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Renewable Energy Storage Roadmap

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Acknowledgements

CSIRO acknowledges the Traditional Owners of the lands that we live and work on across Australia and pays its respect to Elders past and present. CSIRO recognises that Aboriginal and Torres Strait Islander peoples have made and will continue to make extraordinary contributions to all aspects of Australian life including culture, economy and science.

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We are grateful for the time and input of the stakeholders from industry, government and academia who were consulted throughout this project. A full list of stakeholders consulted may be found in Appendix A.

Supporting organisations

GOVERNMENT OF WESTERN AUSTRALIA

Australian Government

NSW GOVERNMENT

Australian Government
Australian Renewable Energy Agency

ARENA

BHP

GHD

Woodside

apa

ASTRI
Australian Solar Thermal Research Institute

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Contents

Foreword

Australia leads the world in solar, and we have reduced our emissions by 22 per cent from their peak in 2005, but to go further we need to solve the energy storage problem. As a country, the challenge before us is clear: Australia needs to achieve our net zero emission targets while maintaining a reliable and affordable energy supply. As Australia's national science agency, CSIRO has turned its decades of expertise in energy to answer this challenge through this Renewable Energy Storage Roadmap.

We delivered our first net zero scenario for Australia in our 2019 Australian National Outlook report. Today, our modelling clearly shows that all decarbonisation pathways have relied on gas to ensure energy stability but, to get to net zero, gas needs carbon capture and storage – in fact all pathways to net zero share one thing in common: a massive increase in storage capacity. Energy storage facilitates the integration of renewables, enhances grid stability and reliability, and supports the energy transition of industries. There is no silver bullet for energy storage because it's hard to beat the unique energy characteristics of fuels, so we need multiple shots on goal from batteries, hydrogen, pumped hydro, and a host of new science-driven technologies. To ensure sustained progress towards net zero, we need a robust pipeline of projects that use diverse technologies supported by industry, government, research and community stakeholders.

That is easier said than done. Next-generation storage technologies need to keep pace with rapidly rising demand, which is projected to double as building and transport industries electrify; address the challenge of diverse geographical and end use contexts (there won't be one technology to suit every need); and the complications associated with the uncertainty surrounding future energy market design, infrastructure availability, and technology costs.

Fortunately, an array of developing storage technologies is on the cusp of commercial viability. These technologies have the potential to improve access to electricity supply in remote communities, support cost-effective decarbonisation in manufacturing industries, and transform Australia into a green hydrogen export superpower.

CSIRO is uniquely positioned to support the coordinated investment and scale up of renewable energy storage in Australia. We have been at the forefront of energy storage research – including advancements in battery technology, ultracapacitors, hydrogen and liquid renewable fuels – for more than 20 years. Today, we are forming a collaborative network of partners across industry, government and research to develop a Renewable Energy Powerhouse mission that will accelerate this work. We are investing in breakthrough research through our Revolutionary Energy Storage Future Science Platform, paving the way for the next cutting-edge technologies. And we continue to work closely with our partners in industry to develop low-emissions solutions that meet their needs.

CSIRO recognises that a challenge of this scale will take collaboration and a long-term view, which is why this Roadmap was developed in consultation with government and industry, highlighting mature technologies that can be deployed today, as well as early solutions requiring further exploration. Australia, like the world, is built largely on fossil fuels and it's critical that we help them transition to the new net zero world. Everyone will have a role to play in building our low-emissions future, and we must all go on this journey together, so no one is left behind.

