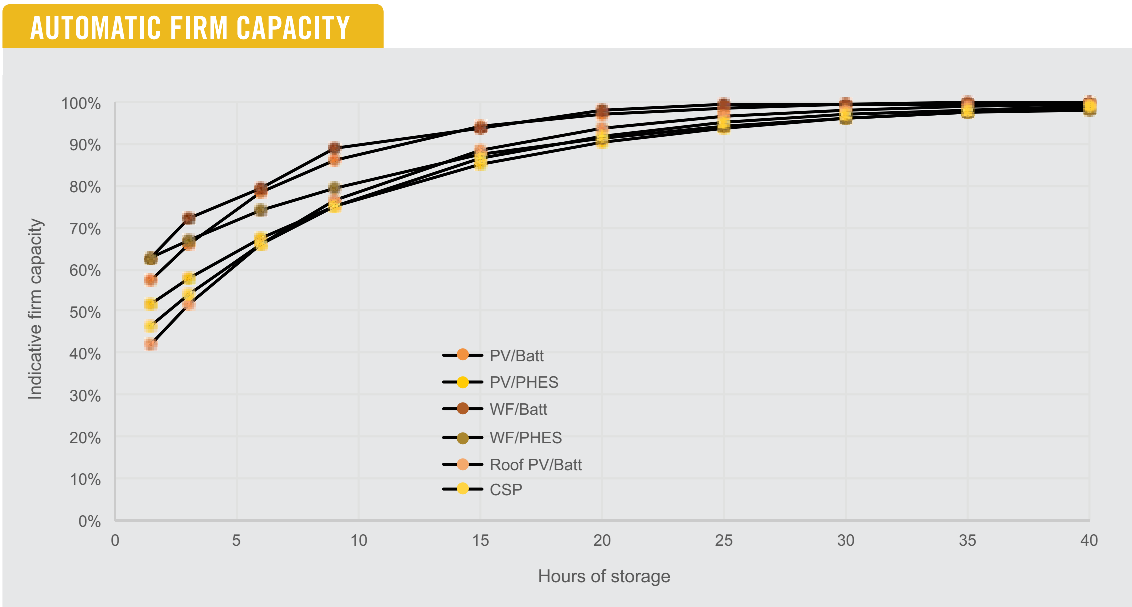


Figure 30: Automatic firm capacity for individual generation and storage options, based on top 10 peak load events in NSW 2016

A system that is sending out energy for maximised energy sale income can also have a high probability of generating at critical times as a matter of course. Modelling the likely output from the solar and wind driven dispatchable generation options in firm and extend mode, and evaluating its probability of generation at times of historic peak load events, allows an 'indicative firm capacity' to be established. Figure 30 shows that when correlating the top ten load events in NSW for 2016 with collected energy traces also based on 2016 NSW records, this 'automatic' firm capacity climbs progressively to 100% as storage is added.

As with all kinds of generation, the firm capacity also depends on the scheduling of planned maintenance and the likelihood of unforeseen breakdowns.

To date ancillary services capability and inherent system security features such as inertia have been abundantly available in Australia's electricity system from fossil-fired generators. In such circumstances the value of these services as an income stream to a generator has been a small fraction of the income from energy sales. The wide range of options for dispatchable renewable generation identified in this study is clearly technically feasible and available within cost of energy ranges that are comparable with new build fossil-fired systems. This suggests that if dispatchable renewable generation is taken up to contribute to meeting energy demand when VRE is not available, they will be able to continue to provide ancillary services and system support as a relatively low proportion of overall electricity system cost.

4.7. Comparison with other options

As the existing fleet of coal-fired power stations progressively retires, there are options for addressing future requirements for dispatchable generation that might be considered in addition to the combinations for dispatchable renewable generation that have been analysed here. These include:

- deliberate partial curtailment of PV or wind to allow controlled variation in output
- demand side response
- new build fossil fuel generation.

4.7.1. New fossil-fired generation

The Finkel Review quoted LCOEs for new build coal of \$85/MWh and gas at \$145/MWh (Finkel *et al.*, 2017, page 205). This is comparable to previous estimates in the *Australian Power Generation Technology Report* (CO2CRC *et al.*, 2015), which has \$80/MWh for ultra-supercritical coal at 85% capacity factor, \$78/MWh for combined cycle gas at 85% capacity factor and \$158/MWh for open cycle aero-derivative gas turbines at 20% capacity factor.

For coal and combined cycle gas the high capacity factor of operation assumed is unlikely under a high renewables scenario, given that new plants would have higher short run marginal cost than wind or PV without storage, likely leading to fewer operational hours. Costs would therefore be amortised over fewer hours, leading to a higher LCOE for those plants. There are also issues of future explicit or implicit disincentives applying to carbon emissions which, combined with the reducing operational hours, would lead to a higher LCOE. Coal plants have not traditionally been built for flexible operation, although this may be overcome in new build coal specifically designed for faster ramp rates. These factors are presumably major contributors to Australia's 'big three' vertically integrated 'gentailers' ruling out future investments in new coal-based generation.

Since coal plants are unlikely to be installed to balance rapidly changing loads and supply from variable renewable generators, the comparable dispatchability option is gas peaking plant at around \$150/MWh for a 20% capacity factor. Whilst this study has not attempted a direct comparison on the same basis of evaluation, it is apparent that the dispatchable renewable options analysed can produce electricity with similar cost of energy and performance characteristics.

However, the competition for dispatchable renewables is more complex when new gas-fired combined cycle generation is considered. Under a high penetration of renewables scenario such plants would also likely be subject to lower capacity factor operation than the 85% value assumed for the \$78/MWh cost of energy figure. Gas generation is an established technology with an emissions intensity lower than coal. However, a major future challenge is uncertainty in the price and availability of gas. Some of the dispatchable renewable options – in particular biogas or renewable hydrogen stored in the gas network – could effectively utilise the same generation equipment, initiating a transition from fossil to partially-renewable gas.

Thus it is apparent that dispatchable renewable options are not yet so cheap that they would be expected to outcompete new build fossil fired systems without some policy mechanism addressing carbon emissions or otherwise supporting them. However the level of support needed to bridge the gap appears potentially quite small. It is also obvious that dispatchable renewable options are not competitive with the short run cost of energy from coal and gas plants whose capital costs have already been amortised.

4.7.2. Demand response

Appendix B.4 discusses demand response possibilities. Studies overseas show that customer sited actions can reduce net load at critical times through a mix of load shedding with shifting and embedded energy storage. By spreading a finite amount of load over customers with different characteristics, the result is a supply curve of accessible load shifting capacity versus cost of avoided energy.

When ARENA and AEMO called for solutions to operate under the reliability and emergency trader (RERT) mechanism beginning in the summer of 2017, a range of demand response (DR) options were proposed (Australian Renewable Energy Agency (ARENA), 2017; Silkstone, 2017). These proposals provided an important price discovery mechanism for DR that was not previously available. The price discovery benefit occurred primarily on the cost of capacity to deliver, because the process included a cap of $1000/MWh to be paid when the demand response is made available, and in practice most proposals requested close to this level. Proposed projects were required to make available demand response of 5 MW or more within 10 or 60 minutes of a call, and be able to sustain that response for up to four hours. The service was to be available up to ten times per year. A range of different technologies, prices and customer options were proposed. This provides some level of benchmarking for the price point at which DR can be made available, and how much may be on offer. Of the 600 MW offered, 203 MW (by the end of year three) was accepted for the trial with prices varying from $30,000/MW to $92,000/MW million per year to establish and maintain a facility for three years.

Costs include development and installation of communication systems, energy management control systems, storage, and onsite generation, as well as project costs such as management, customer recruitment and knowledge sharing. The projects will ramp up to full capacity over three years, and it would be assumed that they could continue to offer services to AEMO for many more years to come. Customers are typically paid a retainer to be available up to six times a year to a maximum of 40 hours. Typically it will be called on less frequently. Given that many of the DR options included load management systems of some form, it would seem that the costs incurred would also allow management of electricity demand under normal grid conditions, thus providing customers with a range of value streams.

Given the large range of options and costs proposed, and that a mixture of load shedding, load management, storage and onsite generation is involved, it is difficult to rigorously assess the likely cost per MWh of DR and hence compare it to other options assessed in this study. Also, projects were selected not just on price but also on their overall contribution to the objectives of the funding round, so do not necessarily represent the lowest cost resources available. However, demand response clearly has potential for short duration use in critical periods.

To place this approach in context, the analysis in Section 4.5.2 has been extended to determine the average cost of energy from a dedicated dispatchable renewable energy generator operated for four hours at a time[4] with a range in the number of events per year, compared with the demand response approach using the $1000/MWh payment plus an amortisation of the average $66,658/MW/year annualised cost of the ARENA-funded trials. The results are shown in Figure 31. It is apparent that the emergency demand response is more cost effective than any of the dedicated renewable generation options, although the digestor biomass systems do cross over at more than ten events per year.

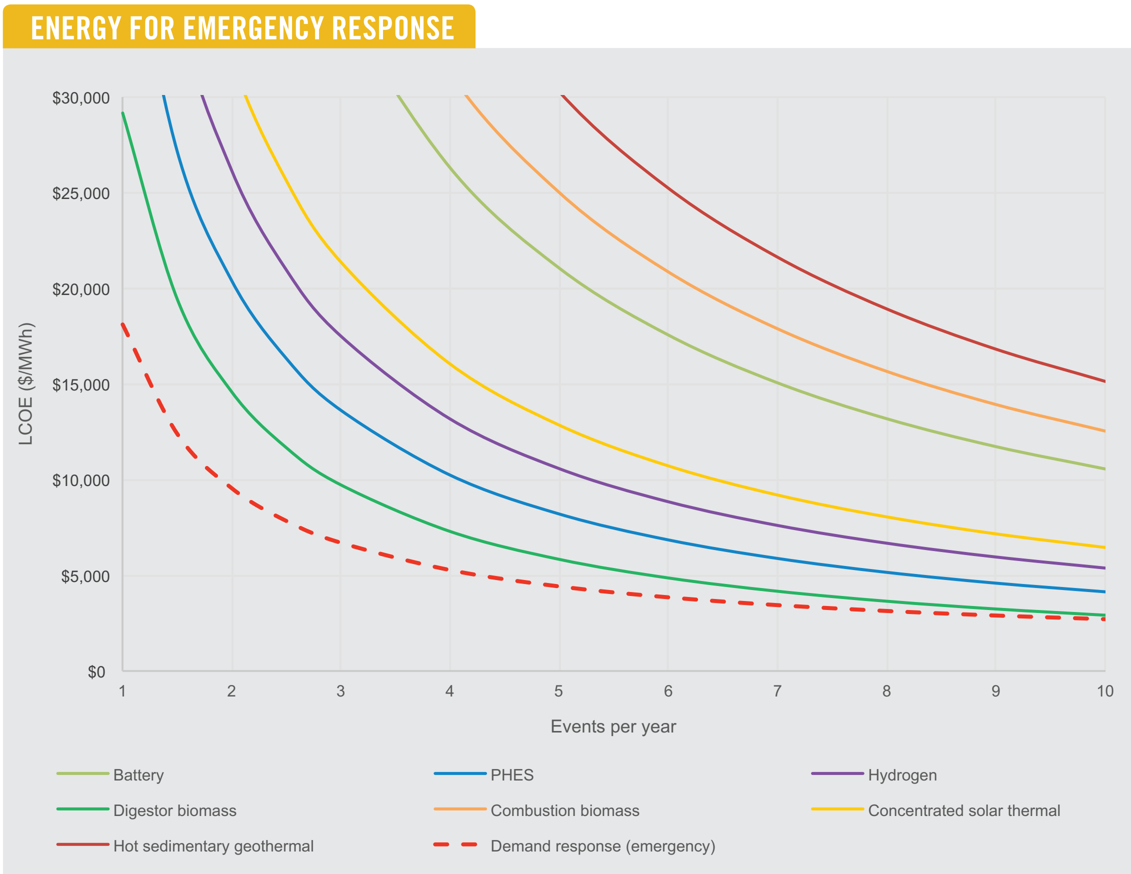


Figure 31: Cost of energy for systems dedicated to 4 hours of operation used for 1 or more discrete events per year

Thus, demand response clearly has potential for short duration use in critical periods, but the cost is dependent on the choice of technology to be used, for instance energy management, onsite generation or storage.

[4] For this analysis the cost of energy input is simply the average cost for the collection technology and the capacity factor is set at the required level rather than resulting from a dispatch strategy applied to a real hourly input trace.

4.7.3. Curtailment of PV or wind

If PV or wind generators are deliberately operated at reduced output using their control systems, they still offer the ability to quickly ramp up output if required by the system, or continue to give a fixed output through small fluctuations in their own input resource level. Given that this study finds the LCOE of dispatchable renewable generation is 1.5 to 2 times that of PV or wind generation on its own, it could be an economically rational approach to achieve a level of dispatchability by holding some wind or PV at up to 50% curtailment to allow up and down dispatchability for specified critical time periods. This would be comparable or complementary to adding short duration battery systems to PV or wind plants for firming.

When multiple PV or wind generators are widely distributed on an electricity network, the volatility of the total net generation is reduced compared to if this generation capacity was centrally located. This reduces the ramp rates imposed upon other generators, likely leading to improved frequency control and potentially lower spinning reserve requirements (which decreases fuel and maintenance costs).

Further advantages arise from the potential to reduce transmission losses by siting generation close to loads (particularly rooftop solar), and specifying modern wind generators and PV inverters to deliver reactive power for voltage support and reduced system losses.

Systems can also be built to better match demand rather than simply maximising daily generation. For example, PV panels could face west rather than north and wind resources could be chosen that are driven by local diurnal temperature cycles rather than large-scale weather patterns. Again noting the cost differential between VRE and dispatchable renewables, such decisions may be cost effective for the system as a whole, though not necessarily for the system owner under current market conditions.

CHAPTER 5
IMPLICATIONS FOR THE FUTURE GENERATION MIX

This analysis has been carried out to improve our understanding and interpretation of dispatchable renewable electricity generation. In this chapter, specific technical outcomes of the study are summarised, followed by a consideration of what the implications might be for the future generation mix. Following on from this, the study has identified what lessons exist for the Australian market and policy settings.

5.1. Technical outcomes from this study

There are multiple commercially available technology options for dispatchable renewable electricity generation for all timescales. Dispatchable renewable energy can provide a mix of immediate firm delivery and strategically dispatchable energy over a range of timescales from minutes to beyond 40 hours for around 1.5 to 2 times the cost of variable generation by wind or PV. In parallel, long-term energy reserves can be added to guarantee generation in critical periods at two to three times the cost of VRE alone.

The modelling found that a variety of technology combinations produced competitive LCOEs that were broadly similar, including PV or wind coupled with pumped hydro, concentrating solar thermal, bioenergy and hot sedimentary aquifer geothermal over longer timescales and wind or PV with batteries for durations of less than one hour.

Specific results include:

General Findings

- There are multiple affordable options for firm dispatchable renewable electricity generation over all timescales at one and a half to two times the cost of variable renewable energy (VRE) when used regularly.
- The dispatchable renewable options of; PV or wind driven batteries, pumped hydro energy storage (PHES) or hydrogen; concentrating solar thermal; bioenergy and geothermal all have a role to play. There is no single winner, and at each timescale there are multiple options that fall within a general least-cost band.
- The likely least-cost future electricity system solution is a mix of both variable and dispatchable renewable technologies, durations and locations with an average cost of electricity considerably lower than dispatchable generation alone.
- Additional, long term energy reserves can be added to a generation system to ensure generation in critical periods at two to three times the cost of VRE alone in critical periods.
- The cost of electricity from dispatchable renewable generation is comparable with estimates for new build gas while avoiding the associated fuel and carbon price risks.
- For a small number of events per year, emergency demand response is more cost effective than a dedicated dispatchable renewable generation option used infrequently.
- A level of short-term firmness could be obtained cost effectively during high VRE generation periods by curtailing and controlling output levels from PV or wind.
- Costs are likely to continue to fall in real terms for all renewable energy technologies in correlation with their growth in global deployment. This will improve the competitive position

of dispatchable renewables compared to gas. The other findings above are likely to remain valid as this occurs.

- Readily achievable growth rates of around 25% per year in dispatchable renewables could keep pace with coal retirements and enable an orderly transition to a large share of renewable energy.

Batteries with wind or PV

- Combining batteries with PV, wind or a grid VRE mix gives LCOE trends that start low and grow quite steeply with increasing amounts of storage. This is a consequence of a high cost per stored energy coefficient but a relatively low output power level related coefficient
- The lowest LCOEs of all battery options occur at a storage level of around half an hour. This illustrates that short duration batteries are particularly suitable to the smoothing of wind and PV electricity generation to reduce ramp rates in the case of sudden changes in resource levels. In comparison to other options, batteries remain in a competitive range out to about three hours of storage.
- The rooftop PV battery case has a higher LCOE than the utility-scale system, due to the non optimal siting and fixed orientation plus not benefiting from the economies of scale that larger utility-scale systems do. However as systems are 'behind-the-meter' they are competitive with retail electricity.
- Battery system deployments have been on a trajectory of 40%/year compound growth and even if that slows to around 30%/year costs should continue to fall.
- The modular nature of battery cells means the cost penalty for small systems is less and, on the flip side, the cost benefit of very large systems is reduced over other technologies.

PHES with wind or PV

- PV, wind and VRE charged PHES offer a competitive and relatively constant LCOE across all durations of storage, it is particularly competitive beyond six hours of storage.
- PHES systems have been widely deployed around the world over many years. This means that the time to a future doubling of installed capacity and likely further cost reduction is much longer than other newer technologies.
- Overall LCOE from PHES will continue to drop as the cost of PV and wind electricity drops even if cost reduction in the PHES technology itself is small.
- Of all the dispatchable technology options PHES is the one that is most site specific and for which costs will vary from site to site, due to its dependence on geology and head height characteristics.

Concentrating solar thermal

- CST systems start to appear competitive from about six hours of installed storage and upwards. The higher LCOEs for short durations of storage reflect the relatively high installed cost of power related components, while the drop to lower values for longer durations reflects the low cost per stored energy of the molten salt system.

- There is a minimum in LCOE in the range of 15 to 20 hours of storage, however systems with less storage may be preferred to target generation in peak periods.
- CST with molten salt storage has only been applied commercially since 2006. Since then it has shown an average compound growth rate of deployment around 40%/year, although this is very dependent on the policy settings of the countries that have deployed it. Whilst this growth rate has slowed, the likelihood of cost reduction remains high.

Hydrogen with wind or PV

- Hydrogen-based systems combined with wind or PV do not appear competitive over the zero to 40-hour timescale at current costs.
- Although hydrogen-based LCOEs are high, it is notable that hydrogen is the only technology option for which costs are still trending downward at 40 hours of storage.
- Hydrogen systems are now at a point in their commercial development where they are commercially available at scale, but it is too soon to draw any significant conclusions on the likely rate of deployment and cost reduction.
- As wind and solar electricity come down in cost, the impact of low efficiency of energy storage becomes increasingly less important. This will contribute to LCOE reduction irrespective of cost and performance improvements in the hydrogen technologies.
- Hydrogen has the lowest cost per MWh of storage capacity of any option other than biomass.
- There is potential to lower LCOE by making use of existing gas pipelines and gas turbine systems in hybrid mode.

Bioenergy

- Anaerobic digestion systems operating on zero cost waste and operating at 50% or more capacity factor are the cheapest dispatchable renewable generating option considered. Combustion-based bioenergy generation is also very competitive at 50% or more capacity factor, as long as low cost biomass inputs can be sourced.
- Biomass combustion systems typically store fuel in reserve for multiple days of operation. This is the cheapest form of stored energy available. Ensuring such systems can operate year-round as dispatchable power only requires extending the fuel storage to whatever time period is sought..
- The contribution of bioenergy to the generation mix is limited by the availability of waste or low cost feedstock. Future systems should be configured to run flexibly with reduced capacity factors to gain the greatest benefit.
- The bioenergy technologies analysed are mature, with modest growth in global deployment. Cost reduction potential for bioenergy options appears most likely to come from improvements in the harvesting, transport, and processing of biomass fuels.

Geothermal

- Australia does have some hot sedimentary aquifer resources. Power generation based on these appears to be cost effective and could be operated in a flexible manner to help balance VRE.
- Engineered Geothermal systems were subject to high expectations in previous years. Based on cost estimates available, they do offer the potential of reasonably competitive dispatchable generation if operated continuously.

5.2. Cost vs value

This study has focused on analysing the cost and performance of selected mature dispatchable renewable energy generation options. It was not in the scope of the study to analyse the exact income or monetisable value that could be achieved either at present or into the future. Nonetheless some observations can be made.

A dispatchable renewable electricity generator would produce value from various sources that may or may not be fully realisable as income to its owner either now or in the future. Key sources include:

- **Generation of electricity that can be dispatched in the wholesale energy market**:

    Depending on the system and dispatch strategy, values higher than the average spot price would be achievable.

- **Generation of electricity that is renewable and hence free of GHG emissions:**

    For systems commissioned prior to 2030, LGCs would be produced, however any LGC value expires in 2030 and the value of LGCs post 2020 is highly uncertain. A longer-term market value may be associated with low emissions generation under a future emissions policy such as the National Energy Guarantee.

- **Provision of ancillary services:**

    The average market value of ancillary services for existing dispatchable generators is only a small fraction of that which can be derived from energy sales. It will likely remain less than 5-10% of energy sales for dispatchable renewable generators also.

- **Potential network support:**

    A combination of firm capacity and distributed location of generation sources can alleviate the need for network upgrades, however market rules currently do not facilitate this being fully monetised.

In addition to these, there is a further aspect that could be called ‘option value’ for society. Energy systems constructed at an early stage of commercial development help to build investor confidence in the technology and supply chain capability. This provides potential future cost reductions and enhanced optionality for future investors that is hard to quantify. To an energy system developer, it is a value that can only be monetised if it grows the developer’s market or competitive positioning and this can be a high-risk proposition. Public good spillovers can be valued by government through RD&D support initiatives.

Table 20: Evolution of annual average wholesale electricity prices in the NEM

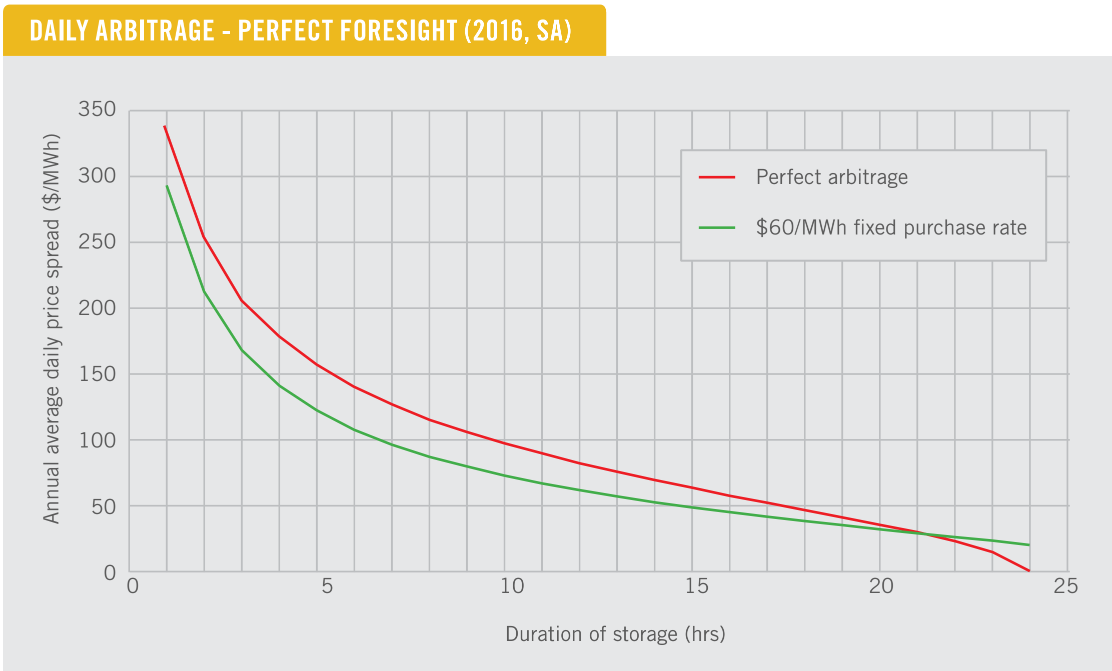
Financial year	Queensland ($/MWh)	New South Wales ($/MWh)	Victoria ($/MWh)	South Australia ($/MWh)	Tasmania ($/MWh)
2009-10	37	52	42	83	30
2010-11	34	43	29	42	31
2011-12	30	31	28	32	33
2012-13	70	56	61	74	49
2013-14	61	53	54	68	42
2014-15	61	36	32	42	37
2015-16	64	54	50	67	97
2016-17	103	88	70	123	76

Determining income value on a historical basis is very specific to the renewable generator technology combination chosen. Trying to predict these for the future is extremely difficult given the unknown market settings, changes in demand and mix of competing generators and characteristics in the future.

Table 20 illustrates the evolution of average wholesale prices in the NEM[5] over the past decade. It is apparent that prices have increased considerably since 2010 and are currently around $100/MWh with significant variation between states. By itself this is somewhat lower than the LCOEs predicted for any of the dispatchable renewable generation options analysed with the exception of an AD gas system run continuously.

A dispatchable generator would be expected to earn somewhat more than the average if it is preferentially operated at times of higher price, depending on configuration. To provide some insights into this some analysis of the potential for price arbitrage in the NEM has been carried out (see Appendix D). Figure 32 shows results for analysis of perfect foresight price arbitrage with daily cycles and assumed 100% efficiency. It shows the price differential as a function of hours of stored energy for two cases: a storage system that charges and discharges at times that maximise the differential (red curve), and a dispatchable generator that has a fixed cost for input energy ($60/MWh$_e$ is assumed in this case) and sells in periods that maximise revenue (green curve).