Larry Marshall
CSIRO Chief Executive

Glossary

A-CAES	Adiabatic compressed air energy storage
AEMO	Australian Energy Market Operator
EV	Electric vehicle
CAES	Compressed air energy storage
CAPEX	Capital expenditure
CCUS	Carbon capture, utilisation and storage
CO_2	Carbon dioxide
CRI	Commercial readiness index
CST	Concentrated solar thermal
D-CAES	Diabatic compressed air energy storage
DER	Distributed energy resources
eTES	Thermal energy storage (electricity input)
eTESe	Thermal energy storage (electricity input, electricity output)
eTESh	Thermal energy storage (electricity input, heat output)
FCAS	Frequency-control ancillary services
FCEV	Fuel cell electric vehicle
H_2	Hydrogen
HRS	Hydrogen refuelling station
ICT	Information and communication technologies
ISP	Integrated System Plan
LAES	Liquid air energy storage
LCOS	Levelised cost of storage
Li-ion	Lithium ion
MGA	Miscibility gap alloys
Na-ion	Sodium ion
NEM	National electricity market
OPEX	Operational expenditure
PHES	Pumped hydro energy storage
PV	Photovoltaic
R&D	Research and development
RD&D	Research, development and demonstration
T&D	Transmission and distribution
TES	Thermal energy storage
TRL	Technological readiness level
V2G	Vehicle to grid
VRE	Variable renewable energy
VPP	Virtual power plant
VRFB	Vanadium redox flow batteries
ZNBR	Zinc–bromine batteries

Storage durations

Short duration	Less than 4 hours of energy storage
Medium duration	4–12 hours of energy storage
Long (intraday)	Between >12 and 24 hours of energy storage
Long (multiday)	Between >24 and 100 hours of energy storage
Seasonal	More than 100 hours of energy storage

Energy

MJ	Megajoule (1,000,000 joules)
kW	Kilowatt (1,000 watts of electrical power)
MWe	Megawatt electric (1,000,000 watts of electrical energy)
MWth	Megawatt thermal (1,000,000 watts of thermal energy)
MWh	Megawatt hour (1,000,000 watts of power used in an hour)
GW	Gigawatt (1,000 megawatts of electrical power)
GWh	Gigawatt hour (a gigawatt of power used in an hour)
TWh	Terawatt hour (1,000,000 megawatt hours)
GJ	Gigajoule (1,000,000,000 joules)
PJ	Petajoules (1,000,000 gigajoules)

Volume

kL	Kilolitres (1,000 litres)
L	Litres

Executive summary

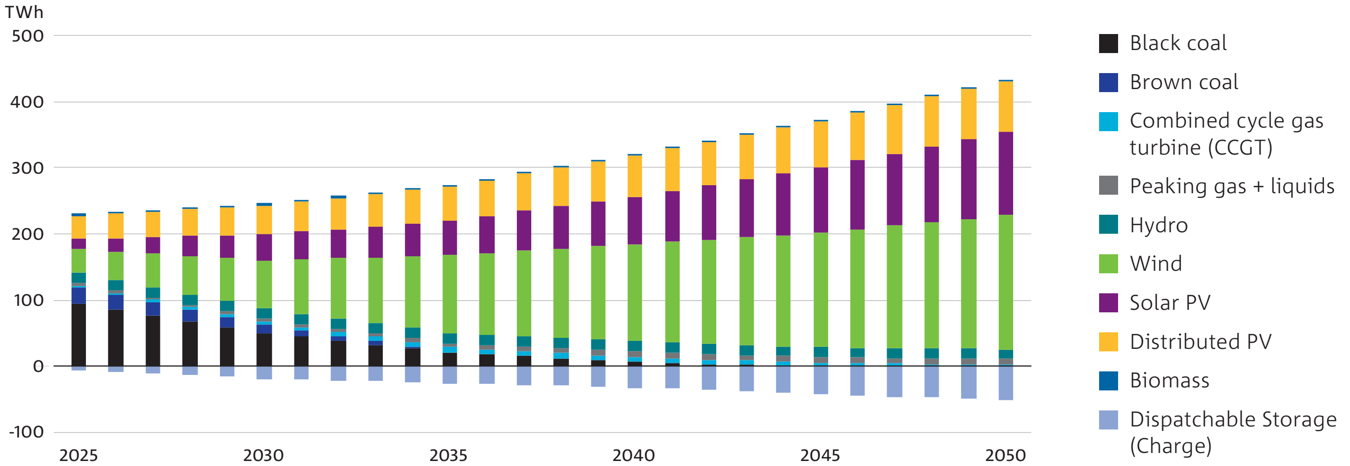
Storage of renewable energy is essential to ensure access to secure, reliable and affordable energy as Australia transitions to net zero.