[5] https://www.aer.gov.au/wholesale-markets/wholesale-statistics/annual-volume-weighted-average-spot-prices



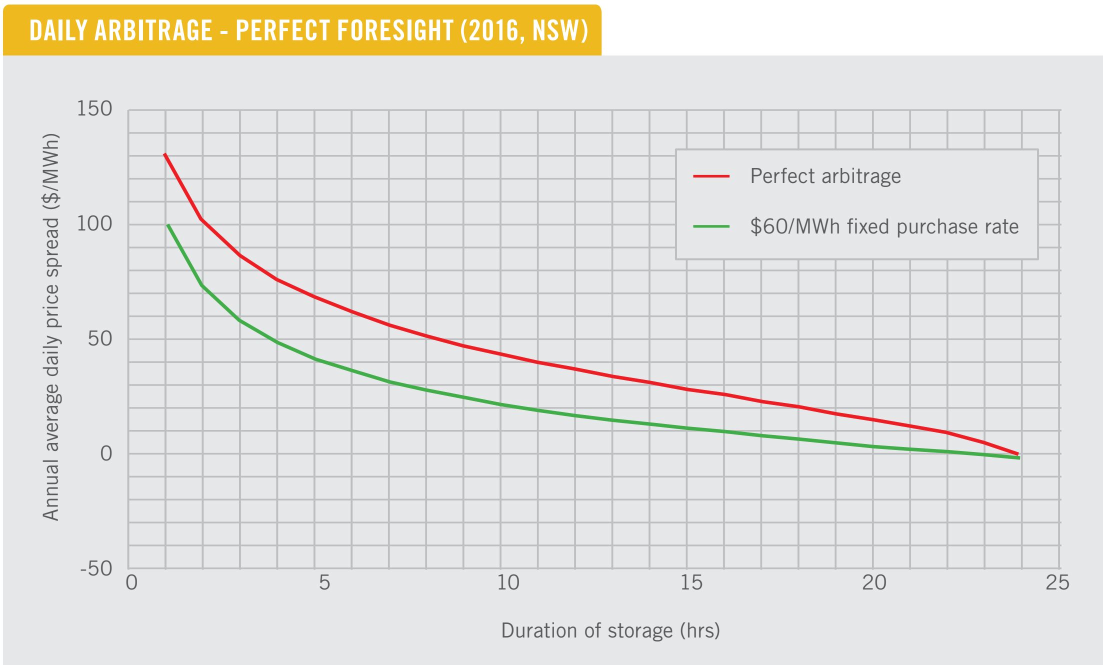


Figure 32: Average price spread for perfect foresight price arbitrage as a function of duration of storage

For the case of an electricity storage system in isolation, the red curves indicate that this differential is a maximum at low durations of storage that declines to zero as 24 hours of storage is approached. However the low durations also mean that the volume of energy bought and sold is reduced.
For a particular energy storage technology, the choice of duration to maximise profitability will be determined by the relative cost contribution from power related cost components compared to the cost contribution that is related to the volume of stored energy.

For a dispatchable generator, again the maximum differential comes with the lowest duration hours, but such a system will process a smaller volume of energy. The wholesale market revenue for such a system would be $60/MWh plus the differential calculated. This with, for example, five hours of storage in South Australia in 2016 would have been around $180/MWh, and $100/MWh in NSW for the same year. Both numbers are considerably higher than the annual average wholesale prices in that year. However these numbers provide some indication of the revenue levels that a dispatchable renewable generator could have accessed for that fraction of its energy that was strategically dispatchable. The remaining energy would earn more or less than the wholesale market average depending on its natural correlation of timing with price variations.

At present the main mechanism for rewarding zero emissions generation is the Renewable Energy Target. LGC spot prices have averaged around $82/MWh through 2017[6], however in previous years they have been much lower. From 2020 through to the scheme's end in 2030 the annual target will no longer increase and as more renewable generators come on line during that period, the value of LGCs is expected to drop rapidly to low levels. Other new policy initiatives may transpire over this period that provide monetisable value for renewable generation.

As noted above, the value of ancillary services might be expected to contribute around 5% of a wholesale energy market income stream. Regarding the potential value from network support opportunities, ISF have previously studied the potential network benefits of suitably located firm generation[7] (Rutovitz et al., 2013) ,. They found that the hypothetical value of a network support payment to avoid network investments at identified constrained locations in the NEM would be $15/MWh on average but in specific locations was found to be up to $134/MWh. Current market rules however limit the extent to which this can be monetised.

Attempting to identify a societal option value is very difficult. However, if it is assumed that at some point Australia will move towards zero emissions, acting early with dispatchable renewable generation reduces the risk of sudden disruptions to the market from large numbers of coal-fired generator closures within a short period. Ensuring an 'orderly transition' clearly has significant value.

Given this study has found that dispatchable renewable electricity at 2017 costs could be generated at between $100/MWh and $130/MWh, it would appear that at the present time the overall value could be attributed to such a generator would exceed its cost of energy. However, if wholesale and LGC prices were to revert to prices of just a few years ago this would no longer be the case. At the current time, predicting future income streams is particularly uncertain.

To finance dispatchable renewable generators some form of income certainty is required to sufficiently justify the investment. This is seen for wind and PV developments in the form of PPAs or other offtake agreements, typically from electricity retailers. In taking on the future income risk, offtakers apply a considerable discount to the best estimate of merchant market return. Thus published wind or PV PPA prices are seen to be much less than the current sum of wholesale and LGC spot price income. In fact, they correlate closely with the wind and PV LCOEs calculated in this study. For large-scale development of dispatchable renewable generation, offtake agreements will be

[6] http://greenmarkets.com.au/resources/lgc-market-prices
[7] http://breakingthesolargridlock.net/documents/Breakingthesolargridlock_finalv2.pdf

needed at a level commensurate with the LCOEs analysed. These will need to be driven by offtakers' assessments that future monetisable values will average higher levels than this for the long term.

5.3. Evolution of the generation mix

Given that wind and solar PV are already the lowest cost new generation technologies in many locations around Australia and that their costs continue to decrease, it is clear that the share of VRE in the electricity energy mix will continue to increase. A key issue for system planners is to ensure that electricity consumers can continue to receive reliable power. The requirement for reliability is part of the 'energy trilemma' (World Energy Council, 2017), which involves the balance between energy affordability, sustainability and security. For some years Australia has ranked around 33 out of 125 countries on a global measure of the 'trilemma'.

At present in the NEM, dispatchable capabilities are provided for the most part by fossil fuelled thermal power supplemented by the Snowy and Tasmanian hydroelectric schemes. However existing coal-fired power stations are reaching the end of their economic life. In 2014, 29% of Australia's 24 coal fired power stations were over 40 years old (Climate Council of Australia, 2014). This was expected to increase to 45% by 2020 and 65% by 2030, unless plants were retired[8]. In choosing technologies to replace these ageing stations, excluding nuclear power[9], the choices are between new coal units, gas-fuelled units or dispatchable renewable technology, but also between different methods of achieving short, medium and long-term system reliability requirements.

In considering how future demand will be met on a day to day basis, it is becoming widely accepted that lower cost VRE will be the first level of the dispatch stack rather than traditional coal-fired generators[10]. The analysis carried out for this study confirms that around half to one hour duration battery storage is the most cost-effective way of providing immediate VRE firming. A range of options have been identified to extend firm generation beyond the peaks in available resource. Finally, the remaining deficit could be filled with the strategically dispatchable high-value energy that has the greatest freedom in delivery times. Figure 32 illustrates how a future least-cost mix may be put together to meet a daily load profile.

[8] Since then, Hazelwood has already closed and Liddell is scheduled to close in 2022.
[9] Although Australia has nuclear fuel resources, it does not have an established nuclear power supply chain. This would take many years and significant investment to establish and does not currently have a social licence. Current costs of nuclear power internationally are significantly higher than the fossil fuel and renewable options modelled here while, like coal, nuclear plants are better suited to operate at constant output and high capacity factor. This means that they would not solve the current problems faced in the Australian grid.
[10] Although for sufficient VRE penetration there may be times when coal may bid negative due to the need to keep plant operating for OPEX and to meet frequency control obligations.

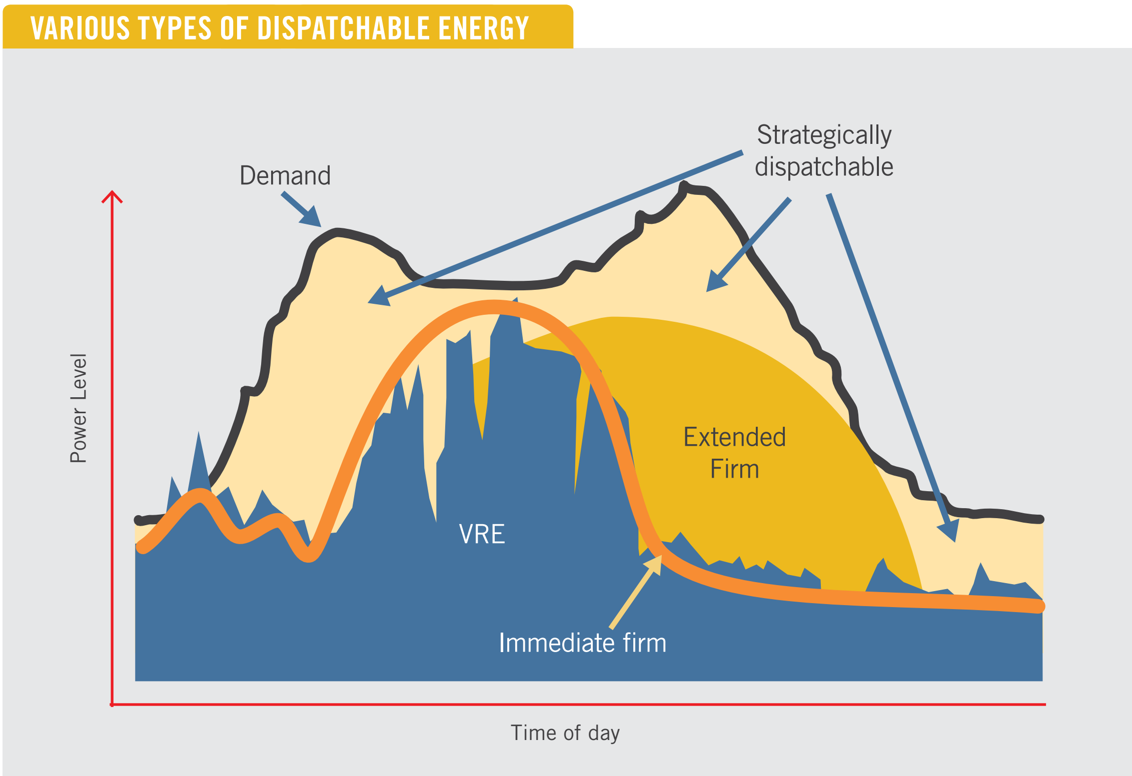


Figure 33: Illustrative use of various types of dispatchable renewable generation in combination with VRE to provide flexible and dispatchable renewable energy-based electricity to meet a daily load

This study was designed to compare the cost of individual dispatchable renewable technologies. It is important to emphasise that this cost is explicitly not the average cost of electricity of a 'system' or grid with 100% renewable energy. Instead the study is focussed on the individual cost of a dispatchable engine such as pumped hydro, battery, or hydrogen, together with a dedicated renewable collector such as a wind or solar farm or an inherently dispatchable thermal turbine supplied by concentrating solar or bioenergy. The overall electricity cost for a balanced grid would therefore be the average cost of its total VRE sources plus the required level of firm dispatchable generation together with amortisations of any extra investments in network assets and other enabling aspects. Because of portfolio diversification effects the LCOE of a 100% renewable grid is almost certainly going to be lower than the cost of an individual dedicated dispatchable generator.

Detailed grid integration studies are needed to estimate the optimum mix of VRE, firm, flexible and dispatchable capacity, as well as how to transition from today's mix to the future. A mix of technologies, configurations and geographical locations is likely to minimise the overall cost due to the smoothing effect of different VRE generators delivering energy at different times..

Noting that this investigation has assessed the 2017 LCOE of VRE at around $65/MWh and the LCOE of firm dispatchable RE at between $90/MWh and $140/MWh over the range of timescales, the average overall cost of supplying a mix of variable and dispatchable renewable electricity would fall in the range $65 to $140/MWh, depending on the fraction of dispatchable RE that is included.

This is illustrated in Figure 34. The increment in cost over the lower VRE LCOE would represent the 'levelised cost of balancing' that is discussed in other studies[11]. So, for example, the addition of 30% of dispatchable renewable energy to a given capacity of VRE would take the average LCOE from $65/MWh to around $80MWh.

Recent studies are showing that the levels of storage or dispatchability required to maintain system security and reliability of supply are much smaller than had been previously suggested for the levels of VRE expected up to 2030 (see for instance studies reviewed in Appendix A). This study further suggests that the cost increment for RE dispatchability is not exorbitant and is of the same order as historical daily variations in the wholesale price from off peak to peak periods. Thus, depending on market settings, it is entirely possible that the level of dispatchable renewable generation built by investors in response to energy market signals could exceed the minimum requirements to maintain reliability of supply.

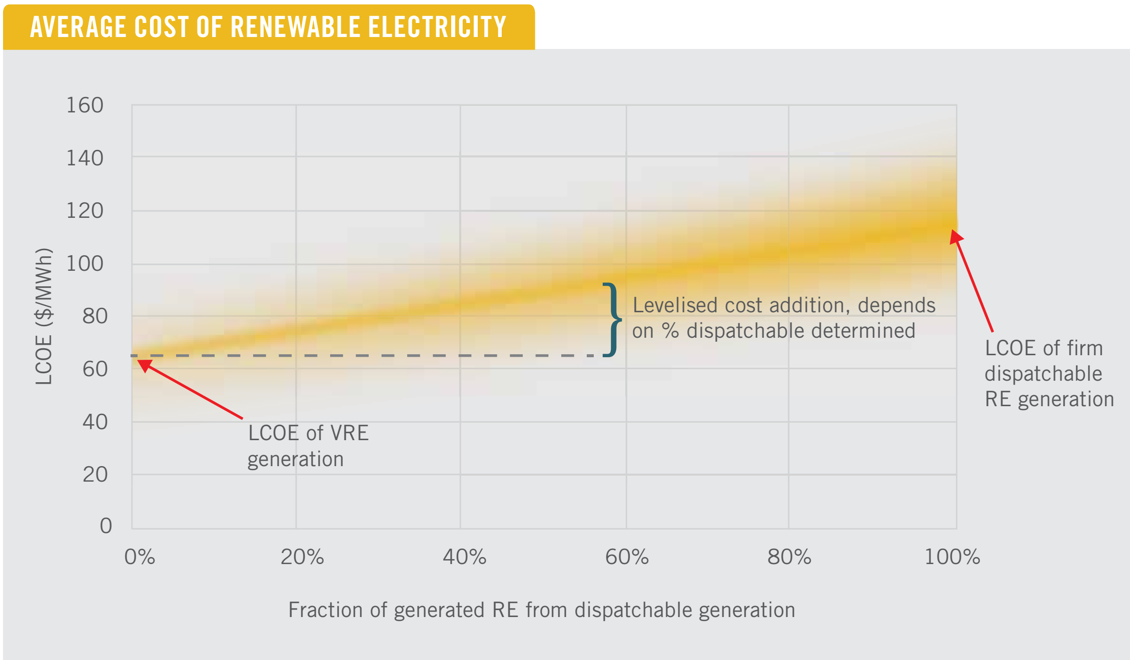


Figure 34: The average LCOE of increasing the dispatchable fraction of individual renewable energy generators (note this is not the fraction of RE in the grid as a whole)

In a bigger picture view, a key motivation to pursue dispatchable renewable generation is the consequence of the national and global commitment to the Paris climate goals, which implicitly suggests that the electricity sector should be net zero emissions by 2050. To place this in context, Australia currently has around 200 MW of 'new' dispatchable renewable capability and the likelihood of several hundred more megawatts in operation by 2020. Figure 35 illustrates the level of capacity that can be achieved over time if a range of realistically possible growth rates were maintained. It suggests that a minimum growth rate of around 20% per year would reach the likely magnitude

[11] Balancing costs are sometimes taken to include the cost of any network upgrades and extensions that may be required also.

needed by 2050. It would also keep pace with likely coal plant retirements and so ensure an orderly transition.

The primary driver of LCOE for renewable energy systems is capital cost and the cost of capital to meet that cost. As is usual with studies of this kind, far more focus has been placed on the capital cost than the cost of capital. This study has assumed that all technologies have the same risk profile, which clearly is not the case at the present time, as well as an 'overnight' capital cost. That is, no adjustment has been made for the fact that some technologies, e.g. batteries, can be bought off the shelf and installed within three months whereas others e.g. pumped hydro, face construction periods measured in years even after often arduous environmental approvals have been obtained. In a competitive market, speed of deployment and development risks would influence the actual choice of dispatchable technology as well as the opportunity for other sources of revenue, such as by providing system security services.

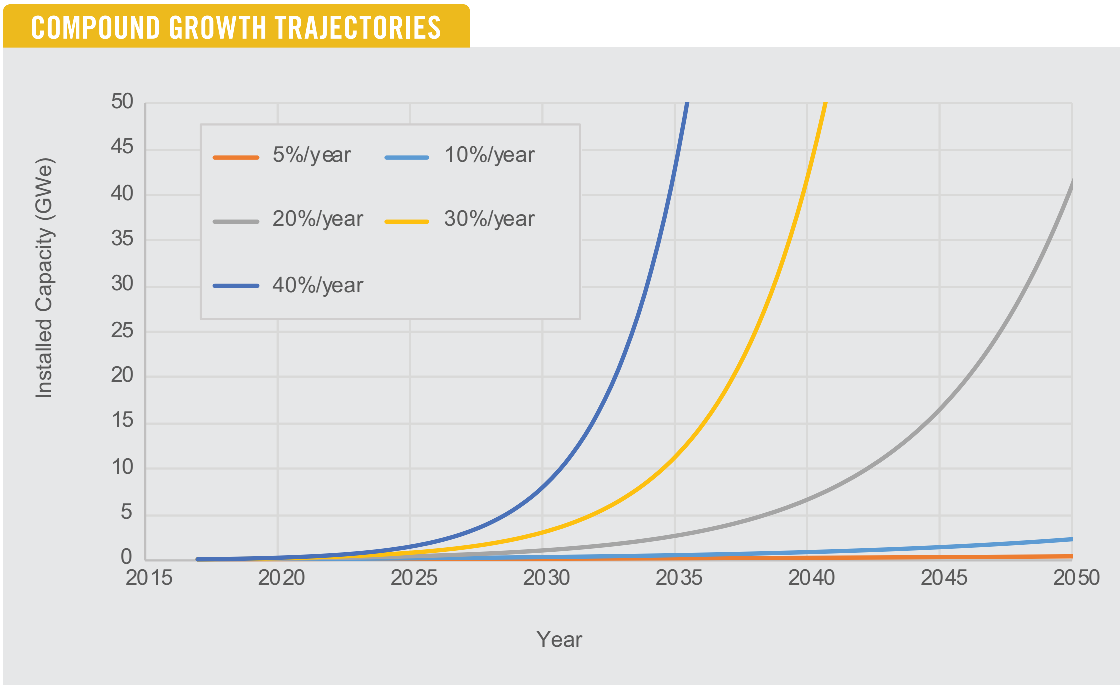


Figure 35: Generic compound growth trajectories of a portfolio of dispatchable RE technology starting from 200 MW in 2017

From the point of view of the system operator and the electricity consumer, the issue is to ensure that there is sufficient dispatchable generation capacity. A reasonable perspective is that, over the next 20 years, perhaps 5-10 GW of dispatchable capacity needs to be built. This study shows that there are a variety of technologies that can do the job.

5.4. Lessons for Australian market and policy initiatives

It is clear that the cost of dispatchable renewable generation is likely to come down due to three drivers:

- The size scale factor, which measures the change in unit cost for an increase in system size. Systems with storage have two scale factors, one for power and one for energy.
- The learning rate, which measures the change in cost for a doubling of installed product. Based on available data, the study used a constant learning rate of 15% for all the technologies which, going forward, may be high for some technologies and low for others.
- The deployment rate, which determines how long it takes to double installed capacity. Rates between 40%/year and 5%/year have been encountered historically for the relevant technologies and these are strongly linked to the market and policy signals they face.

However there has to be deployment for these drivers to have an impact. Industry consultations undertaken for this study suggest that neither renewable generation developers nor firming developers can currently see a sufficient long-term market signal to make the necessary investment in dispatchable renewable generation that would produce an ongoing deployment pipeline without assistance from government.

Dispatchable renewable generation is a complex value proposition with the relative value of energy storage to customers, networks, retailers, and the system operator changing with network, load, and supply conditions. Therefore, the alignment of energy storage value has a complex time-varying component. Designing regulatory and policy frameworks to encourage efficient investment without stifling future innovations will likewise be a complex task. Appendix E reviews a range of policy measures to advance dispatchable renewable generation that have been tested around the world.

CHAPTER 6
CONCLUSION

Various combinations of commercially available technology have been reviewed in regard to their development status, performance characteristics, capabilities and cost. Data has been assembled both from reviewed literature and from consultations with relevant stakeholders (which in some cases were commercial in confidence).

An installed cost model has been developed for each technology combination, using a power law fit to size and a cost factor based on either power capacity or stored energy capacity as appropriate. Notwithstanding the limitations posed by assessing each technology combination in isolation, this approach to cost modelling now allows for analyses in which the various combinations can be sized in different configurations to target operation between short duration and continuous, whilst optimising the cost effectiveness.

The analysis of the cost of firm energy from dispatchable renewable energy generation shows that it is comparable to new build fossil-fired generation and that there are multiple options at any given duration of generation or storage with no clear winners.

It is clear that a range of proven and affordable options is available to more than adequately cater for significantly increased levels of renewable energy in the Australian electricity mix, and for an eventual net zero emission technology mix by 2050 as implicitly required by the longer-term goals of the Paris accord.

At a time when there is much debate on the direction of future energy policy and the extent to which the system is, or will become, vulnerable to weaknesses in reliability or security, the importance of this study is to show that an orderly transition to a low emissions future is readily achievable and affordable.

For ARENA, this study can help inform its ongoing investment priorities. All the options studied are potentially commercially available at scale. However, there is not a great deal of recent Australian experience, thus investments that support early deployments in this country will help to build local capabilities and community and industry confidence. Depending on policy developments in the near future, it is still the case that commercial deployments of these dispatchable renewable options cannot monetise sufficient long-term value to be financeable on an unsubsidised basis. ARENA can help bridge these gaps.

All technologies may benefit from investments in R&D that help to further lower the cost of energy. Hydrogen systems could be singled out for special attention in this regard. On the analysis carried out in this study hydrogen does appear uncompetitive with the other options, however this is very closely linked to efficiency issues that could be addressed by R&D efforts. If successful, then a very cost-effective approach to storing energy could be unlocked.

For Australia, and hence for ARENA's investment priorities, pursuing a range of dispatchable renewable energy options and developing a framework that can readily accept new technologies as they are developed will minimise the cost of ensuring dispatchability and maximise the chance of building a reliable, affordable and sustainable energy system for the future.

LIST OF ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESO	Alberta Energy System Operator
AETA	Australian Energy Technology Assessment
AGC	automatic generation control
ANU	Australian National University
ARENA	Australian Renewable Energy Agency
ASEFS	Australian Solar Energy Forecasting System
AUD	Australian dollar
AWEFS	Australian Wind Energy Forecasting System
BREE	Bureau of Resources and Energy Economics
CAGR	Compound annual growth rate
COP 21	Conference of the Parties 21 (Climate change negotiations)
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrating solar power (see also CST)
CST	Concentrating solar thermal (see also CSP)
DEWA	Dubai Energy and Water Authority
DR	Demand response
EGS	Engineered geothermal system
EMMS	Electricity Market Management System
EOI	Expression of interest
EPC	Engineering, procurement and construction
EPRI	Electric Power Research Institute
ERCOT	Texas electricity system operator
FCAS	Frequency control ancillary services
GHG	Greenhouse gases
GIS	Geographic information systems
HHV	Higher heating value
HTF	Heat transfer fluid
HSA	Hot sedimentary aquifer
IEA	International Energy Agency
ISF	Institute for Sustainable Futures
ITP	ITP Renewables and ITP Thermal
kW	Kilowatt, unit of power – subscript e for electric, t for thermal
kWh	Kilowatt-hour, unit of energy (1 kW generated/used for 1 hour)
LCOE	Levelised cost of energy
LGC	Large-scale Generation Certificate (1 MWh)

LHV	Lower heating value
LSS	Large-scale solar
LSSi	Load Shed Service for Imports (Alberta)
MEI	Melbourne Energy Institute
MW	Megawatt, unit of power = 1000kW – subscript e for electric, t for thermal
MWh	Megawatt hour
NCAS	Network Control Ancillary Services
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
PHES	Pumped hydro energy storage
PPA	Power price agreement
PR	Progress ratio
PV	Photovoltaic
R&D	Research and development
RD&D	Research, development and deployment
RE	Renewable energy (electricity)
RERT	Reliability and emergency trader mechanism (of AEMO)
RET	Renewable Energy Target
SCADA	Supervisory control and data acquisition
SHV	Strategic high value
UOL	Use or lose
USD	US dollar
VRE	Variable renewable energy
WACC	Weighted average cost of capital

GLOSSARY

When the security and reliability of electricity systems are discussed in reports and public commentary, various terms are used to describe the characteristics of an electricity system. Certain terms have an electrical engineering definition specific to the electricity sector, and some terms are also general-use terms that have a possibly ambiguous meaning because they are also used in the common English language. This glossary provides definitions of commonly used terms in the power and storage sectors, and a selection of definitions from Australia's National Electricity Rules.

The National Electricity Rules govern the operation of Australia's National Electricity Market (NEM) and are made under the National Electricity Law (Australian Energy Market Commission (AEMC), 2018). Many of the definitions are legalistic in nature and concerned with the minutiae of the NEM operation. They do however include a number of particularly useful definitions that impact on the scope covered by this study. That subset is reproduced here, with definitions derived from the National Electricity Rules.

Availability: The percentage of time that a generator is available to generate electricity. Availability is affected by regular maintenance and plant breakdowns. Variable renewable generators may have lower capacity factors, but can have very high availability factors.

Available capacity: The total MW capacity available for dispatch by a scheduled generating unit, semi-scheduled generating unit or scheduled load (i.e. maximum plant availability) or, in relation to a specified price band, the MW capacity within that price band available for dispatch (i.e. availability at each price band). *(National Electricity Rules definition)*

Baseload: The minimum load (MW) over a specified period, typically a year. In Australia, this portion of the load was traditionally met using coal fired generation running at a largely constant level that, until recently, had the lowest fuel and operating cost with capital costs amortised over long periods. Baseload generators are typically operated at a constant load and a high capacity factor.

Black start capability: A capability that allows a generating unit, following its disconnection from the power system, to be able to deliver electricity to either (a) its connection point or (b) a suitable point in the network from which supply can be made available to other generating units without taking supply from any part of the power system following disconnection. *(National Electricity Rules definition)*

Black system: The absence of voltage on all or a significant part of the transmission system or within a region during a major supply disruption affecting a significant number of customers. *(National Electricity Rules definition)*

Capacity: Power rating of a generator (MW) under standard, documented conditions. Often this is used to mean 'design point' or 'nameplate' capacity, however maximum capacity can sometimes be slightly higher than this. There can also be a distinction between gross and net capacity according to whether internal loads have been subtracted (net) or not (gross).

Capacity factor: Ratio of average power output over nameplate capacity for a specified time period, typically a year. Resource availability influences VRE generation capacity factors.

Capacity reserve: At any time, the amount of surplus or unused generating capacity indicated by the relevant generators as being available in the relevant timeframe minus the capacity requirement to meet the current forecast load demand, taking into account the known or historical levels of demand management. *(National Electricity Rules definition)*

Central dispatch: The process managed by AEMO for the dispatch of scheduled generating units, semi-scheduled generating units, scheduled loads, scheduled network services and market ancillary services in accordance with rule 3.8. *(National Electricity Rules definition)*

Constrained off/on: In respect of a generating unit, the state where, due to a constraint on a network, the output of that generating unit is limited below/above the level to which it would otherwise have been dispatched by AEMO on the basis of its dispatch offer. *(National Electricity Rules definition)*

Contingency capacity reserve: Actual active and reactive energy capacity, interruptible load arrangements and other arrangements organised to be available to be utilised on the actual occurrence of one or more contingency events to allow the restoration and maintenance of power system security. *(National Electricity Rules definition)*

Cycle life: The number of charge/discharge cycles an energy storage system or technology can deliver in its lifetime.

Discharge time: The period of time (seconds, minutes, hours, days) over which a storage system or technology can release its stored energy.

Dispatch: The act of initiating or enabling all or part of the response specified in a dispatch bid, dispatch offer or market ancillary service offer in respect of a scheduled generating unit, semi-scheduled generating unit, a scheduled load, a scheduled network service, an ancillary service generating unit or an ancillary service load in accordance with rule 3.8, or a direction or operation of capacity the subject of a reserve contract or an instruction under an ancillary services agreement as appropriate. *(National Electricity Rules definition)*

Dispatchable: A power plant or load that can vary its output (up or down) at the command of the plant operator or system operator. There are different kinds of dispatchability that are often provided by different technologies. Most commonly, dispatchability refers to the five-minute dispatch cycle of the National Electricity Market (see Scheduled), but it can also refer to frequency response ancillary services that respond in seconds, and it may soon include inertial services that respond in milliseconds. Various technological approaches will have different characteristic ramp rates and start up times and so play different roles.

Electrochemical energy storage: Energy storage that uses a reversible chemical reaction to store electricity. The storage technology benefits from the fact that both electrical and chemical energy share the same carrier: the electron. Electrochemical energy storage technology is commonly called battery energy storage.

Energy constraint: A limitation on the ability of a generating unit or group of generating units to generate active power due to restrictions in the availability of fuel or other necessary expendable resources such as, but not limited to, gas, coal, or water for operating turbines or for cooling. *(National Electricity Rules definition)*

Firm capacity: The minimum power output (MW) expected from a generator with high confidence over a specified period. Firming refers to the adding of firm capacity.

Flexibility: "The ability of a power system to respond to change in demand and supply" (21st Century Partnership). Flexibility can be achieved on both the supply side and the demand side. Supply side options include generators with operating characteristics such as fast ramping, fast starting and low minimum operating levels, existing storage such as large hydro, curtailment of VRE generation and new storage such as batteries.

Intermittent: Literally "occurring occasionally or at regular or irregular intervals; periodic" (Collins dictionary). Arguably this is not an appropriate description for renewable energy technologies such as PV and wind as it implies unpredictable switching between some generation and less or no generation. Using appropriate data and methods, many of which are already applied in Australia, changes in renewable generation output are generally predictable. Therefore, variable is a more accurate term. The National Electricity Rules do however define PV and wind as intermittent, something which could be worthy of revision: "Intermittent: A description of a generating unit whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro generators without any material storage capability." *(National Electricity Rules definition)*

Lower/raise service: The service of providing, in accordance with the market ancillary service specification, the capability of controlling the level of generation or load associated with a particular facility in response to a change in the frequency of the power system beyond a threshold or in accordance with electronic signals from AEMO in order to lower/raise that frequency to within the normal operating frequency band. There are categories for 'delayed' and 'fast' services. *(National Electricity Rules definition)*

Peak load: The maximum load (MW) over a specified period such as a day or year. In Australia, annual peak loads typically occur on hot days and the extra load is met using gas-fired generators. Open cycle gas turbines have relatively low capital costs, though fuel and operating costs can be high. Peak load generators are typically operated at low capacity factors.

Penetration (of renewable or other generation): The instantaneous renewable power (MW) divided by the total load (MW). Not to be confused with renewable total annual contribution which is the annual MWh generated by renewable generation divided by the annual load (MWh).

Plant availability: The active power capability of a generating unit (MW), based on the availability of its electrical power conversion process and assuming no fuel supply limitations on the energy available for input to that electrical power conversion process. *(National Electricity Rules definition)*

Power system security: The safe scheduling, operation and control of the power system on a continuous basis in accordance with the principles set out in clause 4.2.6 *(National Electricity Rules definition)*

Ramp rate: The rate of change of active power (expressed as MW/minute) required for dispatch. *(National Electricity Rules definition*). Further to this, the maximum ramp rate is: The maximum ramp rate that an item of equipment is capable of achieving in normal circumstances. This may be (a) as specified by the manufacturer or (b) as independently certified from time to time to reflect changes in the physical capabilities of the equipment. *(National Electricity Rules definition)*

Reliability: The probability of a system, device, plant or equipment performing its function adequately for the period of time intended, under the operating conditions encountered. *(National Electricity Rules definition)*. A plant may have high reliability, but lower availability due to the requirement for long maintenance activities. The term can also be used at the network or system level as a measure of capacity to meet all consumer demand. All forms of power generation are subject to unexpected breakdown and the electricity system is required to have redundancy to allow for reasonable failure scenarios. Currently the term is particularly being used in discussions of the electricity system as a whole.

Round trip efficiency (of storage): The overall efficiency of charging the energy store with electricity, storing the energy and then discharging it at a later stage. Note the rate of discharge can affect efficiency, e.g. a 1 MW, 4 MWh (usable capacity) battery will have different round-trip efficiencies if it is discharged over 4 hours or 8 hours.

Scheduled: A generator with an aggregate nameplate capacity of 30 MW or more is usually classified by AEMO as scheduled, which means that it is directed to produce a specified output in each dispatch interval. Conversely, generators under 30 MW are classified as non-scheduled and do not participate in central dispatch. VRE generation is generally classified as semi-scheduled which means that AEMO may direct the generator at times, but they otherwise run at the maximum output possible under current resource (e.g. wind or sun) conditions.

Security: A measure of the stability of the power system and its capacity to continue operating within defined technical limits even in the event of sudden changes such as a loss of a generator or interconnector. In a sense system security is a more critical subset of contributors to system reliability.

Sent out generation: In relation to a generating unit, the amount of electricity supplied to the transmission or distribution network at its connection point. *(National Electricity Rules definition)*

Specific energy or energy density (of storage): (Watt hours/kg): The amount of energy that can be stored per unit weight.

Synchronous generating unit: The alternating current (AC) generators of most thermal and hydro (water) driven power turbines that operate at the equivalent speed of the frequency of the power system in its satisfactory operating state. *(National Electricity Rules definition)*

Unserved energy: The amount of energy demanded, but not supplied, in a region determined in accordance with clause 3.9.3C(b), expressed as (a) GWh or (b) a percentage of the total energy demanded in that region over a specific period of time such as a financial year. *(National Electricity Rules definition)*

Variable renewable energy: "Something that is variable changes quite often" (Collins dictionary). PV and wind electricity generation are variable but also predictable. Variable Renewable Energy (VRE) is thus the term used to refer to the mixture of wind and PV generation.

Volumetric energy density (Watt hours/litre): The amount of energy that can be stored per unit volume in a storage system or technology.

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APPENDICES

APPENDIX A. GENERAL LITERATURE REVIEW

This study builds on extensive past analysis related to the subject. The following sections provide brief reviews of selected general studies, while other technology specific literature is discussed in context in other chapters as relevant.

A.1. Finkel, Independent Review into the Future Security of the National Electricity Market

The most recent wide-ranging review of the Australian National Energy Markets, the Finkel Review (Finkel *et al.*, 2017) identified that there has been a reduction in the proportion of dispatchable capacity in the NEM due to the retirement of coal fired generation without a corresponding investment in new dispatchable capacity. The Review defines dispatchable capacity as capacity that can respond to electricity demand on call, and can be provided by a range of demand and supply sources. These include generation from coal, gas, hydro, solar thermal, and biomass plant, interconnectors, storage and demand response mechanisms.

The Review considered declining levels of dispatchable capacity as an issue affecting system security and reliability. It recommended that new generation projects should be required to bring forward new dispatchable capacity to regions where levels of dispatchable capacity have fallen below minimum levels set by the AEMC and AEMO (Generator Reliability Obligation).

The Review implied that dispatchable capacity could be met using a variety of technologies or partnership approaches, and that this should be:

- expressed in terms of percentage of the variable renewable energy nameplate capacity
- able to be dispatched for a required time period
- not necessarily located onsite and able to capitalise on project economies (e.g. multiple variable RE projects could pair with large-scale battery or gas-fired generation).

The Review also considered the cost of variable renewable energy with firming using gas. According to information provided by AGL to the Review, new build wind supported by gas peaking generation would be cheaper than new CCGT plant at a gas price of \$8/GJ and new build solar PV supported by gas peaking generation would be cheaper than new CCGT at a gas price of \$12/GJ.

Thus the cost per unit of VRE plus ‘firming’ is based on a cost of the VRE generation, the cost of the flexible energy delivery offered by the gas turbine, and an assessment of how much would be needed as a proportion of the VRE delivered.

The review offered 50 recommendations of which 49, including the idea of a generator reliability obligation, have been adopted as government policy. The key recommendation not adopted was for a certificate based Clean Energy Target with an emissions intensity multiplier to follow on from the RET post 2020.

A.2. ISF, Storage Requirements for Reliable Electricity in Australia

This recent study by ISF for the Australian Council of Learned Academies (Jay Rutovitz *et al.*, 2017) is the most current and relevant piece of work that quantifies the energy storage requirements for power system adequacy and security. Power system adequacy (synonymous with reliability) relates to the energy needed to meet customer demand while system security relates to the system's ability to withstand sudden changes or contingency events.

An hourly model of potential generation and energy demand was developed and applied to determine the current and future requirements under three scenarios (business-as-usual, meeting Australia's emissions obligations under the Paris COP 21 agreement, and meeting an ambitious renewable electricity target of 100% by 2035). Requirements were quantified in terms of power capacity (MW) and storage energy capacity (MWh).

The study found that system security gave rise to a primary requirement for power capacity while adequacy issues lead to a requirement for storage energy capacity. The model found no anticipated storage requirement for power system adequacy in 2017, with 1.3 GW of power capacity required for system security. By 2030, for a 50% renewable scenario, the modelling showed a need for 5 GWh of stored energy to maintain power system adequacy and 16.8 GW for system security. The need for storage to deliver system security was higher than the need for adequacy until very high penetrations of VRE are reached (approaching 70%).

Demand response could reduce the requirement for storage for energy adequacy by two thirds (assuming batteries and two hours of storage).

Increased interconnection was also examined as an alternative to storage for energy adequacy although the economics of the option were not analysed. Where interconnector capacity was doubled, the storage requirement was reduced by less than 1% for the middle of the road emissions reduction scenario and by 14% for the most ambitious renewable scenario.

A.3. ANU, 100% renewable electricity in Australia

This ANU study (Blakers, Lu and Stocks, 2017) analysed the cost of balancing renewable energy supply with demand (levelised cost of balancing or LCOB) for technology scenarios primarily made up of solar PV and wind generation with variability supported by pumped hydro in a 100% renewable energy scenario. It defined the component costs of balancing as PHES, capital and operating costs of transmission and spillage/losses (when storage is at capacity and there are resistance losses in high voltage systems and round trip energy losses in PHES systems). The study defined the levelised cost of generation (LCOG) as the weighted average cost of generation from generation technologies assuming no spillage. Under the study, the average LCOE is the sum of LCOG and LCOB following a determination of the level of balancing required. The LCOB is thus the cost of providing the balancing function amortised over all the sent out energy.

A.4. AECOM, Energy Storage Study

AECOM (Christiansen *et al.*, 2015) highlighted the “potential synergistic opportunity for energy storage to enable increased use of renewable energy in the Australian market”. The main findings were that energy storage is a significant enabling technology that can both smooth and shift variable renewable generation, there is higher value for storage at the end-user level than on the supply-side, and the value of storage transmission and distribution applications is highly variable, network specific and subject to regulatory barriers.

This study mainly used $/W to discuss the costs of energy storage. This metric is limited for energy storage due to the wide range of durations feasible for power output. For example, a battery can be designed for 15 minutes of storage or 8 hours of storage.

A.5. IRENA, Electricity Storage and Renewables: Costs and Markets to 2030

This IRENA study (IRENA, 2017) examined the current installed capacity of energy storage technologies and their outlook in terms of cost and application to 2030. The study examined global energy storage capacity shares by main uses and technology type. It found pumped hydro was primarily used for energy time shifting, electrochemical storage for frequency regulation, electro-mechanical storage for onsite power and thermal storage for renewable capacity firming. The study provides a useful reference for current levels of installed capacity by technology type (led by pumped hydro) and the dominant technology within a technology class (molten salt dominates thermal storage, lithium-ion dominates electrochemical, and flywheel dominates electro-mechanical).

A.6. Lazard, Levelised Cost of Storage

Lazard (Lazard, 2015, 2016) provides a like-for-like cost comparison of energy storage technologies for particular applications and against the alternative of gas fired generation. It provides a comprehensive study of major use cases for energy storage, including costs for batteries broken down into components. Lazard compares technologies with a ‘levelised cost of storage’ (LCOS). The LCOS is a levelised cost of the energy out of storage, based on an assumed cost of energy going into storage plus an assumption of the number of charge/discharge cycles in a day, along with other key performance parameters. Lazard provides the starting point for establishing a cost model for batteries and pumped hydro for the current study and data reference points for cost information.

A.7. Bloomberg New Energy Finance, Economics of End-User Energy Storage in Australia

Bloomberg (Bhavnagri, 2015) collects data on quoted costs and experience curves for battery packs and its estimates are widely referenced in the industry. Data reference points from Bloomberg are relevant to this study.

A.8. AEMC, Integration of Energy Storage Regulatory Implications

This AEMC report (AEMC, 2015) is mainly focussed on batteries, references key CSIRO reports and discusses future roll out, technology status and costs. It also contains considerable discussion of network services and how they are classified, which determines how network businesses are renumerated for providing services.

A.9. AGL, ElectraNet and Worley Parsons, Energy Storage for Commercial Renewable Integration South Australia

The report (AGL Energy; WorleyParsons Services; ElectraNet, 2015) examines the role of non-hydro energy storage within the South Australian transmission system for energy and grid stability services. The report sets out a business case including the commercial return, risks and sensitivities of a project. While capital and operating cost estimates are commercial in confidence, the report provides reference information about co-location of energy storage with a wind farm.

A.10. AEMO, 100 Per Cent Renewables Study

This AEMO study (Australian Energy Market Operator (AEMO), 2013) examines a future energy supply based entirely on renewables at 2030 and 2050 with modelling cost data inputs taken from the 2012 Australian Energy Technology Assessment (Bureau of Resources and Energy Economics, 2012). The study provides generic data inputs as points of reference with applicability limited in instances where technology is site or application specific. The study found that overall around 50% of energy would come from dispatchable sources of generation despite their higher cost per MWh as shown in Figure 36.

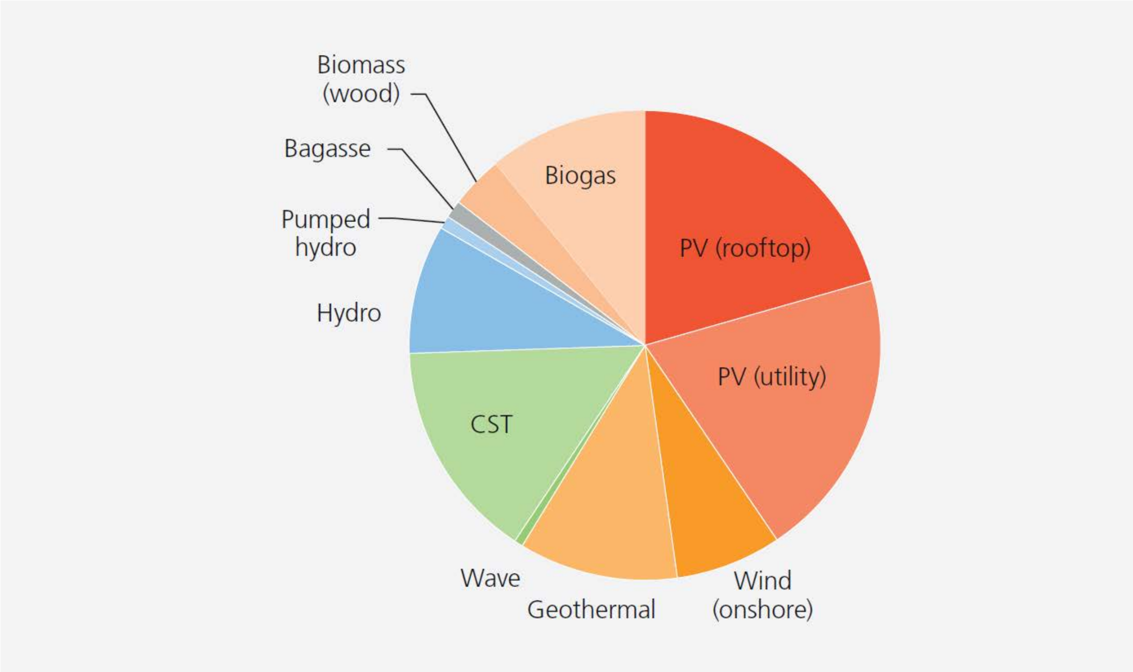


Figure 36: AEMO's scenario 1 100% renewable energy mix in 2030

A.11. Clean Energy Council, Australian Energy Storage Roadmap

This roadmap (Clean Energy Council, 2015) was a relatively early piece of work in the Australian context which provided an overview of the current status and future direction of energy storage from an industry development perspective.

APPENDIX B. TECHNOLOGY BACKGROUND

This chapter reviews the technology building blocks considered by this study and looks individually at their characteristics and status.

B.1. Variable renewable generation

B.1.1. PV

Solar PV panels contain photovoltaic cells made from silicon and other materials that convert sunlight into direct current (DC) electricity. The DC electricity flows into an inverter, a power electronic device, which converts the direct current to alternating current (AC) electricity for injection into the electricity network.

Technology status

In Australia, residential solar PV dominates the amount of total solar PV deployed to date. In recent years, there has been rapid development of solar PV plants for large-scale generation as costs have fallen to become competitive with large-scale wind plants. For large-scale solar PV plants in the NEM, single-axis tracking is now preferred. Cumulative installations in Australia over the past decade are shown in Figure 37.

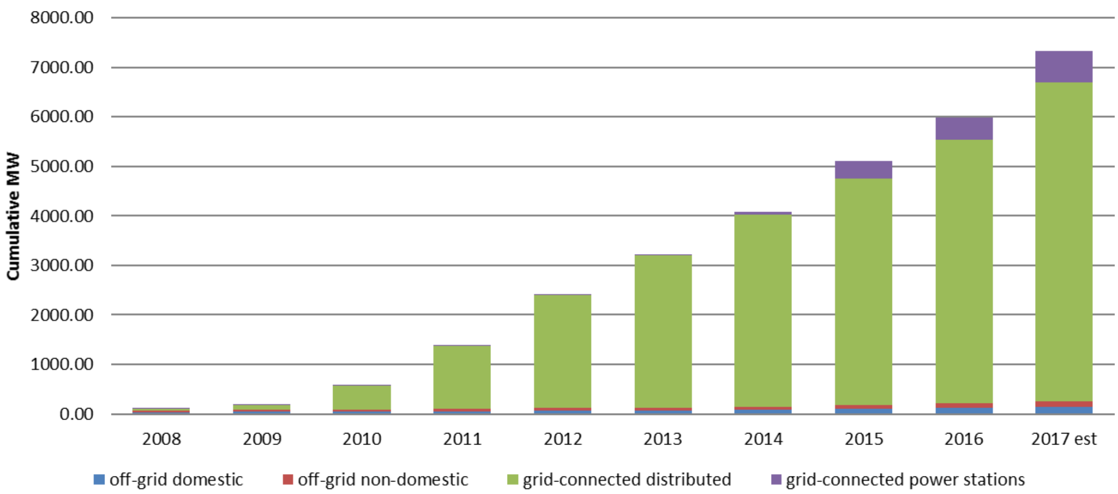


Figure 37: Cumulative Australian PV installations by category 2008-2017 (Johnston and Egan, 2016)

It is estimated that around 2.3 GW of PV farms is under construction in the NEM as shown in Table 21. It is estimated that around 1.3 GW of these projects have reached, or will have reached, financial close by end 2017.

Table 21: Large-scale solar PV projects under construction in the NEM12

Project Name	Capacity (MW)	Operational	ARENA LSS funding round
Clare Solar Farm	100	Mar-18	
Sun Metals Solar Farm	98	Mar-18	
Kennedy Energy Park solar facility	20		
Kidston Solar Project	50		Yes
Lillyvale Solar Farm	100		
Tailem Bend Solar Power Project	100		
Collinsville Solar Farm	100		Yes
Griffith Solar Farm, Parkes Solar Farm, Dubbo Solar Hub (Neoen)	100		Yes
Karadoc Sun Farm, Yatpool Sun Farm, Wemen Sun Farm (Overland Sun Farming)	320		
Ganawarra Solar Farm (Solar Choice)	60	Mar-18	
Armamara Solar Farm	132	Mid 2018	

[12] ITK estimates.

Bungala Solar Plant (Reach Solar)	220	Nov-18	
Manildra Solar Farm	42		Yes
Barcaldine Solar Farm expansion	50		
Lakeland Solar & Storage Project	10		
Oakey Solar Farm	25		Yes
Hamilton Solar Farm	58	Mar-18	
Whitsunday Solar Farm	58	Mar-18	Yes
Darling Downs Solar Farm	100	Sep-18	Yes
Ross River Solar Farm	125	Sep-18	
Emerald Solar Park	70		
Daydream Solar Farm	150		
Hamilton Solar Farm	50		
Bannerton Solar Farm	100		
Numurkah Solar Farm	38		
Hughenden Solar Farm	20		
Total	**2,275**		

Performance

Siting according to solar energy resource is more predictable than wind, which tends to be very site specific. Annual PV system output correlates well with increasing annual radiation (the solar resource), which is very good in Australia by international standards.

PV is modular and reliable with low maintenance requirements. Output can be complementary to output by wind generators (i.e. generation by solar and wind sources can occur at different times of the day).

PV output is directly proportional to the instantaneous intensity of the solar irradiance incident on the array. As irradiance varies significantly depending on cloud cover, generation from a PV array can fluctuate significantly over short periods as shown in Figure 38. As irradiance varies across the year, output also has a seasonal variation, dependent on location. This is illustrated for each state and across Australia in Figure 39, with the actual generation level dependent on MW installed, orientation and other local or system factors.

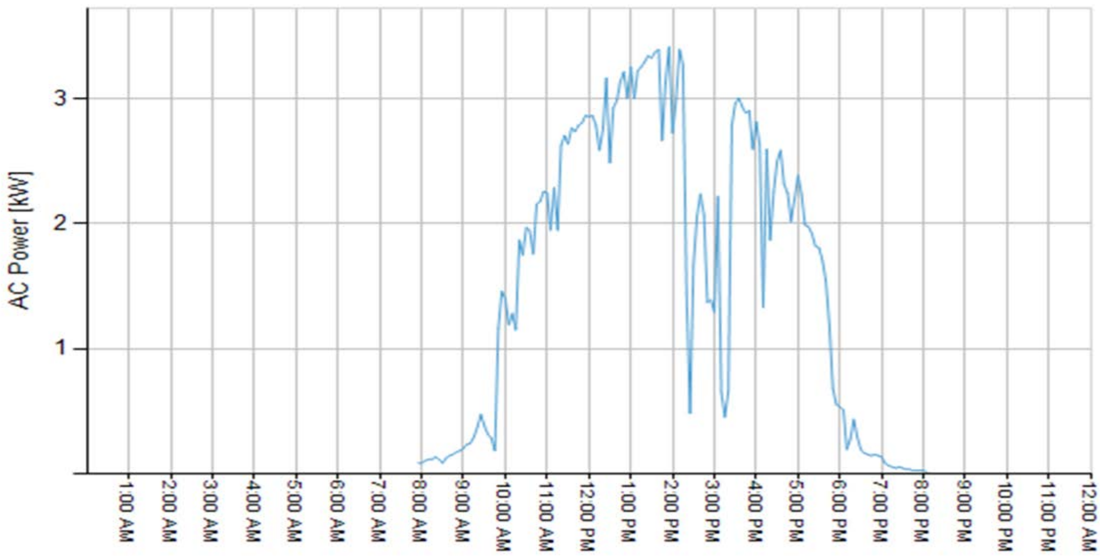


Figure 38: Variable output from a PV system caused by moving clouds

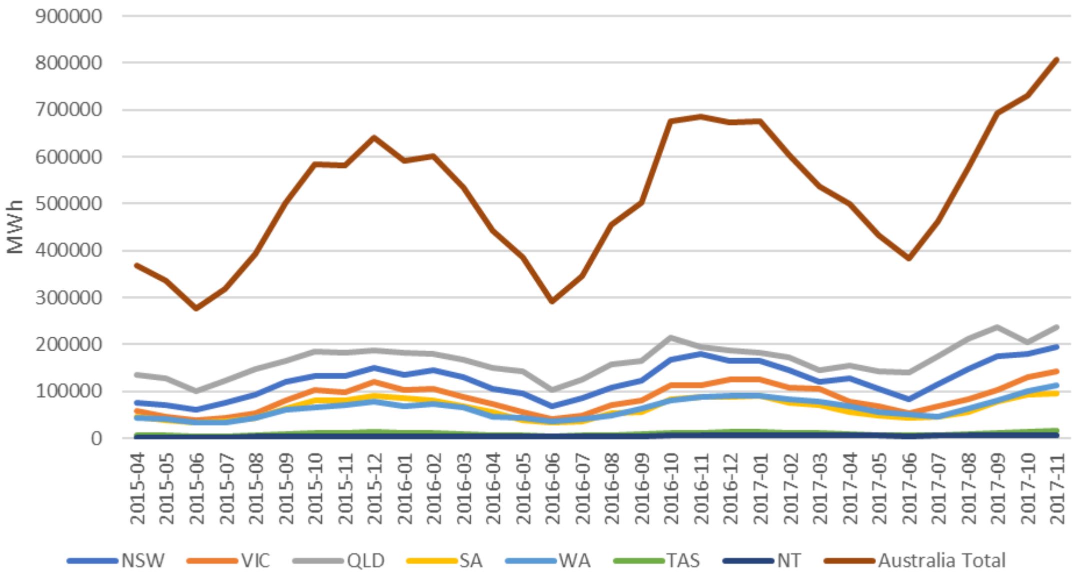


Figure 39: Output from small-scale PV systems in MWh by State 2015-2017, showing seasonal variation and increase over time (Australian PV Institute (APVI) Solar Map, funded by the Australian Renewable Energy Agency, accessed January 2018)

The capacity factor of rooftop PV systems in Australia is typically in the range of 13% to 20%. Orientation is dictated by roof orientation and slope, so may not be the ideal for maximum PV output at the location. Shading may also be an issue. Ground-mounted utility-scale systems can be optimally oriented with minimal shading, and are increasingly installed with single-axis tracking. Hence typical capacity factors in Australia are 25% to 35%.