Australia's target for net zero emissions by 2050 will result in significant changes across the energy system, creating the need to increase its capacity to store energy. This will be driven by an electricity generation mix dominated by wind and solar photovoltaic (solar PV; see figures below), increased electrification in end-use sectors, including transport, industry and buildings, and increases in 'green' hydrogen for domestic use and export.[1]

Although there are existing storage systems used to deliver energy from fossil fuels, higher levels of renewables in Australia's energy system will result in a greater requirement for renewable energy storage technologies. These include electricity storage through electrochemical processes (e.g. batteries), mechanical storage (e.g. pumped hydro energy storage [PHES]), chemical storage (e.g. hydrogen in tanks or pipelines) and thermal storage (e.g. molten salts).

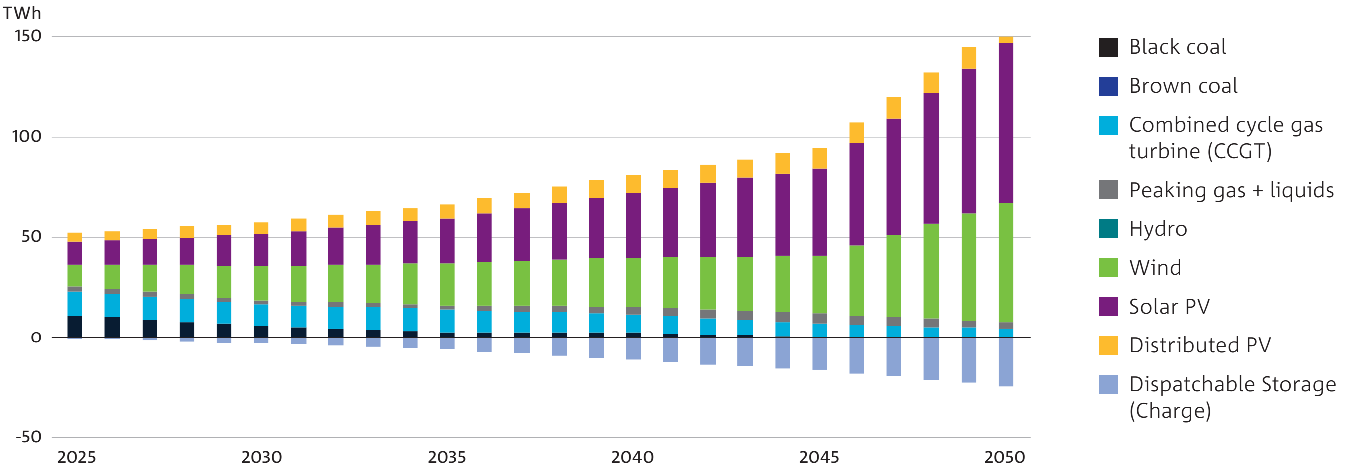
Developed in collaboration with industry and government stakeholders, this roadmap provides a starting point for decision makers across end-use sectors and Australia's electricity markets (the National Electricity Market and Western Australia) in developing a plan for scaling up renewable energy storage.

Forecast electricity and storage generation in the National Electricity Market (NEM) to 2050, *Step Change* scenario



Notes: Although customer (non-VPP) storage is not explicitly modelled in this framework, this could reflect up to 10.7 TWh of charge by 2050. Terminology: CCGT, combined cycle gas turbine; PV, photovoltaic; VPP, virtual power plant.

Forecast electricity and storage generation in Western Australia (WA) to 2050, *Step Change* scenario



Notes: Although customer (non-VPP) storage is not explicitly modelled in this framework, this could reflect up to 3.4 TWh of charge by 2050. CCGT, combined cycle gas turbine; PV, photovoltaic; VPP, virtual power plant; WA, Western Australia.

1 Green hydrogen refers to hydrogen produced from renewable energy sources.

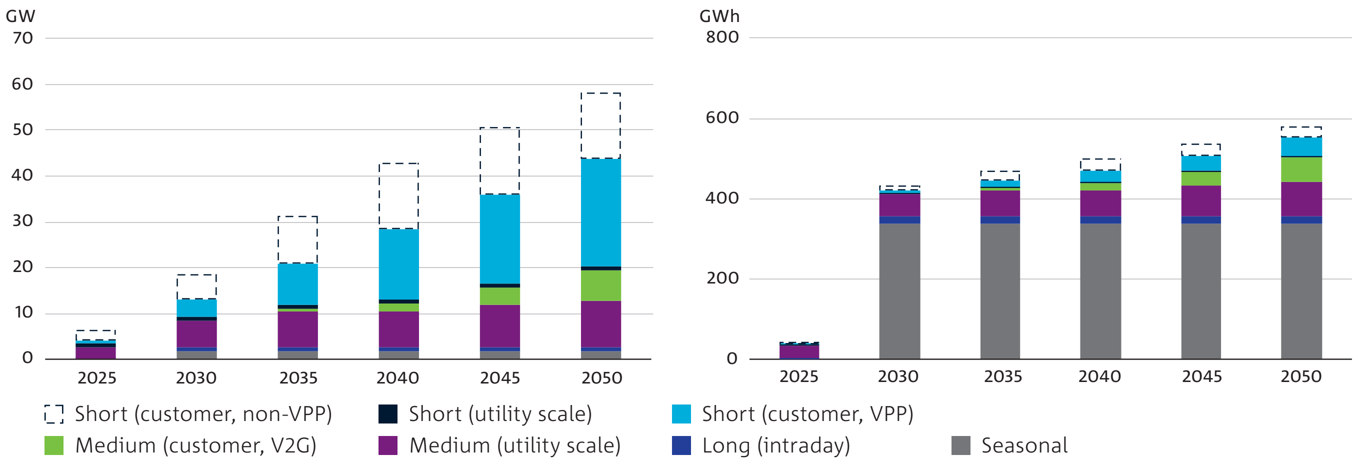
Given Australia's target for net zero emissions by 2050, the demand for renewable energy storage is projected to be significant.

This roadmap uses a scenario-based approach, building on pathways developed in the Australian Energy Market Operator's (AEMO) 2022 Integrated System Plan (ISP) that could materially impact Australia's energy sector. The *Step Change* and *Hydrogen Superpower* scenarios suggest that the national electricity market (NEM) could require 44–96 GW/550–950 GWh of dispatchable electricity storage capacity by 2050, whereas Western Australia (WA) could require 12–17 GW/74–96 GWh (see figures below).