Costs

ARENA initially approved 490 MW of capacity under its 2017 LSS round (Australian Energy Market Operator (AEMO), 2017). The capacity weighted average capex cost of the projects fell to \$2.15/W from \$2.29/W at the EOI phase of the round, which occurred six months earlier.

Our specific observations on PV system cost include the following:

- There has been a sharp fall in US\$ module prices from around US\$0.55/W in the June quarter of 2016 to around \$0.37/W in the June quarter of 2017. This was verified by JinkoSolar and Canadian Solar, the number one and number three module suppliers in Australia in the past 12 months.
- Enquiries with management involved in developing projects in Australia found that current EPC quotes on a DC basis are around A\$1.15/W to \$1.20/W. These costs exclude transformers, grid connection and financing. Adjusting for these exclusions and converting to an AC basis suggest an approximate cost for AC of \$1.70/W.
- The part owner of the Ross River PV solar farm, Palisade Investment Partners, has confirmed that a Ross River press release stating a project cost of \$225 million for its 125 MW AC project includes all costs. This equates to \$1.80/W_{AC}.

- Although undocumented, a learning curve impact is expected from the quadrupling of construction arising from the systems financed under the ARENA LSS round, notwithstanding that this is occurring in a fast-tracked or compressed time period.
- A study from the National Renewable Energy Laboratory (NREL) (Fu *et al.*, 2017) notes that single-axis tracking systems in the US have a US\$1.44/W_{DC} or US\$1.11/W_{AC} installed cost benchmark. The AC benchmark in A\$ (@ AUD1= USD 0.78) translates to A\$1.84/W_{AC}. The report notes that single-axis tracking costs in the US have declined from US\$1.54/W_{DC} in the first quarter of 2016, or a 28% drop in the past 12 months, very largely due to a reduction in module prices.
- It is difficult to forecast the near-term learning rate for PV as market dynamics are driving prices as much as underlying changes in costs due to the growth in installed capacity. Nevertheless, the NREL study provides an indication of moves in the US market over the past five years, as shown in Figure 40.

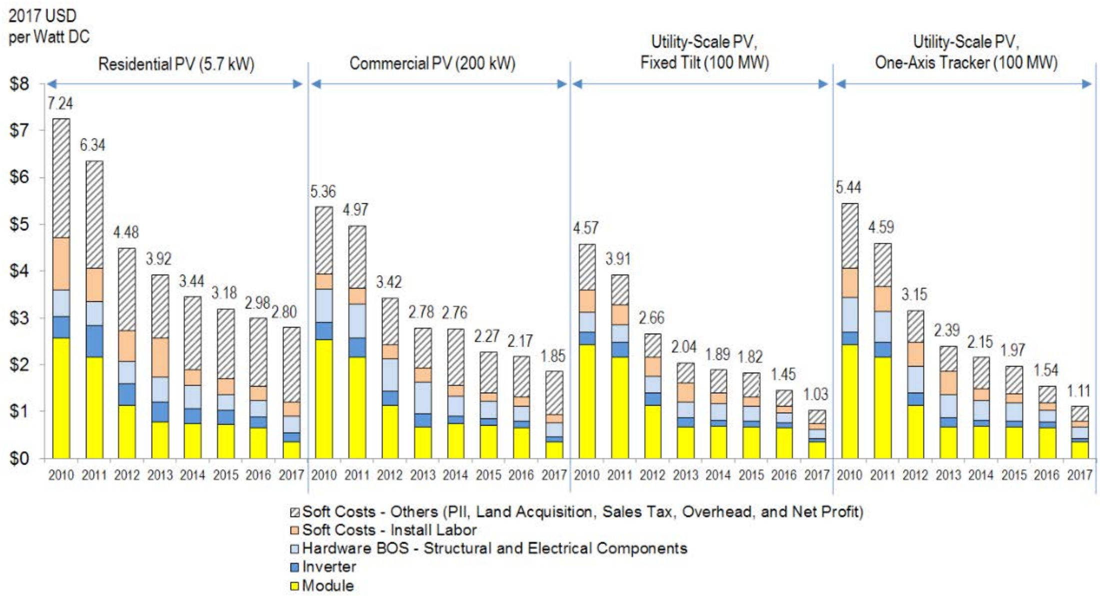


Figure 40: NREL PV system cost benchmark summary (inflation adjusted) 2010-2017

B.1.2. Wind

Wind turbines extract energy from the passing air by converting kinetic energy from rotational movement via a rotor, the force of which is then used to turn an electric generator to create electricity. Wind farms commonly aggregate the output of multiple wind turbines through a central connection point to the electricity grid.

The wind industry has standardised its systems using turbines that with a horizontal axis and three blades. Trends have been to progressively increase the size of these systems, with units now available at close to 10 MW. There has also been a trend towards using variable speed systems that rely on power electronics to transform power back to 50 Hertz AC, meaning the turbines are not synchronous generators.

There is also a trend towards designs optimised for lower wind speeds, by increasing the rotor diameter for a given generator capacity.

Technology status

Wind is a mature technology. It historically has been the lowest cost form of non-hydro renewable electricity generation at large scale, and has fulfilled most of the capacity additions under the national RET to date.

A list of new wind projects that have recently been or are in the process of being constructed is shown in in Table 3. This list of projects amounts to about 2.9 GW in total.

Table 22 – Wind farms recently commissioned or currently under construction[13]

Wind farm Name	Capacity (MW)	Operational
Hornsdale 1, SA	102	Jan-17
Hornsdale 2, SA	100	Jun-17
Hornsdale 3, SA	109	Jun-18
Ararat, VIC	240	May-17
White Rock, NSW	175	Oct-17
Mt Emerald, QLD	180	Jun-18
Sapphire, NSW	270	Jul-18
Mt Gellibrand, VIC	132	Jun-18
Kiata, VIC	30	Mar-18
Crookwell 2, NSW	91	Mar-18
Kennedy, QLD	20	
Silverton, NSW	200	Sep-18
Bodangora, NSW	113	
Stockyard Hill, VIC	530	
Cattle Hill, TAS	144	Jun-20
Coopers Gap, QLD	453	
TOTAL	2889	

[13] ITK estimates.

A feature of the most recent projects is an increase in size. For instance, Stockyard Hill is 530 MW and Coopers Gap 453 MW. This has been facilitated in part by an increase in turbine size with 3.0 MW to 3.5 MW turbines now readily available from GE, Vestas and Goldwind.

Performance

Wind resources are highly site specific, meaning a thorough assessment is required to ensure turbine performance and lifetime will be sufficient to warrant the investment. In general terms, the southern edges of the Australian continent have the highest level of wind resource although there are wind resources in all states that would be considered excellent in other parts of the world. The average capacity factor of wind farms around the globe was 23% between 2007 and 2016, while Australia had an average capacity factor for its wind farms of 33% (J. Rutovitz *et al.*, 2017).

The high-energy wind resources are associated with the various weather systems as they pass over the continent. As the levels of renewable penetration have grown, there is increasing interest in sites characterised by wind driven by the daily cycle of temperature on the land mass. These offer the potential of generation that is extremely predictable, and can anti correlate with the output of PV. The wind farm being developed as part of the Kennedy Energy Park in North Queensland is an example of this.

Wind projects experience strong economies of scale, so cost effectiveness increases rapidly with increasing project scale.

Costs

Based on the recent wind power projects that have disclosed cost and capacity data, the median capital cost is estimated to be around $2.1 million/MW and the median capacity factor around 38% after including grid connection and other non-EPC costs (see Table 23).

Table 23: Median capital cost estimates and capacity factor, recent wind farms

	MW	Project cost A$m	$m/MW	Output TWh	Capacity factor
Mt Emerald	180	380	2.11	0.55	35%
Mt Gellibrand	132	258	1.95	0.43	37%
Kiata	30	75	2.50	0.13	49%
Crookwell 2	91	200	2.20	0.32	40%
Silverton	200	450	2.25	0.78	45%
Bodangora	113	236	2.09	0.36	36%
Coopers Gap	453	850	1.88	1.50	38%
Median			2.11		38%

Capital costs have fallen from about $2.3 million/MW over the past five years, and capacity factors appear to have increased. In addition, PPA prices have fallen significantly. The Silverton wind farm is at $60/MWh real, Coopers Gap at less than $60/MWh real, and Stockyard Hill at less than $55/MWh real. These compare with PPA prices in the range of $80/MWh five years ago and over $100/MWh for similar projects developed prior to 2012. PPA prices have fallen faster than underlying capital costs and this is likely due to a fall in the required cost of capital.

The other development in the industry, which is well documented (Hernández, Telsnig and Anahí Villalba Pradas, 2017), is that turbines are being adapted for low wind speed. Wiser and Bolinger (Wiser and Bolinger, 2016) discuss the drivers of US wind PPAs which, with the assistance of the production tax credit, have fallen to US$20/MWh in the USA:

> *"Focusing only on performance in 2015 (to partially control for time-varying influences) and parsing capacity factors by project vintage tells a more interesting story, wherein rotor scaling over the past few years has clearly begun to drive capacity factors higher. The average 2015 capacity factor among projects built in 2014 reached 41.2%, compared to an average of 31.2% among projects built from 2004–2011 and just 25.8% among projects built from 1998–2003. The ongoing decline in specific power has been offset to some degree by a trend – especially from 2009 to 2012 – towards building projects at lower-quality wind sites. Controlling for these two competing influences confirms this offsetting effect and shows that turbine design changes are driving capacity factors significantly higher over time among projects located within given wind resource regimes."*

The same source notes that capital costs in the USA in 2015 were at US$1.69 million/MW, down US$0.64 million/MW from 2009, which is 27.5% or a compound rate of 5%. NREL forecasts ongoing capital cost reduction in US wind farms at a rate of about 3% per year.

B.2. Electricity storage

B.2.1. Batteries

Batteries, or more precisely electrochemical energy storage, use a reversible chemical reaction to convert electricity into stored chemical energy. Movement of electrons or ions within a battery cell allows electrons to be released at a negative electrode to flow as an electrical current in an external circuit, and accepted at a positive electrode. The electrolyte between the electrodes is a liquid, solid or gel material according to the type of battery. There is a large range of battery chemistries commercially available and under development (Cavanagh *et al.*, 2015).

For this study, a battery storage system comprises the basic electrochemical cells that store energy together with the power conditioning and inverter systems that manage the charging process and convert the output energy to AC at the correct frequency.

The lead-acid battery has a long history in uninterruptable power supplies and standalone power systems, and through these applications represents the majority of installed battery capacity worldwide. The li-ion battery was originally developed for portable devices, and has now been scaled up for use in electric vehicles and the power sector. Other chemistries in use and under development include zinc-bromine, vanadium redox, sodium sulphur, or nickel metal hydride. Batteries types can be categorised as:

- Conventional: Electrochemical cells with a stationary electrolyte.
- Redox flow: Battery technology where the energy is stored directly in liquid electrolyte solutions that may be pumped into external tanks. An advantage of this technology is that the storage capacity can be increased through larger electrolyte tanks. It is also expected that flow batteries can provide lower cost storage at large scale. The most developed example is the vanadium redox flow battery.
- Hybrid redox flow: Uses a combination of liquid and stationary charge storage mechanisms. The zinc-bromine battery is the most commercially developed example.
- High temperature: Uses molten metals and molten salts as an electrolyte to achieve high energy and power densities.
- Hybrid: Combines conventional and advanced technologies, for example batteries with supercapacitors, through innovations with electrode, electrolyte, and separating membrane technologies.

There is a general view that the li-ion battery is currently the most cost-effective and industry best practice solution, although other promising approaches may reach commercial maturity over time. For this study we adopt the cost and performance characteristics of li-Ion as representing batteries as a general class. When learning curve approaches are used to postulate future cost reductions they cover the possibility that favoured chemistries and configurations may evolve over time.

Batteries can both smooth and shift VRE generation. They can also deliver multiple support services to electricity networks including peak demand mitigation, voltage regulation, and contingency services.

The value of battery storage for transmission and distribution applications is highly variable, network specific and subject to regulatory barriers. Most transmission and distribution operators have trialled batteries on their networks to understand their potential role, and some operators now use batteries regularly on lengthy rural networks where high value can be obtained. Following the South Australian system black in September 2016, which was characterised by an unprecedented rate of change of frequency that could not be contained by existing contingency measures, large batteries for fast frequency response (or inertial) services have been widely discussed and now exist. The Tesla 'big battery' commissioned in November 2017 has 70% of its 100 MW power capacity reserved for contingency services through the arrangement made with the state government.

Batteries are highly scalable and, given a suitable control and communications system, most of these requirements can be served equally well by utility-scale batteries (typically MW scale) or a large number of customer batteries (kW scale). Batteries can be designed for a range of applications with different electrical energy storage levels and power outputs. They remain expensive in terms of energy storage capacity compared to pumped hydro. However, batteries are economical as fast-responding power with modest storage capacity, enough for say 30 minutes to 120 minutes of discharge at full power, which is the niche where many existing commercial applications can be seen. Residential energy storage fulfils multiple ambitions, not all of which are economic, and as such is becoming a common addition to rooftop solar systems with a strong competitive environment bringing system costs down rapidly.

It is an open question whether residential and commercial customer batteries, or utility-scale batteries connected at strategic network locations or generators, will ultimately present the greatest total energy storage capacity to the Australian grid.

Battery round-trip efficiency is typically around 88% to 93% for li-ion batteries including power conversion from AC to DC when charging and back again on discharge. Li-ion battery degradation is around 1% to 5% of available energy capacity per year and depends on the manner of use of the battery. The end of life for a battery is commonly considered to be when its useable capacity has declined to 80% of its original value: 1.5% degradation per year means the battery lasts 15 years by this measure and 2.2% means 10 years. A degradation rate of 5% means just over 4 years, which would be an excessively demanding application and potentially un-investable.

Costs

A cost model for battery energy storage presents particular challenges. As the supply chain matures and scales up, costs are decreasing very rapidly and demand is correspondingly surging for what many regard as a transformative technology for power systems. Secondly, following the trend of solar PV generation, batteries are highly scalable and residential systems may in aggregation make a significant a contribution to the power system as utility-scale batteries, so a cost model should be valid over many orders of magnitude.

However for both residential and utility battery systems, it is a significant challenge to scale the battery, power conversion, and remaining costs with power and energy capacity because the system configurations vary according to application, and the balance-of-system and the ‘soft’ costs are not clearly linked to power or energy. Ardani et al. advise that:

> *“some studies report storage costs in both $/kW and $/kWh by assigning the power components of the system (e.g., inverter, balance of system) to the power metric of $/kW and the energy components of the system (e.g., battery) to the energy metric of $/kWh. The challenge with this approach is consistently defining the power and energy components of storage systems to avoid variability in cost reporting across different studies. The usefulness of storage cost metrics for comparison purposes is limited by the sensitivity of the metrics to the storage application and the definition of power versus energy components; therefore, we report total installed system price as our primary metric.”*

Similarly, this study's approach is to use the total installed system price as primary data, and develop a dual-power-law model to express the kW and kWh dependency of this price without explicitly assigning components as related to power or energy. The model is:

$$\mathrm{Cost}(P, E) = \left(AP \left[\frac{P}{P_{\mathrm{ref}}} \right]^{a-1} + BE \left[\frac{E}{E_{\mathrm{ref}}} \right]^{b-1} \right)$$

Where:

P	Power capacity of a battery system
P_{ref}	Reference power capacity for scaling
A	Coefficient of cost that scales with power
α	An exponent not more than 1
E	Energy capacity of a battery system
E_{ref}	Reference energy capacity for scaling
B	Coefficient of cost that scales with energy
b	An exponent not more than 1

This model has been fitted to the cost data obtained by minimising the weighted least-squares relative error between the cost data and the modelled costs. The four parameters (A, a, B, b) were obtained by fitting.

Table 24 summarises the cost data and the model fit obtained. As a starting point, each source is given an equal weight of 20 and those sources with multiple line items, like Lazard (Lazard, 2016), receive a smaller weight per item. Based on an assessment of the reliability of each data source, some of the weights have been modified. It is therefore worth discussing each of the sources.

The published sources are well documented and cover a wide range of scales, that is 4-5 orders of magnitude, and cost ranges are provided by Lazard and Adani et al. (Ardani *et al.*, 2017), which are included in the model fit by using the two extreme values with equal weight. The wide range of costs for the frequency regulation use case in Damato et al. (Damato *et al.*, 2016) created a distortion in the model fitting and was omitted because it did not usefully contribute to the information available from other sources. Both the residential systems in Ardani et al. were more expensive than the model fit, perhaps reflecting a more active and competitive market in Australia.

The remaining cost data are from interviewed industry sources and derived, for the most part, from actual quoted or installed battery systems. Source #1 provided two examples of distribution substation batteries that are counterintuitive, with a much greater energy capacity costing less, probably reflecting different inclusions in the two quotations that were not fully described. The weight used for model fitting is therefore less than would be the case for this otherwise trustworthy source.

Table 24: Battery storage costing model: inputs and fit (in AUD)

Source	Use case	MW	MWh	Reported	Weight	Modelled
Lazard	Transmission	100	800	469-1115m	2	575m
Lazard	Peaker replacement	100	400	253-577m	2	291m
Lazard	Frequency regulation	10	5	6.8-11.4m	2	5.7m
Lazard	Distribution substation	4	16	10.7-22.3m	2	11.9m
Lazard	Distribution feeder	0.5	1.5	1.1-2.2m	2	1.2m
Lazard	Microgrid	2	2	2.4-3.1m	2	2.0m
Lazard	Islanded grid	1	8	5.3-12.1m	2	5.7m
Lazard	Commercial/Industrial	0.5	2	1.4-3.3m	2	1.6m
Lazard	Commercial appliance	0.1	0.2	157-349k	2	205k
Lazard	Residential	0.005	0.01	13-24k	2	15k
EPRI	Utility	20	80	55.6m	2	59m
EPRI	Bulk storage #1	40	240	133-208m	2	173m
EPRI	Bulk storage #2	75	300	160-270m	2	219m
EPRI	T&D Grid support #1	15	60	36-56m	2	44m
EPRI	T&D Grid support #2	3	6	4.8-8.0m	2	4.9m
NREL	Residential #1	0.003	0.006	14k	5	9.5k
NREL	Residential #2	0.005	0.02	29k	5	21k
Source #1	Distribution substation #1	30	30	37m	5	26m
Source #1	Distribution substation #2	28	54	33m	5	42m
Source #2	Commercial	3	2.9	2.77m	20	2.9m
Source #3	Commercial #1	10	20	12-16k	2	16k
Source #3	Commercial #2	10	40	20-26k	2	29k
Source #4	Residential #1	0.0048	0.0098	12.0k	10	14k
Source #4	Residential #2	0.005	0.0128	16.8k	10	16k
Source #5	Utility	100	400	378m	10	291m

Source #2 is a company specialising in solar/storage installations for commercial customers, which is a market segment where rapid growth is anticipated following the lead of the residential market. The cost provided is for a recently quoted system. Source #3 is a major battery manufacturer that provided indicative fully installed costs for two utility-scale batteries, 2-hour and 4-hour systems respectively, and a residential cost estimate on their website. The latter is unrealistically lower than the other estimates of fully installed costs, including one with batteries from the same manufacturer, suggesting that the estimate lacks many inclusions. Therefore, it is omitted from model fitting. Source #4 specialises in technology-agnostic battery controls and provided quotations for recently installed residential systems. Source #5 is a European battery energy storage integrator with deep experience of utility-scale systems.

B.2.2. Pumped hydro

PHES is the most common form of electricity storage in the world today. This can be through existing hydroelectric facilities (on-river) or off-river closed loop systems using dams or reservoirs, for example. PHES advantages include a long life with no capacity fade and the ability to store energy for long durations. Turbines can be variable or fixed speed and these have different performance parameters.

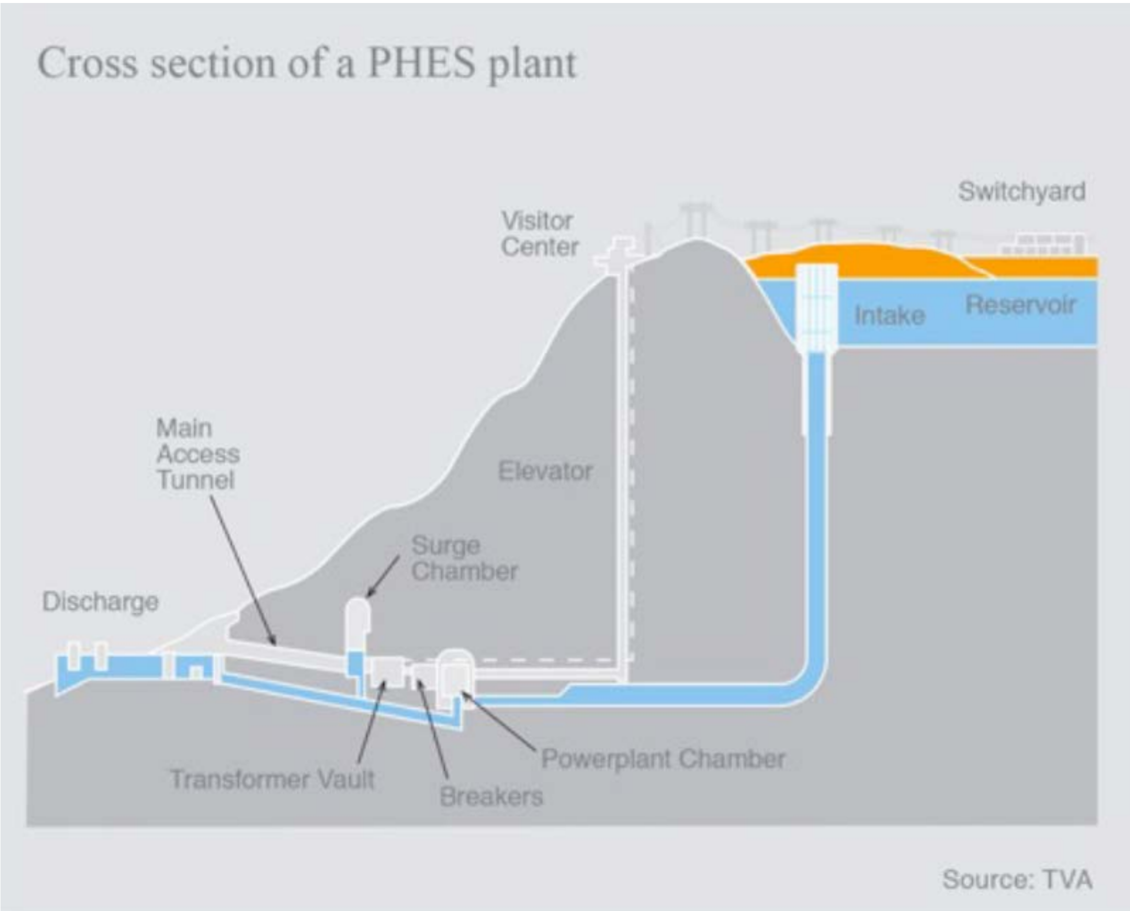


Figure 41: PHES system schematic

Technology description and value provided

As illustrated in Figure 41, PHES consists of two water reservoirs, one higher than the other. The reservoirs can be completely manmade or existing natural reservoirs can be utilised. At times of low electricity demand, water is pumped from the lower reservoir to the higher one using external power. When demand for electricity is high, the accumulated water in the upper reservoir is released, passing through a generating turbine to generate electricity.

PHES does not necessarily require a continuous supply of water as generally no water is lost in the process of storing and generating energy (other than evaporation or leakage). In addition to off-river closed loop systems, PHES is often integrated with existing hydroelectric facilities that have seasonal water supplies.

PHES design is very site specific. A major site specific aspect is the height difference (head) between upper and lower storages. This head determines the pressure at turbine inlet and also the amount of energy stored per volume of water. Turbines are configured to match the pressure characteristics encountered.

At least three styles of pumped hydro can be identified:

- Conventional turkey's nest: This requires a separate upper (turkey's nest) and lower reservoir and is generally environmentally demanding. Lack of access to a transmission network can be an impediment. The proposed Kidston PHES plant in north west Queensland is an example although it also has elements of underground pumped hydro.
- Seawater: The lower reservoir is the ocean with the upper reservoir on a seaside elevation. The EnergyAustralia proposed site at Cultana, South Australia, is an example. Many potential coastal sites close to load will typically see environmental or amenity objections.
- Underground: This style takes advantage of an existing but worked out underground mine. An underground cavern is built at the base of the mine shaft and a reservoir at the top. A serious, but not yet well publicly documented proposal for such a site has been put forward by the Gupta Group as part of the Whyalla Steel repowering proposal. AGL have also tentatively proposed such a plant in the Liddell area in NSW.