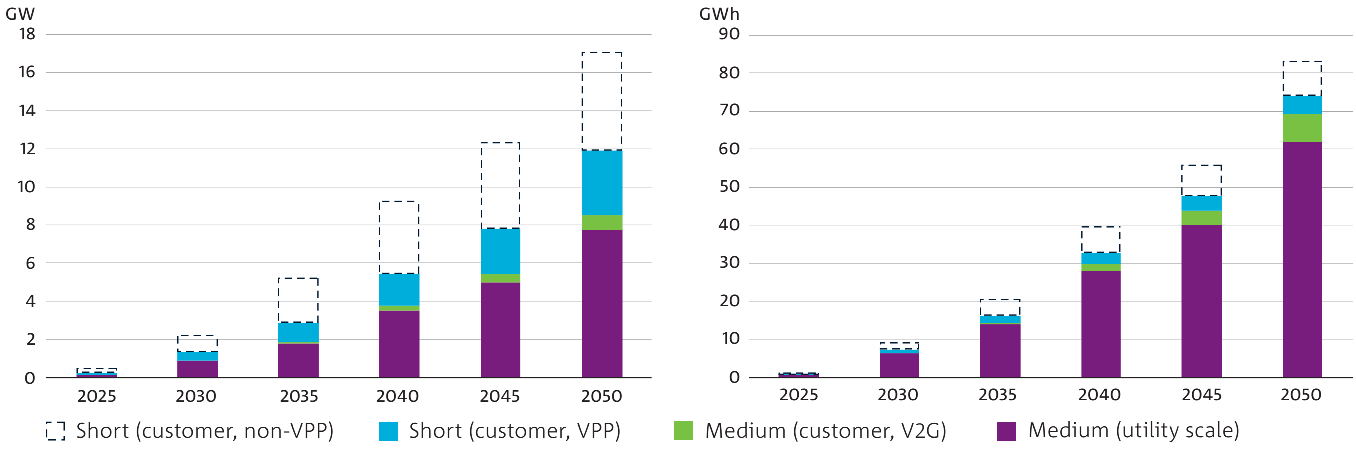
As Australia transitions to net zero, there may also be an increase in thermal storage requirements, driven by the greater need for renewable process heat in industrial production. In addition, the strong profile for hydrogen exports in the *Hydrogen Superpower* scenario will lead to large increases in the demand for both electricity and hydrogen storage systems.

Despite the uncertainty in storage outcomes in 2050, the modelling results suggest that all net zero pathways will require large investments in renewable energy storage capacity. In particular, larger investments in short- and medium-duration electricity storage are expected to be required to provide reliable electricity supply, and significant investments in hydrogen (or hydrogen carrier) storage systems would be required if Australia is to be a leader in green hydrogen exports. Investment is also likely to be required for thermal energy storage systems, given the important role of process heat in industry and the use of variable renewable energy for heat production and requirement for constant heat supply.

NEM electricity storage capacity, *Step Change* scenario



WA electricity storage, *Step Change* scenario



Notes: Estimates are based on a least-cost modelling approach to achieve net zero emissions at a national level, rather than a jurisdictional level (see Appendix B for more details). Dashed bars reflect customer (non-VPP) storage sourced from AEMO's 2022 ISP. Terminology: AEMO, Australian Energy Market Operator; ISP, Integrated System Plan; V2G, vehicle to grid; VPP, virtual power plant. Storage durations: Short, < 4 hrs; Medium, 4 - 12 hrs; Long intraday, >12 - 24 hours; Seasonal, > 100 hours.

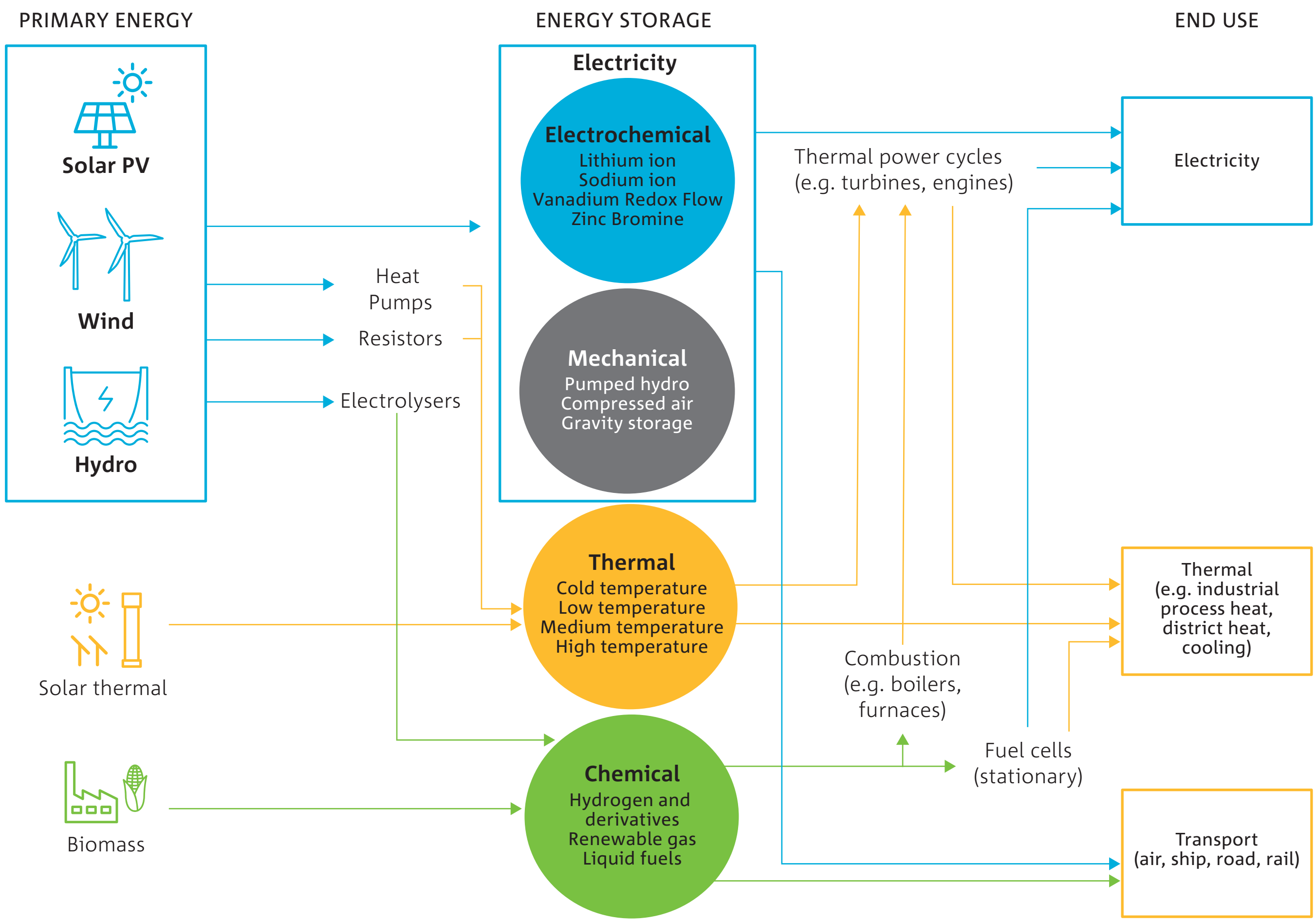
There is a range of storage technology options, both commercial and under development, with different strengths and weaknesses depending on end use.

Australia's energy storage requirements are diverse and the decision to invest in storage (or solutions to minimise storage needs) is complex. Determining the most competitive and appropriate forms of energy storage requires an understanding of the context in which the storage system will be used (see figure below).

This requires stakeholders to go through a site- and region-specific approach to understand the role of energy storage, the deployment considerations and the technology options available (both commercial and developing). This approach is critical because site and regional factors can affect the requirements, costs, risks and integration considerations for a given storage system (and their various configurations or subsystems). Site and regional factors can also affect the applicability or viability of technologies even among similar sectors and specific end-use applications.

This report applies this approach, combining detailed qualitative and quantitative analysis with stakeholder input to consider energy storage technology options across a selection of end-use applications. This broad-based analysis will assist stakeholders in industry, government and research to make informed choices.

Role of renewable energy storage in Australia's energy system



Notes: Graphic developed in consultation with ITP Thermal. Terminology: PV, photovoltaic.