Technology status

PHES represents 97% of global total installed capacity of electricity storage systems (IRENA, 2017). It is a mature technology with operating experience dating from the 1940s and earlier. Total installed capacity (in terms of power) is in excess of 130 GW. Sabihuddin, Kiprakis and Mueller (2015) state that there are 21.8 GW of PHES in the USA, 24.6 GW in Japan, and smaller amounts in other countries. In Australia, the largest PHES facilities were built in the 1970s and there is renewed interest in the technology with feasibility assessments underway for the expansion of existing facilities in NSW and Tasmania. Lead time for construction is relatively long and it is not as modular as some of the new and emerging electricity storage technologies.

The significant existing PHES systems in Australia include:

- Tumut 3 NSW: offers power capacity of 600 MW in conjunction with the conventional 1500 MW hydroelectric facility, completed in 1973
- Shoalhaven NSW: 240 MW, completed in 1977
- Wivenhow Qld: 500 MW, completed in 1984.

New initiatives in PHES systems in Australia are receiving considerable interest at present including:

- the proposal to add to the Snowy Mountains hydroelectric scheme with additional tunnels and pumping/generating units, dubbed Snowy 2.0
- a major development of integrated PV and PHES by Genex in Kidston, north west Queensland
- a study by EnergyAustralia for a seawater PHES system at Cultana in SA
- investigations by Hydro Tasmania into the potential addition of PHES systems to their existing hydroelectric dams.

ROAM Consulting used topological analysis coupled with land-use assessments to evaluate the PHES capacity that could be developed in Australia (Winch *et al.*, 2012). The Melbourne Energy Institute prepared a thorough overview of the technology and its potential in Australia, which is also a very good reference source (Hearps *et al.*, 2014). Most recently, comprehensive GIS mapping by the ANU team (Blakers *et al.*, 2017) identified 22,000 potential PHES sites across Australia. None of these assessments included the additional potential of underground pumped hydro in disused mine sites, exemplified by the Genex project.

Performance

PHES advantages include a long life with no capacity reduction, low losses of stored energy (i.e. self-discharge rates) and an ability to store a large volume of energy for long durations (i.e. days, weeks or months). The main disadvantages are the variability of the water resource with rainfall patterns, and the large environmental footprint of building dams.

Historically, the main use for PHES has been electric energy time-shifting from low demand to high demand periods. PHES can be also used to assist with frequency regulation and voltage support.

Round-trip efficiencies can vary between 70% and 80% depending on characteristics. The length of the penstock relative to head is one significant determinant.

PHES turbines can start within a few minutes. There is also the potential to operate them in synchronous condenser mode. This involves drawing power into the generator to spin the turbine at full speed in the absence of water flow. This consumes power continuously at approximately 1% of the generating capacity. It provides the electrical system with additional inertia. It also facilitates a ramp to full power within 20 seconds.

Turbines can be variable or fixed speed and these have different performance parameters. Variable speed systems allow PHES to offer power regulation during both pumping and generation. A system configured to enable simultaneous pumping and generation can provide finer frequency control.

Costs

Melbourne Energy Institute (MEI) has reviewed the literature on the costs of PHES systems and, where possible, expressed capital costs on a per unit of power electricity generation capacity (A$/MW) and a per unit of energy stored (A$/MWh) basis (Hearps *et al.*, 2014). Excluding high estimates, MEI's review suggests a range in capital cost per unit of electricity generation capacity of A$0.6m/MW to A$4.3m/MW and capital cost per unit of energy stored at $A100,000/MWh to $A500,000/MWh.

From its analysis of 80 recent hydroelectricity projects with head heights of less than 100 metres to 800 metres, MEI found a strong relationship between cost and turbine power capacity, and a weaker relationship between cost and net head.

MEI developed a model to identify costs for example PHES sites. This includes reservoir, tunneling, electrical and mechanical costs including pumps and turbines as system components of PHES, and cost factors such as horizontal and vertical distances between reservoirs, size of water storage volume, dam construction type, dam geometry and turbine/pump capacity and configuration.

The MEI study also refers to analysis for NREL (2012) showing the bottom-up capital costs for an indicative 500 MW PHES with 10 hours of storage +/- 50% using an existing lake or river as the lower reservoir was US$2230/kW and US$223,000/MWh (both in 2012 dollars) with a capital cost breakdown as follows: powerhouse (37%), upper reservoir (19%), EPC (17%), owner costs (17%), tunnels (6%) and powerhouse excavation (4%).

Blakers et al. (Blakers, Lu and Stocks, 2017) have studied scenarios for 100% renewable energy in Australia, where generation is exclusively provided by PV and wind with the essential dispatchable requirement provided by off-river PHES systems. They have carried out geographic information system (GIS) mapping to identify a very large number of geographically suitable sites with sufficient height differential (Blakers *et al.*, 2017). This suitability is further supported by major transmission upgrades. The ANU study assumes an 80% round-trip efficiency and a 2016 construction cost of:

- $800/kW for penstocks, machinery and power conversion
- $70/kWh for pond excavation and construction.

The Blakers et al. study is based on a 200 MW plant with 600 metre head, twin 20-metre deep five hectare turkey nest ponds with earth walls built on flat land, and penstock slope of 13 degrees. These costs are scaled for different head and pond sizes, while the additional cost of transmission to a high voltage node is estimated separately.

Dubai Electricity & Water Authority (DEWA) announced in June 2017 (Poindexter, 2017) that it has awarded a US$15.8 million consultancy to France's EDF for a US$523 million 250 MW pumped storage project at Hatta Dam located in Dubai, United Arab Emirates.

The PHES facility will be located in the Hajar Mountains and generate electricity using water from the Hatta Dam, which can store up to 1716 million gallons, and an upper reservoir that will be built to store up to 880 million gallons. According to DEWA, the upper reservoir will be 300 meters above the dam level. During off-peak hours, turbines will use solar energy to pump water from the lower dam to the upper reservoir. The facility plans to have a 90-second response time to generate energy for

DEWA's grid. Analysing the water figures, the plant will have a store of 2722 MWh, which at 80% efficiency will generate 2178 MWh_e.

EnergyAustralia has been carrying out a detailed feasibility study for a seawater PHES system at Cultana in South Australia (EnergyAustralia, ARUP and Melbourne Energy Institute, 2017). The Cultana site costings are based on a 225 MW seawater plant with six hours of storage at an estimated capital cost at just over $2.1 million per MW of capacity or $270 per kWh of storage. Operating costs have been estimated at about $11 million to $12 million per annum.

Recently Snowy Hydro has completed a feasibility study (Snowy Hydro, 2018) for the Snowy 2.0 project using two existing reservoirs at its iconic national park site. The proposed project would have 2000 MW power capacity and 350,000 MWh of storage, which is very much larger than any other PHES project encountered during this study. The cost is anticipated to be between $3.8 billion and $4.5 billion, which is broadly compatible with the per MW costs seen for international projects but much cheaper on a per-MWh basis, as would be expected given the reservoir capacity is very large and already exists. Transmission costs would be additional, including a 2000 MW line to the NSW grid and a 1300 MW upgrade to the NSW-Victoria interconnector. Because of the broad impact this project would have on the NEM, Snowy Hydro has argued that it is not reasonable to assign all these transmission costs to the PHES project, and a regulated cost sharing determination should be made. According to these costings, Snowy 2.0 would be a highly competitive energy storage for medium-to-long durations.

Internationally, a series of pumped hydro projects was identified for this study using Canaccord Genuity broker research (Canaccord Genuity, 2017). The broker research identified six operating projects that have started since 2003 and two projects under construction. The Canaccord data was verified to the best extent possible, using publicly available information but without directly contacting the management of the various operations. The project information is shown in Table 6. A unit capital cost was calculated based on 70% capacity utilisation, on a one cycle per day approach. However, the numbers are rough estimates at best given it was beyond the scope of this study to undertake a more detailed examination of international projects, and the intent was only to provide context for the Australian proposals.

Table 6 shows that in terms of unit cost, several of the international PHES projects fall within a range, while in other cases the numbers are 'outliers'. This study's research of international projects illustrates that new projects can take many years to permit and build. For instance, Dominion Energy owns the largest operating pumped hydro site in the world and is looking at constructing an 850 MW new build station worth US$2 billion in Virginia. Management stated that construction of that site would take five to seven years with the approval process adding a further three years (Booth, 2017).

Other commercial-in-confidence data have been used in the analysis.

Table 25: Selected international pumped hydro projects

Country	Germany	China	Italy	USA	Spain	Austria	South Africa	Wales
Year	2003	2004	2005	2012	2013	2015	2017	2021
Project	Goldisthal	Tianhuangping Zheijian	Pont Ventoux-Susa	Olivenhain	La Muela	Reisseck II	Ingula	Glyn Rhonwy
Power capacity (MW)	1060	1836	150	40	1700	430	1332	100
Hours storage	7.0	4.5	6.7	5.0	8.1	6.3	16.0	16.0
Reported total cost (A$m)	1038	1662	133	187	2462	615	4375	261

B.2.3. Hydrogen

Chemical processing (dominated by ammonia and methanol production) and oil refineries are the largest consumers of hydrogen in the world today. There are well established companies producing, storing and transporting hydrogen for these industries.

The current main method of producing hydrogen is steam reforming of natural gas.

Utilising VRE sources to power electrolysis units to produce hydrogen and then using the hydrogen when required to generate electricity has been demonstrated in numerous locations around the world. However, due to the high costs, the demonstrations have been at a small-scale. For example, the Australian Antarctic Division undertook a wind-hydrogen trial to power one of its remote research facilities between 2005 and 2007.

The main value of hydrogen storage is the ability to store large quantities of energy for long periods with minimal losses. Hydrogen is also versatile as a feedstock, with values for use in transport, chemical processing, fertiliser production (via ammonia) and the potential to enable the export of renewable electricity in liquid form.

Technology status

While electrolysis technology is mature, research is ongoing into improving its efficiency, reducing costs and improving how electrolysis units perform when part loaded from VRE sources.

Hydrogen has a very high energy content by weight (lower heating value 119.96 MJ/kg). However, it has a very low density at atmospheric pressure (~11m^3/kg) and must be compressed for storage, which involves energy and financial costs. High-pressure tanks (35 Mpa and 70 Mpa) are available but costs are relatively high. At 70 Mpa (700 times atmospheric pressure) about 5 kg of hydrogen can be stored in a 125-litre tank, which is suitable for a vehicle. For bulk hydrogen storage, underground caverns are orders of magnitudes less expensive than tanks and, typically, involve less compression (8 to 10 Mpa). An alternative to compression is conversion to ammonia, which has a higher energy density by volume of 6.8 MJ/litre than that of liquid hydrogen (4.8 MJ/litre), and is under physical conditions that are much easier to achieve and maintain (Lan and Tao, 2014; Institute for Sustainable Process Technology, 2017). This is an important consideration for transport.

Fuel cells are one of the key enabling technologies for increased hydrogen usage, particularly in the transport sector. However, due to their costs and durability issues, this study has modelled a combined cycle gas turbine system adapted to hydrogen combustion to generate electricity from the stored hydrogen.

The components of a hydrogen storage system are discussed in more detail in the following sections.

Electrolysis

The production of hydrogen through electrolysis involves separating water into hydrogen and oxygen using electricity. This approach has potential environmental benefits for the electricity, transport, fertiliser and export fuels sectors. However, electrolysis systems face economic competitiveness challenges due to their high capex and the cost of electricity.

The option of using electrolysis to store VRE as hydrogen and then use this hydrogen in a dispatchable generator has been demonstrated at several locations around the world.

The uptake of hydrogen production via electrolysis is largely driven by high-value markets such as transport where it competes with >$20/GJ diesel. Production of ammonia (NH_3) is another potential high value use for hydrogen from electrolysis.

The hydrogen references examined for this study reported a range of electrolysis efficiencies of between 61% and 75%. Care needs to be taken when interpreting electrolysis efficiency figures as some methodologies use hydrogen's higher heating value (HHV,141.80 MJ/kg), while others use lower heating value (LHV, 119.96 MJ/kg) and many reports do not document which heating value they have used in their efficiency calculation.

The following figure illustrates the dependency of hydrogen produced from electrolysis on the electricity cost.

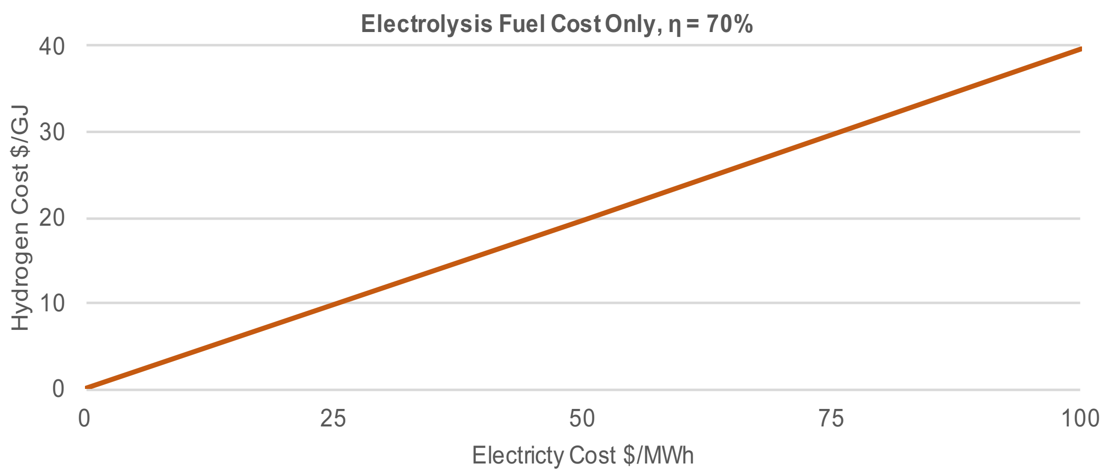


Figure 42: Marginal cost of hydrogen ($/GJ HHV) from electrolysis, before capex of plant and compression plus storage are included

For comparison, typical steam methane reforming costs have been estimated to be in the range of $1.50/kg to $2.50/kg. This is $12.50/GJ to $20.84/GJ (LHV) (Hinkley *et al.*, 2016).

In addition, electrolysis produces oxygen. This can also be sold, which effectively reduces the cost of the hydrogen. The 2003 National Hydrogen Study reported $22/GJ for hydrogen production from electrolysis (not including compression and delivery costs) based on an electricity cost of $60/MWh. The report noted that this hydrogen cost can be reduced by $3/GJ to $5/GJ, if the oxygen produced is also sold.

While alkaline water electrolysis is widely used by the chemical industry, it has relatively slow ramp rates. It is the more expensive polymer electrolyte membrane electrolysis that is favoured for VRE storage due to its ability to move from part-load to overload in a rapid manner. Solid oxide electrolysers operate at temperatures above 500ºC but are also attracting interest for storing VRE due to their ability to also operate as a fuel cell and generate electricity.

Storage

Hydrogen storage is often visualised as in a tank, similar to compressed natural gas. This can be practical when considering transport applications. However, for large quantities of hydrogen, underground storage is estimated to be orders of magnitude cheaper than tank storage.

For the purposes of this study, we have only examined underground storage options. Capital costs vary depending on whether there is a suitable natural rock cavern or rock formation. Using abandoned natural gas wells is the cheapest option, followed by solution salt mining (Ferrari, Mancuso and Cotone, 2012). Storing hydrogen in underground caverns has been estimated to cost as little as US $0.3/kWh (Schoenung, 2011). Boring or mining underground caverns is also a viable option that has the greatest site flexibility.

Pipelines can also be used to move and store hydrogen. However, a hydrogen pipeline costs more than a natural gas pipeline due to the need for very effective seals plus greater requirements for embrittlement and corrosion protection.

Compressors are an additional cost for hydrogen storage systems. The choice of storage pressure depends on several factors but for storage of bulk quantities of hydrogen underground, pressures of 8 Mpa to 10 Mpa are typical. In principle, the energy input for compression can be recovered on expansion, or if the pressure is in line with the need for use in the combustion stage of a turbine, the pressure is required in any case.

Power from hydrogen

Fuel cells convert hydrogen and oxygen to electrical energy. An electrolyser with hydrogen storage within a fuel cell forms an electrochemical storage system that is conceptually similar to a battery. Fuel cells are classified by the type of electrolyte they use and by the difference in startup time, ranging from one second for proton exchange membrane fuel cells to 10 minutes for high temperature solid oxide fuel cells.

Hydrogen can also be used as the fuel for conventional combustion gas turbines. In combined cycle configurations, conversion efficiencies can be close to 60%. The first large-scale (16 MW) combined cycle hydrogen turbine was commissioned in 2010. It was built with an investment of 50 million Euros (Power Engineering, 2018). These systems can achieve efficiencies above 65% (LHV) (Griffith, 2016).

Costs

Developing whole-of-system cost models for utility-scale hydrogen storage systems is a significant challenge. Most references do not explicitly break down the costs for each hydrogen storage system component (electrolysis, compression, storage and generation) in a consistent or transparent manner. For example, the South Australian Green Hydrogen Study (Advisian, Siemens and ACIL Allen, 2017) contains no breakdowns of hydrogen storage system component costs beyond an assumed electrolysis capex of $3.7 million per tonnes of hydrogen per day.

The references analysed for this study report hydrogen production in a wide range of units but do not document whether the efficiencies were higher heating value (HHV) or lower heating value (LHV). There also can be boundary issues between the hydrogen storage system components, e.g. compression costs are often not documented separately.

Most references also report wide ranges of costs for the hydrogen storage system components. These ranges are likely due to the scale of the units, purchased versus installed costs, and potential boundary issues between component costs from different sources.

Comparing underground storage costs is particularly challenging due to the range of caverns that can be used such as salt, depleted gas reservoirs, aquifers and rock.

Capex, O&M costs and performance data from nine key references were converted to 2017 Australian dollars, however due to the wide range of data and limited data for some parameters, the 'difference squared' methodology was of limited use in developing the cost model. Instead, the model is mainly based on figures provided by industry representatives during stakeholder consultations, along with some interpretation of the reference data.

The base hydrogen storage system was a 30 MW electrolyser, 1000 hours of salt cavern storage and a 30 MW combined cycle hydrogen turbine. For the scaling power law, available data combined with information provided by a key manufacturer indicated an exponent of 0.7 was a plausible model. The main source of information on underground hydrogen storage is a Sandia reference (Lord *et al.*, 2011), which is summarised in Figure 43.

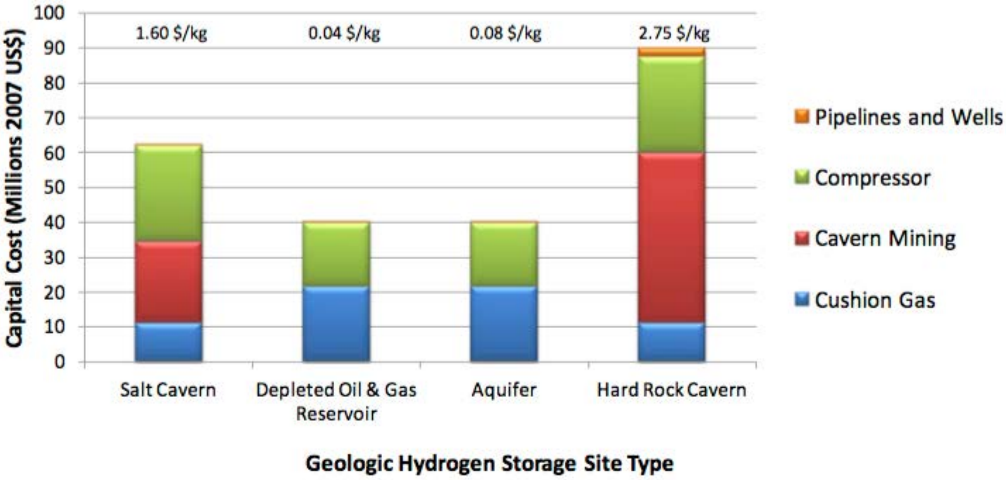


Figure 43: Underground hydrogen storage alternatives cost breakdown (note Hard Rock Cavern cost estimates do not include steel liner)

Analysis of the salt cavern option adjusted to AUD 2017 indicates a very low cost of \$600/MWh_f. This proves to be a very cost-effective approach to the storage of energy. It is worth noting that hydrogen also provides the potential option of using the existing natural gas transmission pipeline assets. These pipelines can inherently contain considerable stored energy (a few days of average load) due to the pressurisation of the internal volume. Up to around 15% hydrogen could be stored in this way without modification to the natural gas systems.

The final conversion step for a hydrogen-based system is assumed to be a combined cycle gas turbine plus steam turbine system. The commercially available *Gas Turbine World Handbook* (Pequot Publishing, 2014) has a comprehensive cost data set for such systems globally. The handbook also provides a close curve fit of specific cost to size that is:

$$\$/kW = (3.2x10^4) \times (kW^{-0.3}) + 154$$

The formula has been suitably adapted as the cost model for this study. Note that an exponent of -0.3 for a specific cost is equivalent to an exponent of 0.7 for total cost, exactly matching the 'seven tenths' rule for hardware of this nature.

It is also worth noting that existing turbine systems could potentially burn a mixture of hydrogen and natural gas, or even be retrofitted to pure hydrogen combustion at much lower cost than a new build system.

B.3. Inherently dispatchable

B.3.1. Concentrating solar thermal

CST systems use of mirrors to focus direct beam solar radiation to smaller areas and allow high temperatures of many hundreds of degrees to be reached. They are suitable for operation in large thermal power stations as well as advanced thermochemical processes and industrial process heat (Lovegrove *et al.*, 2012).

There are four main CST technologies: linear Fresnel, parabolic trough, heliostats with tower, and paraboloidal dish. While parabolic trough plants have the longest track record of operation and account for the bulk of systems deployed, tower plants are emerging as a lower cost option due to the higher temperatures and efficiencies and more cost-effective energy storage that has been achieved. Linear Fresnel and dishes have their own advantages and are also being actively pursued.

CST power systems almost exclusively use steam turbines to generate electricity, in a similar manner to coal fired power stations. They thus provide synchronous generation with inherent inertia. There are advanced power cycles that are the subject of R&D activities and may come into play in the future.

CST plants are complex integrated systems made up of a series of subsystems, as illustrated for the particular case of a molten salt tower plant in Figure 44.

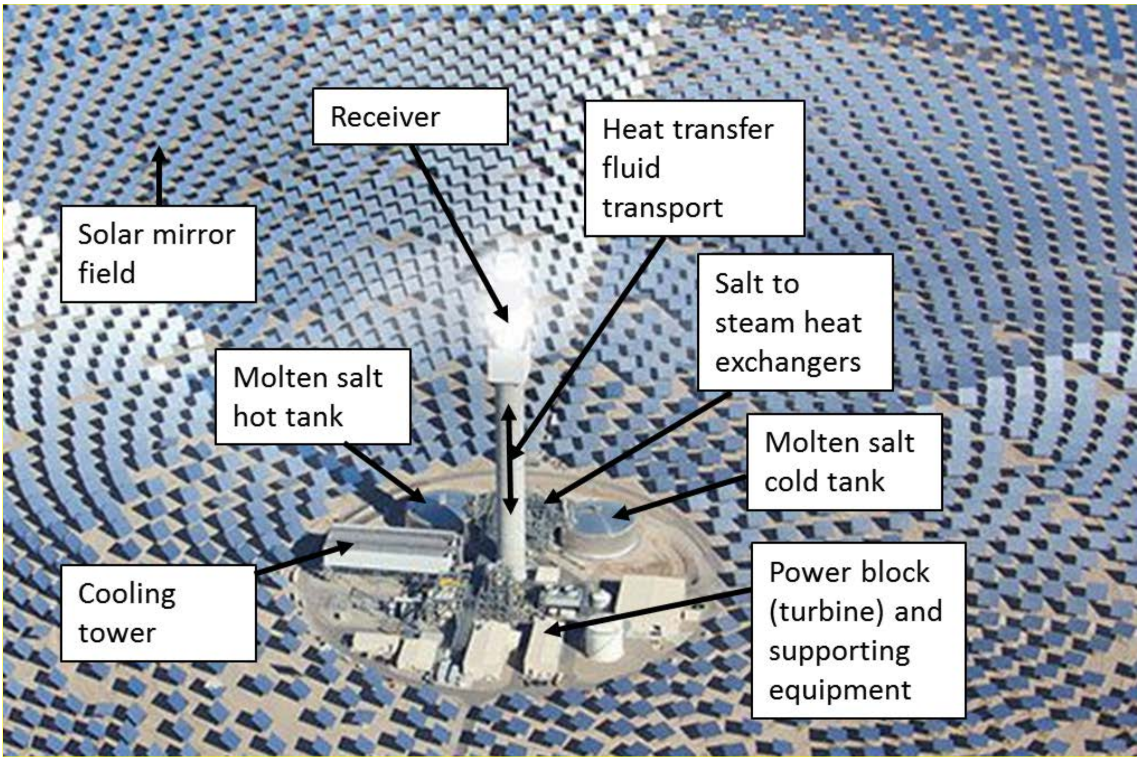


Figure 44: Subsystems in a molten salt tower CST plant

Key subsystems are:

- the mirror (heliostat) field that gathers solar radiation and directs it to a focal point by tracking the sun during the day
- the receiver that intercepts the radiation and converts it to high temperatures
- the heat transfer fluid system that takes heat from the receiver and transports it to storage and/ or power block
- the thermal storage subsystem, that is typically based on two tanks of liquid salt but can use other processes
- the power block and associated equipment, typically based on a steam turbine.

CST power plants are attracting increasing interest due to their ability to store large amounts of energy and provide dispatchable electricity supply. The current industry standard approach is to use a use a mix of molten nitrate and potassium salts as a heat storage medium that is moved between a 'cold' tank at around 250ºC to a 'hot' tank at 400ºC or 600ºC depending on the concentrator type.

Technology status

Initial large-scale deployment of CST began in the USA in the 1980s, and those original plants continue to operate. The industry had a renaissance from 2005 and has experienced strong growth over the past decade. Total installed capacity is around 5 GW as shown in Figure 45. The majority of recent and new CST plants incorporate thermal storage of around 6–10 hours duration.

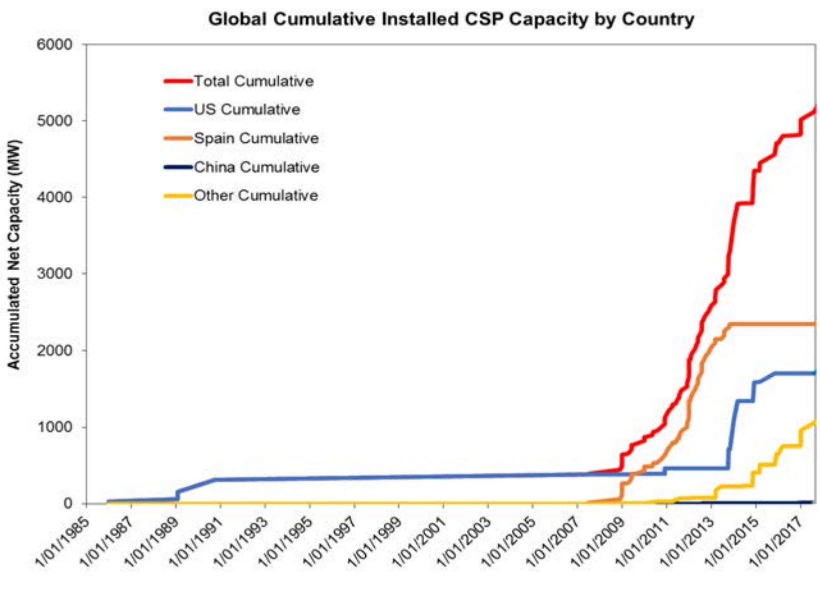


Figure 45: Concentrated solar deployment history

Australia is yet to complete a utility-scale CST plant. The largest installation to date is the Sundrop Farms tower system located near Port Augusta in South Australia. The plant is 36 MW_{th} with just 1 MW_e of electricity generation and most of the energy providing heat for desalination and heating of the greenhouse installation. SolarReserve has a well-developed proposal (the Aurora project) for a

135 MW_e tower system with eight hours of storage for a site north of Port Augusta (Evans, 2017). As at the end of 2017, this project has secured an offtake agreement and development approval from the SA government and an as yet uncommitted offer of $110 million investment from the Federal government. It appears likely to be Australia's first large-scale CST system.

Costs

ITP previously carried out a comprehensive study on the potential for concentrating solar power in Australia (Lovegrove *et al.*, 2012). The study compiled all globally available public cost data for CSP and supplemented it with key confidential inputs from major players in the field. This data was normalised, averaged and then deconstructed to assemble a subsystem-based cost model.

Subsequently, a technology neutral cost model was used to produce a set of technology specific cost inputs for the well-known NREL System Advisor Model (SAM). In doing so this highlighted a newly emerging industry view that a tower system with direct salt heating and significant hours of energy storage offered the lowest LCOE. This view has strengthened over time, and accordingly a salt tower system is adopted for this study as the proxy that establishes the current best practice cost for CST.

More recently, ITP has carried out extensive analysis of salt tower costs for Abengoa (Lovegrove, Jordan and Wyder, 2015). Abengoa had carried out a detailed bottom up engineering study of a first pilot-scale 30MW_e salt tower plant sited at Perenjori in WA. As such it is probably the most detailed specific cost estimation study that has been carried out for CST in Australia. ITP's work built on the Perenjori study results by scaling them to a full sized *n*th-of-a-kind system.

Seven external sources of information have been accessed to develop a CST cost model for this study:

- IRENA (IRENA, 2017) has produced a comprehensive study that offers installed cost data in a globally generic manner for all the key renewable energy technologies including CST. IRENA is a reputable source that has presumably surveyed industry sources in a reasonably comprehensive manner. The extent to which it has captured a correct and up to date view is not entirely apparent.
- NREL (NREL, 2017) has also produced a comprehensive dataset on CST costs. NREL is a similarly reputable source that has presumably surveyed industry sources in a reasonably comprehensive manner. Again, the extent to which it has captured a correct and up to date view is not entirely apparent.
- SolarReserve has publicly revealed a capital cost ($650 million) and predicted annual generation (495 GWh) for its Aurora 135 MW salt tower system planned for Port Augusta in South Australia. This is the most up to date and directly relevant cost data point available for Australia. The project has not yet reached financial close so the cost prediction carries this level of doubt. Only an on budget completion of the project will completely confirm it.
- CO2CRC has published the *Australian Power Generation Technology Report* (CO2CRC *et al.*, 2015), which includes cost data for CST and is in wide circulation as a definitive source in Australia. The report appears to be largely based on a conservative view of costs due to its reliance on older published data sources and so it effectively lags behind other published data. It is also now two years old.

- Price (Price, 2017) has recently published a US-based study that involved detailed bottom up cost estimation of a tower plus salt system carried out by Sergeant and Lundy. This is a strong and recent data point for US conditions. It can be assessed as being likely more conservative than the price that might be offered by an OEM under an aggressive bidding environment.
- The NREL SAM (Blair *et al.*, 2014) contains cost calculations within its default models for technology configurations including tower with molten salt. NREL attempts to update these according to its understanding of industry status. While the NREL calculations may lag actual achievable costs to some degree, its model is particularly useful for understanding the relationship of installed cost to plant configuration.
- ARENA's request for information (RFI) on CST projects elicited 30 responses from a range of experienced players, including two that offered a view on installed costs and many that offered a view on LCOE.

The model developed to identify CST costs for this study uses:

- a coefficient that determines the cost of the solar field plus tower and receiver on a $/kW basis subject to a power law size scaling
- a coefficient that determines the cost of the thermal storage system on a $/kWh basis subject to a power law size scaling
- a coefficient that determines the cost of the power block and all balance of plant on a $/kW basis subject to power law size scaling
- a multiplier applied to all direct contributions to cost that covers indirect costs as a proportion.

B.3.2. Geothermal

Geothermal energy is utilisable heat from within the earth's crust, sourced by bringing the heat to the surface in a fluid (steam or water). The fluid may occur naturally in a sub-surface reservoir or may have to be injected from the surface. Hot sedimentary aquifer (HSA) geothermal approaches access relatively low (up to 95ºC) temperature sources with natural permeability, whereas 'hot dry rock' or engineered geothermal systems (EGS) exploit the heat stored in rocks deep beneath the earth by fracturing the rock to create permeable reservoirs. Geothermal energy systems rely on drilled wells to access heat and, once developed, can produce heat 24 hours per day on demand (Huddlestone-Holmes, 2014).

Technology status

In Australia, the outlook for the technology for electricity generation is muted. The small-scale Birdsville geothermal power station in Queensland, commissioned in 1992, remains the only established plant. A new 200 kW system is currently being constructed in Winton. There are niche applications for HSA being explored that employ organic Rankine cycle engines to support uses in additional to power (e.g. town water), accessing water at 85-95ºC in a similar configuration to the Birdsville power station. The region of the Great Artesian Basin has the potential to support many such systems in inland regional Australia. For EGS, activity in resource exploration and project development has declined from the levels of the mid-1990s to early 2000s. Lack of success with developments despite considerable effort, technical failures and the location of resources distant from existing transmission have stymied developments in EGS. There remains potential for international project developments in EGS (e.g. Forge project in USA), which could restart the industry globally if these were to experience success.

Performance

Most of the global geothermal resources currently exploited for power generation are convective hydrothermal systems (where the heat is carried upwards by fluids). However, the Australian continent lies in a geological region that does not have these convective heat flow regimes. Instead, Australia's geothermal resource is characterised by conductive processes, for which global experience with power stations at utility-scale is virtually non-existent, and with operational plants only a few megawatts in scale.

With a few exceptions, the focus of developing geothermal resources suitable for electricity generation in Australia has targeted reservoir temperatures over 150°C. There are four projects that have drilled to reservoir depths in Australia: Geodynamics' Innamincka Deeps, Petratherm's Paralana, Origin Energy's Innamincka Shallows and Panax's Penola. The first two were targeting EGS resources while the second two were targeting natural reservoirs. Only the Innamincka Deeps project with six wells progressed beyond a single well (drilled to a depth of 4421 metres). In all cases, the temperatures found were close to expectations. However the flow rates have been lower than expected, particularly for the natural reservoirs. The Innamincka Deeps project ran in standalone mode from June 2013, with availability exceeding 75%. The maximum well head temperature achieved was 215°C with a flow rate of 19 kg/s and the plant generated approximately 650 kW_e gross.

A preferred geothermal energy resource, from a cost and performance perspective, would have a desirable combination of flow rates of fluid and sub-surface temperature. In general, temperatures increase with depth in most geological settings, with shallow resources being lower risk. For HSA, the extraction rate achievable is limited by the ability of the aquifer to replace the extracted flow, determined by both the permeability/porosity and the thickness of the reservoir. Pumping requirements will increase with increasing well depth and decreasing well diameter. Extraction rates and pumping loads have a significant impact on project economics. For EGS, levelised costs rise rapidly for smaller annual heat requirements as the fixed cost of a single pair of wells must be amortised over progressively lower energy demand. Applications requiring less than around 20,000 GJ p.a. (equivalent to a 634 kW_{th} continuous load) are unlikely to find the approach attractive in the near to medium term. In other cases, if a process temperature below 100ºC can be used and an aquifer is available at less than 1500 metres depth, this appears to be reasonably attractive.

Costs

A lack of global precedents for analogous plants and limited Australian data means there are limitations on this study's capacity to assess technology performance and costs. An in-depth study by ARENA (Australian Renewable Energy Agency (ARENA), 2014) provides the most authoritative source, however the study provides a generous outlook for EGS potential and is based on highly favourable assumptions on flow rates and well success rates.

For the ARENA study, the NREL SAM (Blair *et al.*, 2014) was used to determine performance and costs for seven scenarios that are representative of the range of resources that have been targeted for Australia in 2020 (2014 dollars). AETA inputs (Bureau of Resources and Energy Economics,

2012) were used for validation. The seven scenarios use assumptions of the technical performance of geothermal energy systems that have yet to be demonstrated for conductive geothermal resources in Australia, and therefore the costs of drilling should be regarded with a high level of uncertainty due to the small size of the drilling market, lack of published data and variability of market conditions.

NREL has undertaken recent modelling that assumes significantly higher capital and O&M costs than the SAM modelling used for ARENA and the AETA model (NREL, 2017). The more recent NREL costs are based on flash steam plants, which are the most common type of geothermal power generation plant in operation but unlikely to be used in Australia due to the high- water requirement for reservoir injection.

SAM has a much more detailed model of geothermal systems than that used in the AETA model, and key parameters were chosen to ensure they were consistent with the AETA 2012 model. These were total power, installed capital costs, operating costs and maintenance costs. The input parameters for SAM were:

- **exploration cost**: $2.0 million plus the cost of drilling two confirmation or test wells (at 20% more than the production wells) per project
- **reservoir characteristics**: resource temperatures of 150-250ºC with a thermal gradient in the order of 40-50ºC per kilometre, resource depth of 2500-5000 metres, and distance between injection and production wells of 1000 metres
- **flow rate**: natural reservoirs of 100 kg/s, EGS reservoirs of 40-80 kg/s
- **drilling costs**: $7.2 million to $11.2 million per well for HSA and $11.2 million to $28.8 million per well for EGS, with additional costs associated with drilling ‘trouble’ included in the 15% contingency applied to the overall capital costs for the project; also contingent on all wells being successful, ratio of injection wells to production wells of 1, one of the two confirmation wells being converted into a production well, well head and brine reticulation costs of $2.0 million per well, and reservoir stimulation costs of $1.0 million per well for EGS resources
- **thermal drawdown**: annual decline rate of 0.2% for natural reservoirs and 0.3% for EGS reservoirs, maximum temperature to decline before replacement of well field of 20°C for initial resource temperatures equal to or under 150°C and 30°C for initial resource temperatures over 150°C
- **power plant operating capacity factor**: 83% and capital costs of power plant of $2500/kW for resource temperatures ≤ 180°C, and $2000/kW for higher resource temperatures
- **O&M costs**: fixed rate per installed capacity of $210/kW/year
- **Contingency**: 15% on all capital costs
- **Cost of finance during construction**: not considered.

The SAM modelling results for overnight capital costs for two HSA scenarios range from $9273/kW to $10,077/kW and for five EGS scenarios from $10,754/kW to $19,532/kW (2014 AUD). The cost of drilling is the largest component, ranging from around 42% for HSA and 48% to 65% for EGS, with the differences between HSA and EGS reflecting the assumption that drilling in sedimentary rocks will have a lower cost than drilling into crystalline basement. The second largest component is the cost of the power plant, ranging from around 28% for HSA and 17% to 21% for EGS, reflecting higher costs for HSA due to the lower resource temperature.

B.3.3. Bioenergy

Biomass is organic matter originally derived from plants, which is not fossilised (such as coal), and can be used to provide heat, electricity, transportation fuels, or as a chemical feedstock. Bioenergy is the oldest provider of energy and still the greatest contributor to global renewable energy, providing approximately 10% of global primary energy consumption. While most of that is traditional biomass used for cooking and heating, modern biomass provides 2% of global electricity (REN 21, 2017). In Australia bioenergy provides just 1.5% of total electricity generation, nearly all from bagasse generators at sugar mills. However some countries, for example, Germany, the UK and Brazil, provide closer to 10% of electricity from bioenergy. Worldwide electricity generation from biomass was 504 TWh, up from about 325 TWh in 2010, with capacity increasing from about 58 GW to 112 GW in the same period (IRENA, 2012; REN 21, 2017).

Bioenergy is essentially renewable and carbon neutral, provided the biomass source is regrown. Carbon dioxide released during energy conversion circulates and is reabsorbed in equivalent stores of new biomass through photosynthesis. However bioenergy is complex, with multiple feedstock options and multiple energy conversion technologies, with significantly different attributes and costs.

Technology

Most bioenergy conversion occurs in traditional gas turbines or steam turbine driven generators. Accordingly, its value streams include all those associated with traditional fossil fuel generation, including electricity and heat, firm capacity and inertia. When electricity is generated from gas, value streams also include flexible response with rapid ramp rates. In addition, bioenergy plant frequently provide effective waste treatment, which is often the primary driver for the plant. There may be considerable co-benefits in the case of some bioenergy feedstocks, ranging from salinity control to shelter belts for livestock. On the other hand, there are almost invariably alternative uses for bioenergy feedstocks, and bioenergy use can in some cases compete with food crops.

Energy conversion methods range from well-proven and established direct combustion technologies to emerging technologies to convert bioenergy into liquid fuels. The most common established technologies are direct combustion to drive steam turbines, gasification combined with gas engines, and anaerobic digestion to produce biogas, which may be used in a conventional gas generator.

Materials that can be used as bioenergy feedstocks include agricultural residues, such as bagasse or straw; purpose grown energy crops, such as short rotation coppice (SRC); waste wood or sawdust from forestry operations; and organic waste streams from industry, livestock, food production, and general human activities. Feedstocks may be ‘wet’ (for example, manure, slurries or liquors), or dry, like wood chip or municipal waste. The bioenergy plant may receive feedstocks with no treatment other than harvesting and transport, or may also be the treatment plant in the case of many wastes. Alternatively, feedstocks may be dried and processed to produce a fuel with particular characteristics, such as wood pellets or briquettes.

Bioenergy is by its nature a dispatchable energy source, in the same way that traditional fossil fuels are dispatchable. Direct combustion uses the same conversion methods, burning a fuel and using the heat to drive a steam turbine, and bioenergy power stations can contribute like for like replacement, such as in the conversion of coal fired power stations to run on wood pellets, which has occurred in the UK. Anaerobic digestion produces a gas which may be used in any form of gas generator.

Plants range from small domestic systems to multi-megawatt power stations requiring several hundred thousand tonnes of biomass fuel each year. Although most of the plant that do not use processed fuels such as wood pellets are below 100 MW, many are in the 0.5 MW to 20 MW range as cost-effective transport distances for lower value fuels restrict the catchment area for the plant.

The use of bioenergy plants to reclaim energy from waste streams adds complexity, as effective management of the waste itself is frequently the driver for the technology, and the energy extraction is just one of the value streams arising. Thus, the plant will be sized and run according to the requirements of the waste management. While the fuel itself may have a zero or negative value, there may be a ‘gate fee’ for the waste treatment or alternative disposal costs.

This study has considered a limited range of bioenergy technologies and fuels, which are outlined below. It should be noted that each technology plus fuel combination will have its own costs and considerations.

Direct combustion may be used with multiple feedstock types, typically with a condensing steam boiler and steam turbine. Size ranges from several hundred kilowatts to hundreds of megawatts, although the median size of generation plant is around 15 MW (IRENA, 2015, figure 8.5). Combustion may be used with purpose grown energy crops, such as short rotation coppice crops, or with agricultural residues such as bagasse or straw. A material consideration is the alternative use for the waste.

Combustion may also be used for mixed waste streams such as municipal solid waste. In this case the capital expenditure will be dominated by the waste handling and treatment, as the waste requires sorting to extract the organics and may require some material diversion for recycling. The plant also will require considerable effort on the flue gas treatment, which is more complex with a mixed feedstock. Gate fees for the waste treatment are likely to be required to provide a return on investment.

Costs are presented for a combustion biomass plant combined with purpose grown short rotations coppice (SRC) woody crops based on mallee. The supply chain for this fuel takes some time to set up, and it applies to relatively decentralised power plants, with a maximum size of around 50 MW. There are potentially significant co-benefits including local employment opportunities, salinity control, biodiversity improvement, and the provision of agricultural shelter belts.

Wood pellets offer an interesting alternative, particularly as there are international instances of coal fired power stations being converted to run on wood pellets. However, in the absence of strict environmental regulation, there is the danger that wood pellets may be sourced from unsustainable forestry, and they do not bring the co-benefits available from short rotation woody crops. While it would be possible to establish a large-scale Australian wood pellet industry, this is likely to be more costly than biomass from SRC.

While conversion efficiencies vary according to the characteristics of the fuel (in particular its moisture content) and the plant itself, typical efficiencies range from about 22% for agricultural residues such as bagasse to about 35% for oven dry wood or high quality pellets (for example, Stucley *et al.*, 2012; ARUP, 2016; Clean Energy Finance Corporation and Hancock Renewable Energy Group, 2017). Note that these conversion efficiencies are for electricity only, and are considerably improved if the heat is used in a cogeneration plant.

Anaerobic digestion is the breakdown of organic matter by bacterial action in the absence of oxygen, which produces methane. AD is often primarily selected as waste treatment option, to be installed where the waste occurs. For example, where sewage treatment is anaerobic, the installation of capture and generation equipment is almost always cost effective, and the electricity is generally used entirely on site. Anaerobic digestors can be used to treat waste streams in a wide range of industries from food and beverage to livestock. In most of these cases, the fuel would otherwise attract a treatment fee, and the energy will largely be consumed on site.

AD occurs in landfill sites, where methane is produced from the organic element of the waste, and requires control to prevent explosion. In this case energy generation is the alternative to flaring the gas. However anaerobic digestors are more commonly an active waste management strategy. The digestor element may require little additional expenditure, for example it may only require fitting a cover to an existing waste treatment lagoon to capture gas, or may require the installation of a purpose made tank where digestion and gas capture occurs. Anaerobic digestion may also be used at a central waste processing site for liquid wastes, such as slurries from livestock or food and drink industries.

Efficiencies for anaerobic digestion are essentially the conversion efficiency of the gas engines: typically 34% (International Gas Union, 2012)[14].

Costs

it should be noted that each combination of technology plus fuel will have its own costs and considerations.

The capital cost and O&M cost for a generic bioenergy combustion plant and a generic AD have been derived by using the methodology described in Section 3.1 to get the best fit from eleven and five data points respectively. Several data points were disregarded in each case. Fuel costs have been derived by averaging the data points from those same sources, and the cost for additional storage has been indicatively calculated.

The data used to derive the costs for combustion plant are shown in Table 26, for AD in and for fuel and storage costs in Table 28.

In order to separately estimate capacity and energy costs, the assumed cost and amount of storage in each plant type has been used to separate the storage capex from the capex associated with the fuel store. In the case of AD, this has been further disaggregated to isolate the digestor from the engine costs. This is to allow for the use of an AD plant in a peak configuration by increasing gas

[14] Note that the thermal conversion efficiency does not impact the cost calculation, as modelling inputs are available in electrical capacity costs.

storage and the size of the engine. The gas engine and associated costs have been assumed to account for 18% of the capital costs (Mott MacDonald, 2011).

Plant costs

In the case of the combustion plant, two gasifier plants are excluded from the analysis along with two data points from the 2012 Australian Technology Assessment (Bureau of Resources and Energy Economics, 2012), which has been superseded by the 2013 update. Two feasibility studies for chicken litter combustion and feedlot manure are given a reduced weighting, as the focus of the studies was primarily on the waste management aspects. Two studies are given a weighting of two as they result from a comprehensive data review, one in the UK and one in the US (Arup, 2016; U.S. Energy Information Administration, 2017); this gives them equivalent weighting to the two Australian studies and the IRENA global review, which have two data points each.

In the case of the AD plant, less data points are available and only five contribute to the modelled value for capex. The UK study (Arup, 2016) and the global overview (IRENA, 2015) are each given a weighting of two, as they average a large number of plant, while the two feasibility studies are weighted at 0.5 each. One stakeholder interview gave detailed costs for a centralised facility treating liquid effluent.

Table 26: Data sources used to derive model capital cost and O&M for bioenergy combustion plant

DATA SOURCE, COUNTRY	DESCRIPTION	POWER MW	O&M FIXED % of Capex	CAPEX(1) Au m$/ MW	WEIGHTING
ADOPTED MODEL	**Direct combustion: boiler plus steam turbine**	**15**	**3.6%**	**$4.91**	
(Stucley *et al.*, 2012) Australia	Generic, steam turbine using bagasse or woodchip	5	5.7%	$5.40	1
(Stucley *et al.*, 2012) Australia	As above	20	5.4%	$3.15	1
(Stucley *et al.*, 2012) Australia	Generic, gasifier package	0.5	5.4%	$8.10	0
(IRENA, 2015) OECD	BFB/CFB boiler; average of large number of plant, power rating median from US and Europe	15		$4.19	1
(IRENA, 2015) OECD	As above for stoker boiler	15		$5.20	1
(IRENA, 2015) OECD	As above for gasifier	15		$4.07	0
(McGahan *et al.*, 2013) Australia	Darwalla, Chicken litter, combustion	7.5	13%	$16.00	0.5

(Bureau of Resources and Energy Economics, 2012) Australia	Reference plant, boiler and steam turbine, wood waste	2		$5.00	0
BREE 2012 (as above)	As above	20		$6.00	0
(Bridle, 2011) Australia	Feasibility study, fluid bed combustor/boiler and steam turbine, feedlot solid waste	4.1	3.3%	$6.80	0.5
AETA Model_2013-2 (Excel) Australia	Generic, high pressure boiler firing stored bagasse, condensing steam turbine	32	3.1%	$4.00	1
AETA Model_2013-2 (Excel) Australia	Generic, high pressure boiler firing wood, condensing steam turbine	18	2.5%	$5.00	1
(Energy and Environmental Analysis and Eastern Research Group, 2007) US	Generic, stoker boiler, configured for power only	15.5	2%	$2.48	0
(US Energy Information Administration, 2017) US	Reference plant	50	2.9%	$5.04	2
(Arup, 2016) UK	Average of 7 dedicated bioenergy plant plus published sources, condensing boiler	22.9	2.2%	$5.52	2
(Kallis, 2016) Australia	Yorke, biomass	15		$6.00	1

Note 1) Including 30 days storage assumed for the plant

Table 27: Data sources used to derive model capital cost and O&M for anaerobic digestion plant

DATA SOURCE, COUNTRY	DESCRIPTION	POWER MW	O&M FIXED % of Capex	STORAGE AU$/MWh	TOTAL CAPEX (1) Au m$/ MW	WEIGHTING
ADOPTED MODEL	**Anaerobic digestor**	**2.5**	**5.2%**		**$5.10**	
(Arup, 2016) UK	Average of 14 AD plant	2.3	10.8%		$6.12	2
(IRENA, 2015) OECD	Average of large number of AD plant	0.5	3.7%		$5.77	2
(McGahan *et al.*, 2013) Australia	Feasibility, centralised AD digestor for poultry litter	4.6	5.7%		$6.25	0.5
(Bridle, 2011) Australia	Feasibility, AD of feedlot liquid effluent, based on building new contact digestor and gas engine	0.3	3.1%		$21.91	0.5
AETA Model_2013-2 (Excel) Australia	Generic, landfill gas reciprocating gas engine	1	5.0%		$3.00	0
(Oliff, Sheva and Barber, 2012) Australia	Generic, reciprocating gas engine	0.007	0.7%		$20.40	0
Stakeholder interview, Australia	Centralised facility for AD of food waste	1		36,000	$6.2	1

Note 1: Including 1.5 hours storage

Fuel costs and storage costs – combustion plant

Each technology and feedstock combination will result in different costs. While the capital costs of the technology are relatively easy to estimate, the fuel costs vary enormously from negative in the case of some wastes, to significant in the case of purpose grown energy crops.

Establishing supply chains for bioenergy fuels is a major obstacle to the installation of a bioenergy power plant. Without the demand for feedstock the supply chain cannot be established, and without the supply chain, power station operators cannot take the risk of developing the plant. While the economics appear to be reasonable if co-benefits are taken into account, the establishment of a short rotation coppice mallee industry has so far been elusive in Australia. This has to some extent been overcome by the availability of wood pellets, which are now an internationally traded fuel, but these may not be the cheapest bioenergy option.

Fuel costs typically account for between 20% and 50% of the LCOE from bioenergy power-only plant (IRENA, 2012), excluding those cases with a negative fuel cost. Table 28 shows the data used to produce average fuel costs per MWh.

For bioenergy plant where fuel must be delivered, that is, the feedstock is not a waste arising on site, the storage built for the plant will vary according to the supply chain logistics. Stucley *et al.* (2012) consider that most bioenergy plants would have sufficient storage for approximately 10% of annual usage, while another author put the minimum at 20 days (Rentizelas, 2016). For the purpose of this modelling exercise, it is assumed that 30 days' usage is included within the plant capex. This amounts to approximately 8% of the capex associated with feed handling, and 5% of the overall plant cost[15].

With some considerable caveats, an indicative storage cost may be calculated for these plant, with the assumption that the operator might wish to ensure a larger buffer in case of supply chain disruption. For comparison, coal-fired generators generally keep a minimum of three months' fuel on site.

An indicative storage cost has been calculated for 'loose' feedstock (e.g. bagasse, and straw) using a maximum cost per tonne of AU$19.95[16], which is for enclosed storage with a crushed stone floor (Energy and Environmental Analysis and Eastern Research Group, 2007). A storage cost for wood pellets has been calculated using CSIRO's estimate of $30 per tonne for enclosed bolted steel grain silos[17] (CSIRO, 2001). The storage requirement per MWh has been calculated from the GJ/tonne and the efficiency:

$$\frac{Tonnes}{MWh} = \frac{1}{\frac{GJ}{tonne} / \ efficiency} \ x \ 3.6$$

[15] The percentages are calculated using US$15 per tonne to build storage sheds
[16] Converted from US$ using an exchange rate of 1.33
[17] Wood pellets have very similar density to barley

There are many caveats that must be placed on the calculation of storage costs, as the situation of every bioenergy plant and each fuel type will be different. Storage management is complex, and issues may include deterioration through composting, self-ignition, fire risk and dust, to name just a few. There is guidance available and literature on optimising storage for different types of feedstock, however each bioenergy plant will need to construct storage appropriate to the particular feedstock and the requirements for secure supply.

Note that no allowance has been made for deterioration, which may be significant for some feedstocks, but will be highly dependent on the exact storage conditions and the characteristics of the feedstock. For example, some research shows wood chip degradation can occur very quickly at first (over days), and then slow down considerably.

Table 28: Data sources and values adopted for feedstock cost, energy content, and cost of storage

	Fuel type	Fuel cost $/kWhe	Conversion efficiency	Fuel cost min – max $/GJ	Fuel cost data point A$/GJ	Moisture content	GJ /tonne	Tonnes per MWhe	Cost per MWh storage
ADOPTED	**Bagasse**	**0.013**	**22%**		**0.77**		**8.8**	**1.9**	**37.27**
ADOPTED	**Wood pellets**	**0.114**	**35%**		**11.1**		**17.5**	**0.6**	**17.63**
ADOPTED	**Woody energy crops (SRC)**	**0.073**	**26%**		**5.3**		**10.00**	**1.38**	**27.62**
ADOPTED	**Straw**	**0.083**	**25%**		**5.7**		**14.8**	**1.0**	**19.40**
Storage note: in the model it is assumed that plant CAPEX includes 30 days storage for combustion plant									
DATA SOURCES									
(IRENA, 2015) OECD	Agricultural residues	0.066	22%	1.73 - 4.33	4.0	20-35%			
(Stucley *et al.*, 2012) Australia	Bagasse	0.002	22%	0 - 0.2	0.1		8.76	1.87	37.27
AETA Model_2013-2 (Excel)	Bagasse	0.014	22%		0.8				
(Crawford *et al.*, 2012)	Bagasse	0.011	22%	0.6 – 0.8	0.7				
(IRENA, 2015) OECD	Forest residues	0.037	25%	1.3-2.61	2.6	30-40%			
(McGahan *et al.*, 2013) Australia	Poultry litter	0.072	25%		5.0	dry	10	1.44	28.73

(Crawford *et al.*, 2012)	Wood waste	0.013	27%	0.4-1.5	1.0				
AETA Model_2013-2 (Excel)	Wood waste	0.020	27%		1.5				
(IRENA, 2015) OECD	Wood waste	0.027	27%	0.5-2.51	2.0	5-15%			
(Arup, 2016) UK	Wood waste	0.018	27%			29%	12.5	1.07	21.28
(IRENA, 2015) OECD	Woody energy crops	0.105	26%	4.51-6.94	7.6	10-30%			
(Stucley *et al.*, 2012) Australia	Woody energy crops (SRC)	0.073	26%	4.2-6.3	5.3	50%	10	1.38	27.62
(Clean Energy Finance Corporation, 2017)	Wood pellets	0.114	35%		11.1		17.5	0.59	17.63
(Kallis, 2016)	Straw	0.083	25%		5.7		14.8	0.97	19.40

Fuel costs and storage costs – anaerobic digestion plant

Anaerobic digestors almost invariably use a waste product as fuel, bestowing that fuel with a negative cost equivalent to the avoided treatment cost or the gate fee in the case of a centralised AD facility which is accepting liquid wastes. However for this study the cost is assumed to be zero.

Many AD plant provide waste treatment for an industrial operation, using a large proportion of the electricity generated on site. The bioenergy operation is tied to the time the waste is produced, which is likely to correlate to when the plant is active and electricity prices are high, leading to electricity demand behind-the-meter. There may be limited ability to store gas that arises from the digestor, so the plant may be required to operate more or less in sync with the digestor. This is unlikely to be an issue if most of the electricity is used on site, as digestor operation usually correlates with demand. However, for centralised plant where electricity is exported, there may be a need to extend the ability to store gas in order to provide the option to turn the generator off for periods of time when demand is low but the waste stream is still active. Thus the requirement for storage is to turn the generator off or down rather than to extend generating hours.

B.4. Demand response

The cleanest energy is the energy not used, and demand response has a long history in Australia, particularly through the aggregation or direct load control of commercial and industrial customers by electricity retailers and networks, or via a range of energy management and solar companies. The control technologies employed in Australia and internationally have evolved in sophistication over time, from spreadsheets and phone calls suitable for managing peak demand events, to real-time dispatch systems capable of fast response to contingency events. Hundreds of megawatts of commercial and industrial demand response are an important resource when aggregated for the market, as well as when individually contracted, with a key role in avoiding unplanned outages.

It is a natural step to coordinate demand response with VRE generation to produce a dispatchable net result. Aggregating demand response from customer loads alone can smooth dips in VRE output, but peaks in generation in excess of total load may still have to be dealt with by curtailing generation, which reduces the capacity factor and increases the cost of VRE. Depending on the relative costs, therefore, it may be desirable to include energy storage alongside managed load so that peaks in VRE generation can be shifted and not curtailed.

Presently, customer energy storage using batteries is marginal for commercial customers except when they are exposed to high demand charges, such as those that apply in Queensland at the time of writing. Thermal energy storage might be available at some customer sites. On the other hand, as noted in Section 3.2.3, residential battery storage is growing rapidly and becoming common. Reposit Power is one of the Australian market leaders in residential demand side integration focussed on energy storage with a technology-agnostic approach. This company exemplifies mass-market aggregation of kW-scale resources to MW-scale services offered to multiple parties.

Reposit Power has a ‘benefit stacking’ business model. In addition to receiving the direct benefits of behind-the-meter applications such as solar self-consumption, customers with Reposit’s control-enabled batteries can switch to a retail offering that includes GridCredits, representing revenue from network and market services. This significantly reduces the payback time of the batteries while giving customers the opportunity to participate in electricity markets and help the system to integrate more renewable energy. Benefit stacking means that the direct cost of energy storage for any one application is less, potentially much less, due to cross-subsidy by many other applications. At a system level the costs of supplying the network service are the same, or slightly greater due to the overhead of aggregation and complex dispatch optimisation, so it is a matter of how those costs are allocated among stakeholders.

There is emerging competition in the residential demand side aggregation market. GreenSync has a broader remit than Reposit Power, aggregating residential loads as well as energy storage, and has successfully partnered with United Energy in response to a regulatory investment test to defer or avoid distribution network augmentation (under the Regulatory Investment Test for Distribution, or RIT-D process). They recently launched the deX trading platform for distributed energy in association with a wide range of industry partners. GreenSync is also a partner in a prominent project with AusNet Services, which recently islanded a network segment so that 17 customers operated for a period of time as a mini-grid, sharing residential solar and storage in place of the grid supply.

A range of DR options were proposed to ARENA and AEMO in response to their call for solutions to operate under the Short Notice RERT mechanism beginning at the end of 2018 (Silkstone, 2017). As discussed in section 4.7.2.

The Rocky Mountain Institute (Bronski *et al.*, 2015) has examined the value of shifting demand in four specific cases under different tariff structures in the US. The Institute modelled a threshold cost for shifting load and the potential for four major household electricity loads (air conditioning, electric hot water, electric dryers and electric vehicle charging) to be time shifted within constraints and operating requirements, with 7kWh/2kW battery storage also modelled as a point of comparison. Savings from shifting to low cost periods of energy were analysed with respect to specific cost drivers for customers depending on their tariff structures (avoided grid purchases, peak demand, etc.) and costs were based on the net incremental capital costs of making each technology more flexible (e.g. installation of communicating and/or smart thermostat to air conditioning unit). The modelling assumed existing communications infrastructure was adequate (i.e. excluded advanced metering costs) and did not include overhead program costs of centrally managed demand response.

The tariff structure in the modelling most comparable to arrangements in Australia is the scenario in which the solar PV export tariff was set at wholesale energy costs. The modelling established flexible load as cost effective if less than $8/kW a month and found the cost-effective load types were air conditioning, electric vehicle and domestic hot water, with battery or electric dryers not cost effective at current hardware costs or utility rates.

In the scenario modelled, demand flexibility from cost-effective sources could increase onsite solar PV consumption from 64% to 93% (by reducing export) and deliver additional bill savings and accelerate PV grid parity by three to six years. The modelling was based on an additional $5 per month in fixed charges for customers owning PV, energy charges of $0.11/kWh and PV export of $0.03/kWh (with avoided cost compensation for PV export) and a PV array size of 4 kW (representing 35% of household demand).

An Australian study by Climateworks (2014) found that demand response could reduce peak industrial loads by 42% (3.8 GW) if a 20% to 30% reduction in electricity bills was offered. If the offer was a 5% to 15% bill reduction, about 1.7 GW was potentially available. The latter corresponds to the level of incentive currently provided for DR in Western Australia and in various international jurisdictions.

B.5. Other technologies

This study has limited its detailed analysis to a subset of technologies that are considered commercially advanced. The choice has some arbitrariness to it and the conclusions in no way are intended to preclude the idea that new technologies can and will play a role over the coming years. As well as many technologies in the RD&D phase, there are technologies that are at an early commercial stage but do not yet have either large deployment or large demonstrable growth in deployment that could make significant contributions in coming decades. These include:

- Compressed air: Stored in low-cost buffers (such as caverns) and then used in turbines to generate electricity on demand.
- Cryogenic storage: Also known as liquid air energy storage, where power is used to liquefy air that can then be stored for short or long-term use.
- Flywheels: Mechanical devices that harness rotational energy, which can be converted back to electricity.
- Supercapacitors and superconducting magnetic storage: Supercapacitors store electricity as electrostatic energy and are often combined with batteries; superconducting magnetic storage uses superconducting technology to store electricity efficiently.
- Biomass gasifiers: These provide an alternative pathway to combustion and steam turbine, as the feedstock is gasified prior to cleaning and used in a gas engine or turbine. The operation is more complex, the equipment is often sensitive to small variations in feedstocks, and gasifiers are not currently well established in Australia. Costs are similar to anaerobic digestion, although this may change as gasifiers become increasingly modularised.

APPENDIX C. NEM DISPATCH & SUPPORTING SERVICES

The National Electricity Market as it operates for Australia's east coast grid is a complex thing. There is a spot market for buying and selling electricity, eight markets for ancillary services and other mechanisms for trading services. This Appendix summarises key NEM principles. In parallel with the market, participants often 'contract ahead' in various ways against the spot price, meaning their net revenue or cost outcome is more stable than would result from a five-minute market alone.

A single real-time, five-minute platform, the National Electricity Market Dispatch Engine (NEMDE) is used by AEMO to manage the dispatch of energy and frequency control ancillary services (FCAS) in the NEM (Stedwell, 2017). There are nine markets, a single energy service and eight FCAS services. All offers can be revised up to the five-minute interval immediately preceding dispatch. Regional half-hourly clearing prices (the time weighted average of the six five-minute prices) are set for each market based upon the marginal value of the service.

The NEMDE solves for energy and FCAS dispatch in real time, which minimises the amount of reserve required by fully taking into account system conditions at that point in time. During periods of high or low demand, NEMDE may move the energy target of a scheduled generator or load to minimise the total cost of energy and FCAS to the market. This process of 'co-optimisation' is inherent in the dispatch algorithm.

Any technology that is able to demonstrate the ability to provide a particular FCAS service to the specified standards can register to provide FCAS.[18] Generators registered to provide FCAS provide offers for each FCAS service every five minutes in conjunction with their energy offers. FCAS providers are paid regardless of whether this capability is actually called upon over that period. This differs from the wholesale energy spot market where generators are only paid according to their actual dispatch.

In addition to the markets for the delivery of FCAS, AEMO purchases Network Control Ancillary Services (NCAS) and System Restart Ancillary Services (SRAS) under agreements with service providers. The following describes the market dispatch process used for energy and ancillary services.

C.1. Energy

NEMDE derives dispatch targets for all Scheduled Generators, Semi-Scheduled Generators, scheduled network services and scheduled loads after co-optimising the energy market with the FCAS market. Dispatch instructions are usually issued electronically via the automatic generation control (AGC) system or the AEMO Electricity Market Management System (EMMS) interfaces depending on the type of generating unit. AGC is relevant to the market dispatch of generating units on remote control.

[18] Wind and solar farms are not precluded from providing FCAS, they could provide downward response and in future, with control technologies, rapid upward response.

Dispatch of semi-scheduled wind and solar generating units depends on outputs from the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). SCADA inputs from generating units are used to produce forecasts of 'unconstrained generation' in AWEFS or ASEFS, which are used in place of generator unit availability normally provided by a generator as part of the bidding process.

The NEMDE dispatches semi-scheduled generation based on bid information and the 'unconstrained generation' in AWEFS/ASEFS subject to the setting of the semi-dispatch interval flag. Semi-scheduled generating units will receive semi-dispatch interval flag status and dispatch instructions via the AEMO EMMS interfaces. If the semi-dispatch interval flag status is set to TRUE, the unit is subject to the conformance obligations as a scheduled generating unit. When the semi-dispatch interval flag is set to FALSE the semi-scheduled generating unit is free to generate at any level.

A Scheduled Generator, Semi-Scheduled Generator or Market Participant with generating units, scheduled network services and/or scheduled loads must provide up and down ramp rates, and maximum ramp rates.

C.2. Ancillary services

C.2.1. Frequency Control Ancillary Services

Frequency Control Ancillary Services (FCAS) are services required by a power system operator to ensure short-term supply and demand balancing throughout a power system. FCAS are used to maintain the frequency on the electrical system, at any point in time, to close to fifty cycles per second as required by the NEM frequency standards (AEMO, 2015; Riesz, Gilmore and Macgill, 2015).

This requires precise control of system frequency through operational reserves that can respond to disturbances. FCAS are characterised differently depending upon the types of power system events they respond to, the timeframe over which they respond, the manner in which they are activated and whether they act to raise or lower the power system frequency.

In general, FCAS can be sourced from anywhere in the NEM subject to relevant network constraints. If a region is islanded, FCAS can only be sourced for that part of the transmission network within the island. Under certain conditions FCAS will be sourced locally (for example, due to regional interconnector constraints or failure). The Tasmanian region is an exception; since Tasmania is connected to the mainland via a DC link, FCAS in that region is always sourced locally.

Of the eight separate real-time spot markets for the delivery of FCAS in the NEM, two are for the delivery of regulation (Regulation Raise and Regulation Lower), and six are for the delivery of contingency services (Raise and Lower for 6 second, 60 second and 5 minute response times).

Regulation services

Regulation services are continually used to correct the generation/demand balance in response to minor deviations in load or generation. Regulation services are controlled centrally from one of AEMO's two control centres. The regulation frequency control services are provided by generators on Automatic Generation Control (AGC). The AGC system allows AEMO to continually monitor the system frequency and to send control signals out to generators providing regulation in such a manner that the frequency is maintained within the normal operating band of 49.85 Hz to 50.15 Hz.

These control signals alter the megawatt output of the generators in such a manner that corrects the demand/generation imbalance.

The two types of regulation services are:

- Regulation Raise: Regulation service used to correct a minor drop in frequency.
- Regulation Lower: Regulation service used to correct a minor rise in frequency.

The regulation reserve requirement is determined dynamically in each five minute dispatch interval, based upon the accumulated deviation of the frequency over time (the 'time error'). The regulation requirement is adjusted each five minutes, responding directly as required to system variability and uncertainty and other factors that influence frequency (such as inertia).

If the time error is within the +/- 1.5 second band, regulation is set to 130/120 MW (raise/lower). If the time error is outside this band an extra 60 MW of regulation per one second deviation outside the band is added, with an upper limit of 250 MW. The exception in the Tasmanian region as it is connected to the mainland grid via a single DC link; its regulation requirement is set nominally to 50 MW.

The dynamic setting of the regulation requirement in this manner reduces the need for regulation reserves with additional reserves only procured when required.

Contingency services

Contingency services, while always enabled to cover contingency events, are only occasionally used. Contingency frequency control refers to the correction of the generation/demand balance following a major contingency event such as the loss of a generating unit/major industrial load, or a large transmission element. Contingency services are controlled locally and are triggered by the frequency deviation that follows a contingency event.

Under the NEM frequency standards AEMO must ensure that, following a credible contingency event, the frequency deviation remains within the contingency band and is returned to the normal operating band within five minutes.

Contingency services are provided by technologies that can locally detect the frequency deviation and respond in a manner that corrects the frequency, such as a generator or large interruptible industrial load which may be spinning (currently operating) or non-spinning. Some examples include:

- Generator Governor Response: where the generator governor reacts to the frequency deviation by opening or closing the turbine steam valve and altering the MW output of the set accordingly.
- Load shedding: where a load can be quickly disconnected from the electrical system (can act to correct a low frequency only).
- Rapid Generation: where a frequency relay will detect a low frequency and correspondingly start a fast generator (can act to correct a low frequency only).
- Rapid Unit Unloading: where a frequency relay will detect a high frequency and correspondingly reduce a generator output (can act to correct a high frequency only).

In aggregate, market participants offering contingency services are required to perform the following tasks:

- 6 second: arrest a rapid change in system frequency within the first six seconds of a frequency disturbance, and then provide an orderly transition to the 60 second service.
- 60 second: stabilise the system frequency within the first sixty seconds of a frequency disturbance, and then provide an orderly transition to the 5 minute service.
- 5 minute: restore system frequency to its nominal 50 Hz within the first five minutes of a frequency disturbance, and sustain response until notified by central dispatch.

The six types of contingency services are:

- Fast Raise (6 Second Raise): 6 second response to arrest a major drop in frequency following a contingency event.
- Fast Lower (6 Second Lower): 6 second response to arrest a major rise in frequency following a contingency event.
- Slow Raise (60 Second Raise): 60 second response to stabilise frequency following a major drop in frequency.
- Slow Lower (60 Second Lower): 60 second response to stabilise frequency following a major rise in frequency.
- Delayed Raise (5 Minute Raise): 5 minute response to recover frequency to the normal operating band following a major drop in frequency.
- Delayed Lower (5 Minute Lower): 5 minute response to recover frequency to the normal operating band following a major rise in frequency.

Participants must register with AEMO to participate in each distinct FCAS market. Once registered, a service provider can participate in an FCAS market by submitting an appropriate FCAS offer or bid for that service via AEMO’s Market Management Systems.

An FCAS offer or bid submitted for a raise service represents the amount of MWs that a participant can add to the system, in the given time frame, in order to raise the frequency. An FCAS offer or bid submitted for a lower service represents the amount of MWs that a participant can take from the system, in the given time frame, in order to lower the frequency.

During every dispatch interval of the market, NEMDE must enable a sufficient amount of each of the eight FCAS products from the FCAS bids submitted, to meet the FCAS MW requirement.

The contingency reserve requirement is determined dynamically in each five minute dispatch interval. It is based upon the largest generating unit output (or load block) in each interval, minus the load relief (the inherent change in demand due to frequency deviation, defined as a function of the load and a load relief factor).

C.2.2. Network Control Ancillary Services

NCAS are used for Voltage Control or Network Loading Control.

- Voltage Control: control the voltage at different points of the electrical network to within the prescribed standards.
- Network Loading Control: control the power flow on network elements to within the physical limitations of those elements.

C.2.3. System Restart Ancillary Services

SRAS are reserved for contingency situations in which there has been a whole or partial system blackout and the electrical system must be restarted. This can be provided by two separate technologies:

- General Restart Source: a generator that can start and supply energy to the transmission grid without any external source of supply.
- Trip to House Load: a generator that can, on sensing a system failure, fold back onto its own internal load and continue to generate until AEMO is able to use it to restart the system.

Both NCAS and SRAS are provided to the market under long-term ancillary service contracts negotiated between AEMO (on behalf of the market) and the participant providing the service. These services are paid for through a mixture of:

- Enabling Payments: made only when the service is specifically enabled
- Availability Payments: made for every trading interval that the service is available.

C.2.4. Non-market ancillary services

Network Support and Control Ancillary Services (NSCAS) are a non-market ancillary services that may be procured by AEMO or Transmission Network Service Providers (TNSPs) to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network. NSCAS may be acquired to control the active power or reactive power flow into or out of a transmission network in order to:

- maintain power system security and reliability of supply in accordance with the power system security and reliability standards
- maintain or increase its power transfer capability to maximise the present value of net economic benefit to all those who produce, consume or transport electricity in the market.

There are three types of NSCAS service:

- increase the secure loading of the network
- control the network voltages within acceptable limits including voltage stability
- improve transient and oscillatory stability limits of the network.

APPENDIX D. POTENTIAL PRICE ARBITRAGE INCOME FROM STORAGE

A simplified investigation of the price arbitrage opportunity for electricity storage has been undertaken using 2016 NEM price data.

D.1. Perfect foresight daily arbitrage

In the perfect foresight case, the average daily spread was calculated by finding the difference between the highest and lowest price for each day in 2016 (SA & NSW). As the trading intervals are recorded in 30-minute sections, the first two lowest intervals are subtracted from the highest two intervals to determine the spread representing one-hour worth of energy storage arbitrage in a single 24-hour period. An efficiency of 100% is assumed in calculations. The process of taking the difference between the highest and lowest prices was continued through to 24-hours' worth of storage. A guaranteed buying price of $60/MWh was tested, which shows that for a low enough price of energy, there might be a greater arbitrage potential with enough energy storage.

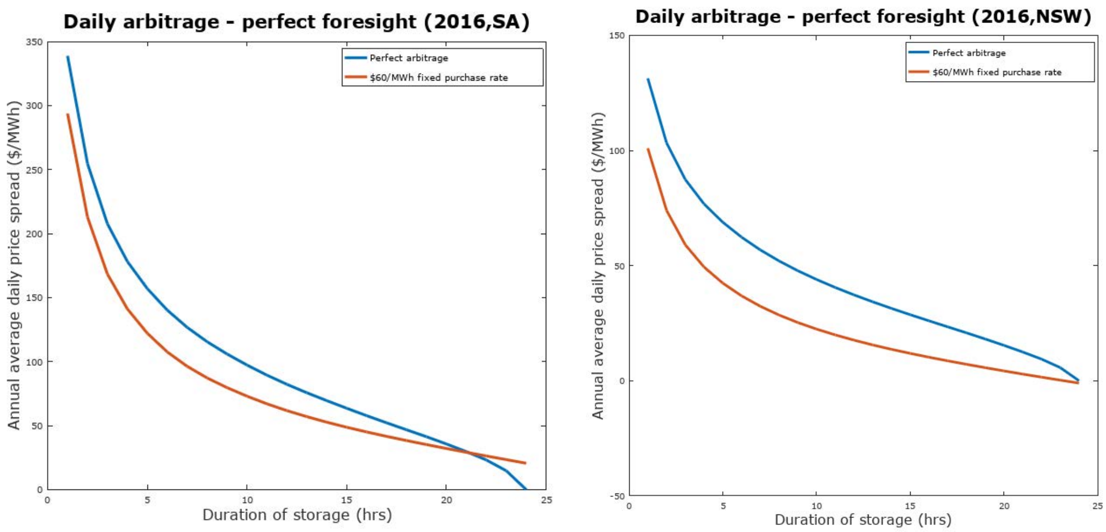


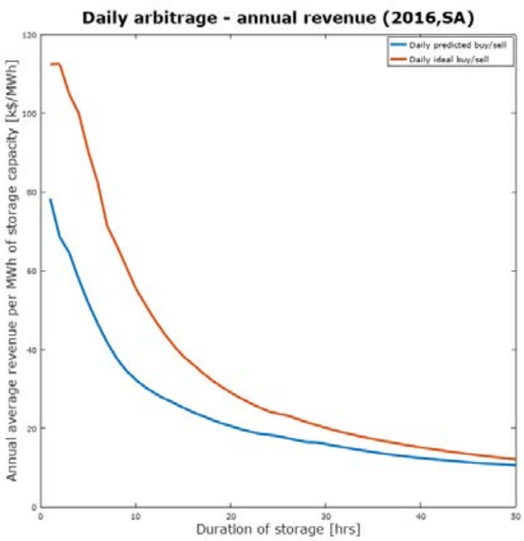
Figure 46: Average price spread for perfect foresight price arbitrage as a function of duration of storage

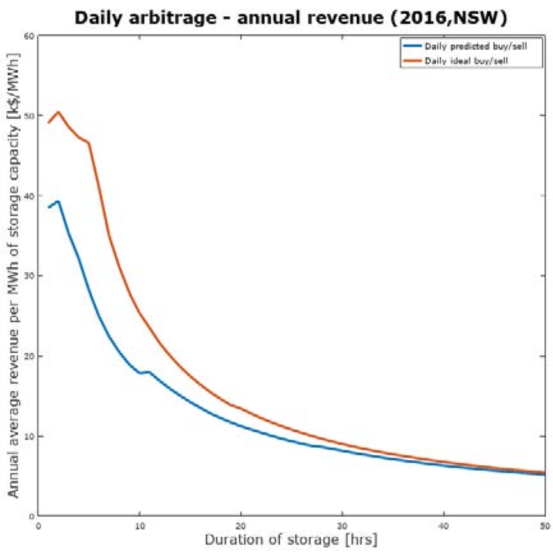
D.2. Strategies based on price history only

In the following cases, real data from AEMO for both SA and NSW electricity prices was used to determine potential arbitrage. Given that ideal buying and selling prices are not known, a simple model was presented utilising the upper and lower quartiles from the historical data. The three different cases are:

- Daily arbitrage: The predicted buy and sell prices use the upper quartile from the previous day as the selling threshold and the lower quartile as the buying threshold. The maximum amount of storage was varied from one to 50 hours. This was compared to the ideal thresholds by using the quartiles from the same day. The plot shows revenue calculated for the whole 2016 calendar year.
- Weekly arbitrage: The predicted buy and sell prices use the upper quartile from the previous week as the selling threshold and the lower quartile as the buying threshold. Maximum storage is varied from one to 50 hours and compared to the ideal thresholds from the same week. The plot shows revenue calculated for the whole 2016 calendar year.
- Yearly arbitrage: The predicted buy and sell prices use the upper quartile from the previous year (2015) as the selling threshold and the lower quartile as the buying threshold. Maximum storage is varied from one to 50 hours and compared to the ideal thresholds from the same year.

The fourth plot for each state shows the predicted revenues on the same graph. This indicates that basing a model for energy storage arbitrage on the previous day yields the highest potential revenue. Sioshansi *et al.* (2009) used a method to show that using a two-week back-casted dispatch rule gave an accuracy above 83% when compared to perfect foresight. This accounted for daily trends and weekday versus weekend trends, and avoided large seasonal variations.





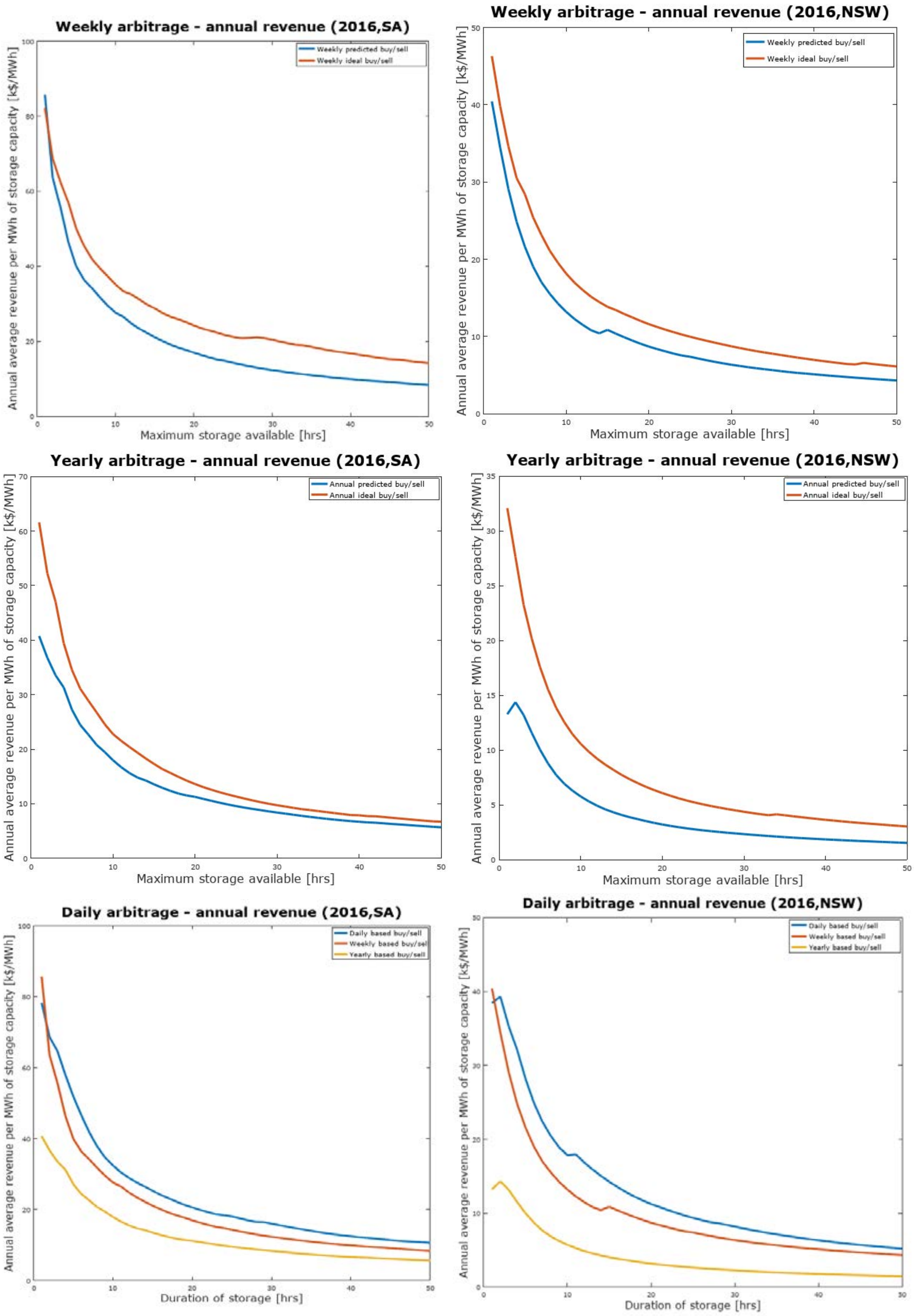


Figure 47: Annual total revenue for varying thresholds

In the plots below, the buying and selling thresholds have been varied (daily calculated) to illustrate the effect on the total annual revenue. As expected, by moving the buying and selling thresholds closer to the median, charging and discharging are more likely to occur. This could impact certain types of technologies, such as batteries, where an increased rate of charging and discharging will impact the efficiency and lifetime.

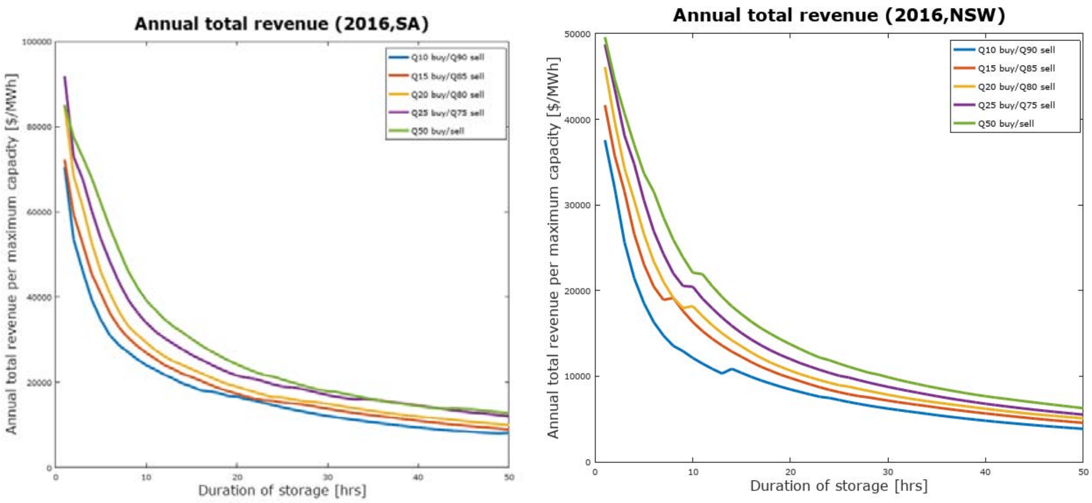


Figure 48: Annual revenue per amount of storage capacity

The following graph shows the annual revenue per MWh of sold energy over the year with the Q25 buying and Q75 selling thresholds. The slightly non-linear start indicates minor price variability but the consistent revenue per MWh sold is to be expected for a buying and selling algorithm based on price thresholds alone. This differs from the first arbitrage case where high and low price differences are found to determine price spread, as there will be diminishing returns as the price difference decreases. In this instance, the thresholds for buying and selling are set, which results in a stable amount of revenue across a year for the amount of energy that is being sold. In the case of NSW and SA in 2016, this revenue averages at $113/MWh in NSW and $240/MWh in SA.

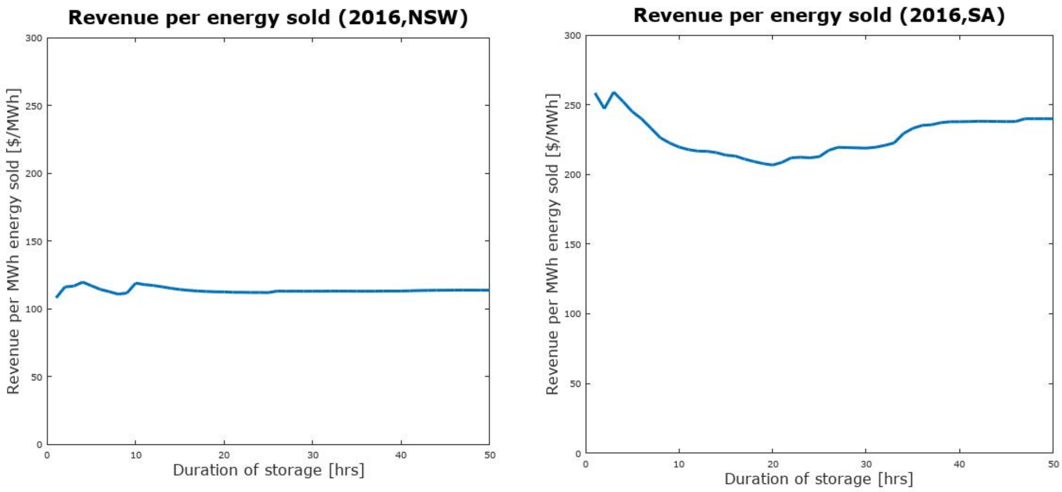


Figure 49: Annual revenue per amount of sold energy

APPENDIX E. INTERNATIONAL APPROACHES TO DISPATCHABILITY

Every global jurisdiction that has successfully encouraged the growth of renewable electricity generation is beginning to consider how to deal with the distinction between VRE and dispatchable RE.

Countries with developing economies that are facing rapidly-growing demand in excess of existing supply have tended to consider the need for levels of firm capacity from the outset. This leads to specific procurements for specified technologies and configurations. This seems to carry advantages of efficiency in administration, however it relies on policy makers 'picking winners' with the attendant risks of making the wrong choice.

Others have introduced specific targets for energy (electricity) storage. This brings the challenge of how to specify the storage needed. It also means that dispatchable systems that do not contain a qualifying storage component can be a missed opportunity. As this study has shown, fixing a duration of storage or power capacity size level or running a competition based on cost per MW vs cost per MWh can lead to potentially sub-optimal outcomes.

Introducing a time of day pricing multiplier into tariff support mechanisms for renewables has been applied at a certain level in one procurement in South Africa and in some procurements in California. This could have merit, particularly if it can be applied flexibly to adjust with changes in the supply and demand balance.

There have been discussions of operating targets for renewable ancillary services in parallel with targets for renewable generation. However, it does not appear that this has yet been implemented anywhere.

Although many countries have general capacity markets in addition to energy markets, as does Western Australia, the east coast National Energy Market appears to be unique in its consideration of a policy like the National Energy Guarantee. The NEG follows an early suggestion in South Australia of an Energy Security Guarantee that was to be a certificate-based scheme for dispatchable generation. While it remains to be seen how the NEG will be developed, this study has shown that dispatchable renewable generation is easier and less costly than many might have assumed. Thus, it is to be hoped that whatever form policy and market initiatives take, these will be mindful of the desirability of building a trajectory to a long-term optimal outcome on all three goals: emissions reduction, affordability and reliability. The risk is to fall back on the minimum action needed for system security in the short-term.

Around the world, policies to support deployment of energy storage to improve reliability and security include energy market reforms, procurement targets and mandates on utilities to procure storage and voluntary purchases. Financial incentives such as grants, loans and tax credits also exist. The following reviews various policy and market-based initiatives that have been implemented.

E.1. Strategic generation reserves

A number of countries, mainly with energy-only markets, have incrementally augmented their markets with reliability mechanisms (Spees, Newell and Brown, 2017). These do not exclusively focus on, but also do not preclude, renewable dispatchable capacity. Energy-only markets, like the NEM, do not place obligations on market participants to invest in capacity but rely on energy and ancillary services prices to drive investment. At the end of this section, case studies of countries which use long-term contracts for power production are also briefly discussed.

Belgium Strategic Reserves

In Belgium, the system operator procures strategic reserves on a one year forward basis, under contracts for up to three years. These are only deployed when there is a supply shortfall and the capacity does not participate in the normal market. This is a similar concept to AEMO's RERT program discussed in Section 4.7. This preserves the price signal for investment in the energy market.

In order to be effective, the reserve capacity (in the form of generation or demand response) must be additional to the capacity already available in the market. Some concerns are that generators may be incentivised to retire early in order to secure contracts under the strategic reserve. The strategic reserve is activated, either in the day-ahead market or real time when energy prices are at the market price cap. The providers of reserve have up to 6.5 hours to respond after being activated.

Existing peaking generators that otherwise would retire or be mothballed are a natural resource for strategic reserve because of the low fixed cost and high marginal cost structure. Demand response also lends itself well to strategic reserve with low fixed costs. In contrast, resources with high fixed costs and low marginal costs are better suited to operate many hours of the year in the energy market.

The cost of procuring strategic reserve is €35-38/kW/year (2015/16) and €29-36/kW/year (2016/17).

Texas Emergency Response Service and Reliability Must Run

In Texas, a demand response program called the Emergency Response Service (ERS) operates in the event of a forecast short-term supply shortfall. Participants commit to being available for curtailment and respond if they are directed to curtail by the system operator (ERCOT), in exchange for an availability payment.

ERS participants can offer resources with 10-minute or 30-minute notification and are required to respond to a signal from ERCOT within that time period. Resources are capped to a maximum of eight cumulative hours in an ERS contract.

ERS resources are procured under four-month contract terms through an auction three times per year. ERCOT procures resources across six availability periods to give load resources the flexibility to choose when to offer depending on the nature of their loads. ERCOT develops a capacity demand curve for each availability period reflecting both the expenditure limit and an offer cap of $80/MWh.

ERS resources have baselines representing their expected consumption during all hours of the availability period, based on factors including weather, day of the week, time of day, and consumption during similar days. ERCOT imposes an availability penalty on resources consuming less than their baseline throughout the availability period, except when called upon to curtail. The availability penalty discourages demand response from curtailing before being activated, even if energy prices are high. This is similar to strategic reserves, where reserves are prevented from reacting to energy prices and are activated only during times of system stress.

ERCOT also has a generation-based mechanism to support reliability. A unit at risk of imminent retirement may be kept online by ERCOT through a reliability must run (RMR) contract if the unit is needed to support transmission system reliability. Similar to ERS resources, the output of RMR-contracted units is mostly withheld from the energy market by requiring these units to offer at the cap of $9000/MWh into the day ahead market (the day ahead market is not mandatory for other resources). However, if the RMR unit is needed to relieve a binding transmission constraint, ERCOT may mitigate its offer down to a level below the offer cap.

Alberta Under-Frequency Load Shedding

Alberta is a significant electricity importer via interconnection with British Columbia. When this interconnection is offline it de-synchronises Alberta from the rest of the Canadian grid and the province becomes islanded. To enable fast response to such a contingency, the Alberta Energy System Operator (AESO) implemented a security service product called the Load Shed Service for Imports (LSSi) program in 2011. The LSSi program enables the AESO to stabilise frequency following a loss of generation contingency by disconnecting LSSi providers' load.

To be eligible to participate in the LSSi program, a load must be greater than 1 MW, have under-frequency relays installed at each site to detect when frequency drops below 59.5 Hz, and have real-time SCADA connectivity to the system operator. The committed load must be disconnected within 0.2 seconds when the frequency drops to 59.5 Hz. Twenty-one LSSi providers have signed three-year contracts with the AESO to participate in the program and are incentivised through a three-part payment structure:

- availability payments of $5/MWh are awarded across hours when the LSSi provider offers to disconnect their load
- arming payments are awarded when the AESO instructs the LSSi provider to continuously measure system frequency to enable rapid load shedding if the target frequency of 59.5 Hz is reached or a SCADA trip signal is received (payment is based on a fixed price set between the AESO and each LSSi provider that is established in the competitively sealed bid Request for Proposals for Load Shed Services for Imports (the RFP) process)
- tripping payments of $1000/MWh are paid when the LSSi provider's load is tripped offline.

The AESO calculates the LSSi requirements based on expected load and the combined net schedule import for the British Columbia and Montana interconnectors.

China Energy Storage Pilot

The Chinese power system in general is a command-and-control system with a hierarchy of dispatch centers and long-term contracts for both power production and use of interconnectors.

China has introduced a pilot program for energy storage to receive payment for peak shaving and frequency regulation in three of the country's northern regions where must-run coal plants and high levels of solar and wind have created a need for services (Chen, 2016).

The program allows in-front and behind-the-meter energy storage to participate. For installations co-located with generators, storage is required to deliver 10 MW for four hours at a time. These installations utilise existing compensation mechanisms for generators (e.g. if sited with a wind farm, can sell electricity at the onshore wind feed-in tariff rate).

Ontario Long-term Contracts

Administrative resource planning with the Independent Electricity System Operator (IESO) involves contracting for supply and determining when and what type of resource should be developed.

Many of these agreements are structured as contracts for differences, where contracted resources settle with the IESO for the difference between the energy price and the contract price.

In addition to the rising costs and contracts undermining market-based investment, there is concern that long-term contracts reduce competition and provide little incentive for emerging technologies. There are currently efforts underway to implement an incremental capacity auction in Ontario as a lower-cost mechanism for achieving long-term supply adequacy.

E.2. Storage targets and mandates

To date, only a few governments in the world have adopted targets for energy storage. A sub-set of these governments have also implemented mechanisms to support achievement of these targets in the form of mandates for utility-scale energy storage capacity.

California

California is a forerunner in the US and globally in policy on energy storage deployment to meet power grid needs. Policy frameworks developed by the California Public Utilities Commission (CPUC) became enforceable from 2014 and these are currently being contemplated by several other US states including Massachusetts, Nevada, New York and Oregon.[19]

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[19] Oregon passed legislation in 2015 requiring that the state's main utilities deploy 5 MWh of storage by 2020. In 2016, Massachusetts became the third US state to set a target of 200 MWh of energy storage by 2020 and Nevada is currently contemplating a mandate similar to California for implementation in 2018. In New York City, legislation has passed to establish funding programs to support energy storage deployment. In Canada, the province of Ontario has mandated the procurement of energy storage, with most projects designed to provide frequency regulation services or voltage support to improve grid functions. A two-part solicitation in late 2015 resulted in contracts for 50 MW of storage capacity.

In general, Californian policy is based on end user applications of storage (transmission, distribution or behind-the-meter) and a mandate on utilities to procure storage. CPUC set an energy storage target of 1325 MW by 2020[20] to be achieved by electric utilities Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric (Public Utilities Commission, 2015). Under the initiative, biennial procurement targets for 2014 to 2020 (in MW) are allocated to each utility for storage at transmission, distribution and customer levels with some flexibility in shifting MWs between the three sectors allowed. The overarching goals of the initiative are for energy storage to optimise the grid (including through peak reduction, contribution to reliability, or deferment of transmission and distribution upgrades), renewable energy integration and emissions reduction to 80% below 1990 levels by 2050.

Utilities are required to submit procurement plans to the CPUC, which include cost recovery methodologies for procurement and utility-owned storage capped at 50% of targets. Cost/benefit analysis is used by utilities to illustrate how storage may provide services in transmission, distribution and customer applications, with utilities using their own proprietary evaluation approaches for assessing bids but a consistent approach for reporting/benchmarking purposes.

Technologies eligible as energy storage are “commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereby dispatching energy”. The process of storing energy can use mechanical, chemical or thermal means, and/or store thermal energy for direct use heating/cooling at a later time to displace electricity. All energy sources are eligible to bid except pumped storage over 50 MW. In considering the 2014 utility submissions, there were deliberations about whether a broad or narrow interpretation of energy storage should apply. Ultimately, the Commission allowed vehicle to grid technologies, the eligible storage component of biogas, solar thermal and hybrid thermal generation, but disallowed biogas without a storage component and vehicle-grid integration, which provides for a controlled rate of charging in response to signals from the grid and uses stored energy for non-grid purposes.

To date, determinations by the CPUC have clarified particular technologies as eligible energy storage rather than purely basing eligibility on performance characteristics such as capacity or duration of holding charge. At the same time, the CPUC provides storage use-case as examples, allowing for storage to be co-located with generation as well as stand alone.

An Energy Storage Roadmap developed by the ISO, CPUC and the California Energy Commission following the Commission’s initial decisions in 2014 (California ISO, 2014), identified several implementation issues including the need to:

- realise revenue opportunities consistent with the value energy storage can provide (i.e. energy storage can have multiple use applications, an example is serving as a distribution reliability asset during some times but also serving the wholesale market at other times)
- develop a common methodology for evaluation by utilities to support CPUC decisions on procurement and make these models publicly available.

[20] This mandate was expanded by an additional 500 MW of energy storage in 2016. In addition, utilities in southern California were directed by the state’s Public Utilities Commission to quickly procure over 60 MW of electricity storage by year’s end to overcome an expected electricity shortfall due to a devastating natural gas leak discovered in late 2015.

Puerto Rico Minimum Technical Requirement Regulations

Puerto Rican government-owned Autoridad de Energia Electrica introduced a mandate in 2013 that renewable energy project developers must incorporate energy storage into new projects (Colthorpe, 2013). New projects must have enough storage to meet 30% of its rated capacity for approximately 10 minutes to assist with frequency control and enough energy storage to provide 45% of the plant's maximum generation capacity for at least one minute for ramping control to compensate for changes in variable power from wind or solar resources.

The company, which is a vertically integrated generator and network provider, undertook evaluation to set levels of compliance that developers could meet. It is implementing projects through PPAs with project developers.

South Africa

Initially a renewable energy feed-in tariff with differential rates for energy sources was proposed in South Africa but not used. Instead competitive auctions were held with tariff rates used as price caps. The Renewable Energy Independent Power Producer Procurement Program (REIPPPP) sought the addition of new electricity capacity, which to date has resulted in the awarding of contracts to a range of renewable sources including wind, solar PV, CST, landfill gas, biomass and small hydro. The primary policy drivers for the REIPPPP were for diversified supply from renewable energy sources. Due to the program supporting commercial wind and solar technologies, a dedicated round for solar CST was held using a differentiated tariff with a base and peaking rate component. The peaking rate was applied from 4.30pm to 9.30pm at 270% times the base rate in recognition of the higher value in electricity supplied (Department of Energy, 2015).

E.3. Voluntary purchase / investment

Early adoption of storage has primarily occurred through tenders, attracting responses from many suppliers prepared to be loss leaders in order to demonstrate use of the technology. This has included tenders for renewable energy projects that mandated the inclusion of a storage component or dispatchable capacity. These procurements have been pursued by national and state governments, and also by utilities. In some cases, but not all, the deployment of storage has been in response to natural disasters that have highlighted a role for microgrid distributed energy generation to operate separately to main grids during emergencies. India called for its first tender for solar energy (300 MW of projects) that mandated the inclusion of a storage component. In the US there were several solar and storage PPAs entered into between utilities and project developers in early 2017, achieving very competitive prices due to the presence of tax and other incentives. In Australia, the Federal Government has indicated it may invest in pumped hydro expansions and the ACT, South Australian, Victorian and Queensland governments have or are in the process of procuring battery storage installations.

UK Enhanced Frequency Response tender

National Grid (the owner and operator of the transmission grid in England and Wales) procured 200 MW under the Enhanced Frequency Response in 2016 (National Grid Electricity Transmission, 2016). The tender resulted in eight four-year contracts being signed to deliver fast frequency response by 2017-18, which will deliver a saving of £200 million over four years according to National Grid when compared with existing frequency response services.[21]

The EFR included the option of two service types, wide deadband and narrow deadband. These differ in the size of the frequency insensitive zone designed to enable storage technologies to manage state of charge. For the first tender round an initial requirement of 200 MW of EFR with a maximum 50 MW per provider was set.

In addition to the ability to meet service and commissioning criteria, bids were assessed on price and hours of availability. This meant that for each half hour of the tender, the total cost of the tender was calculated along with the alternative response costs that the tender would offset. The benefits of each tender were expressed as a percentage of the tender cost and units ranked by percentage benefit and selected up to the requirement. The alternative costs were derived from the cost of procuring standard frequency response, and an ‘exchange rate’ was calculated that describes how much conventional frequency response (Primary, Secondary and High response) can be offset by each MW of EFR. Each tender was expressed as a volume of standard response and evaluated as a normal FFR tender. The exchange rates are different for the service types and are forecast for every half hour of the contract. The benefit of a tender is therefore dependent on the service type, the hours for which the service will be provided, and the price of the tender.

While proponents of battery systems, demand reduction and thermal generation bid into the tender, the winning bids were from battery solutions. There were eight successful tenders providing 201 MW of EFR at a total cost of £65.95 million with an average price of £9.44/MW of EFR/h.

US Solar and Storage PPAs

In January 2017, Kauai Island Utility Cooperative signed a PPA with AES for a 28 MW solar and 100 MWh battery facility at a reported US11c/kWh. In March 2017, KIUC also partnered with Tesla to install a 13 MW solar and 52 MWh battery plant at a reported price of US13.9c/kWh.

In April 2017, Salt River Project signed a 20-year PPA with NextEra Energy for electricity from a 20 MW solar and 10 MW lithium-ion storage facility at an undisclosed price.

In May 2017, Tuscon Electric signed a PPA with NextEra Energy to purchase power for 20 years at a reported US4.5c/kWh from a 100 MW solar and 30 MW/120 MWh energy storage facility (Maloney, 2017).

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[21] Enhanced frequency response is a relatively new service developed to improve management of the system frequency pre-fault, i.e. to maintain the system frequency closer to 50 Hz under normal operation. Enhanced frequency response is defined as being a service that achieves 100% active power output at 1 second (or less) of registering a frequency deviation. Existing frequency response services of Primary and High have timescales of 10 seconds, and Secondary has timescales of 30 seconds.

In Maryland, energy storage technologies are eligible for a 30% tax credit. California's Self-Generation Incentive Program supports behind-the-meter residential and larger energy storage installations, while incentive programs also exist in Nevada and New Jersey (Smart Electric Power Alliance, 2017).

E.4. Incentive approaches

Internationally, incentives have been a complementary approach to encouraging storage. The appropriateness of using mandates or incentives will depend on the policy objectives. Where the quantity of storage sought is important, mandates may be more effective. Incentives may be more appropriate if policy objectives are to encourage development and deployment of new energy storage technologies by end users.

In general, the approach has been to pursue standalone targets and mandates or ad hoc procurement as a natural response to high levels of variable renewable energy or weak grids. The incorporation of storage into Renewable Portfolio Standards or similar mechanisms that require energy suppliers to source electricity supply from renewable energy sources, which is a hybrid mandate/incentive approach, has generally not been pursued in the US. In Nevada, a proposal to amend Renewable Portfolio Standards with energy storage to allow each kilowatt-hour of energy delivered by energy storage to have twice the value other eligible generation was vetoed in June 2017.

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