Although energy storage will be key to supporting higher levels of decarbonisation and renewable energy deployment, many Australian sectors face challenges in integrating renewable storage technologies.

Energy storage is required for higher levels of renewable penetration in Australia's major grids and industries, and can support the decarbonisation of industries requiring process heat. Storage can also help remote Australian communities decarbonise and reduce their reliance on diesel for electricity supply.

However, several technology challenges will affect Australia's ability to meet its future demand for energy storage. These challenges are due, in part, to the limited set of commercially mature ('bankable') storage options and their inherent constraints based on end-use applications. These challenges are compounded by the fact that today's decisions relating to decarbonisation and storage depend on current expectations for future market design, availability of infrastructure and technology costs, which remain uncertain.

Major grids will require a significant scale of storage of varying durations to manage imbalances in electricity supply and demand as they transition. There are limited commercially mature (bankable) energy storage options in Australia that are deployable in the near term, and the most widely deployed systems in Australia, lithium-ion batteries and pumped hydro, face supply chain risks and geographical constraints respectively.

For **remote and off-grid mining** sites, short-duration energy storage within a hybrid generation grid can provide significant emissions reductions in the near term and reduce existing levels of fossil fuel usage. However, eliminating emissions in remote mining will also require long-duration storage technology options. While several options could potentially be commercially competitive with diesel, these are not widely demonstrated at scale across mining operations.

Energy storage paired with renewables has the potential to increase access to electricity supply for **remote communities**, support high levels of decarbonisation and reduce electricity costs. However, the ability to achieve these outcomes across diverse community types and regions will require community engagement. Storage systems will need to be cost-effective in terms of upfront investment and ongoing costs, and easy to maintain. Eliminating emissions will require storage systems capable of maintaining power quality and providing reliable energy for days or weeks.

Thermal and chemical storage systems, as well as process electrification, have the potential to enable the **manufacturing** industry to cost-effectively decarbonise and meet their mid-temperature (150–500°C) heat requirements. However, further demonstration and scale up is required to increase knowledge of decarbonisation pathways and associated storage technology options, as well as to reduce real (or perceived) commercial and technical risks.

The decarbonisation of Australian industries that require high temperature (500°C and above) process heat, such as **alumina calcination**, can have significant implications for storage, with the appropriate solution depending on the chosen decarbonisation pathway. However, industry decisions related to storage will be made in the context of a broader and highly integrated system. Such decisions often bear high up-front costs and are high-risk exercises which can be exacerbated by insufficient information due to a lack of technology maturity and scale.

Large-scale storage will play a critical role in realising **Australia's hydrogen export** industry and could support the development of a domestic hydrogen economy. However, the choice and type of storage required will depend on how a given export value chain is optimised, with implications for maritime and pipeline infrastructure.

Hydrogen storage could play a key role in decarbonising **heavy-duty vehicles**, as fuel cell electric vehicles (FCEVs) are expected to become increasingly competitive for high-load, long-range operations requiring short recharging times. A reliable hydrogen refuelling network will require hydrogen storage at various points along the distribution system. Storage choices will be based on the optimal distribution model to service a given area and should consider opportunities to leverage shared hydrogen assets, such as large-scale hydrogen production and storage at hubs.

Near-term energy market design decisions will shape the course of Australia's storage-related needs and investments, requiring further consideration and planning.

As new energy storage technologies increase in commercial readiness and new business models are introduced to the market, policy and regulatory frameworks will need to evolve to optimise the energy system. This will be underpinned by an efficient mix of energy storage deployments.

Market reforms and research and analysis into the design of Australia's future electricity market are currently being undertaken by various stakeholders. In addition, concurrent work being undertaken internationally by governments and industry groups can support knowledge sharing and inform best practice.

A selection of market-related categories from Australian and international publications and stakeholder consultations have been captured. This report provides a broad range of example considerations for each category to support the discussion. Although largely related to the electricity market, where relevant non-electricity considerations with implications to thermal and chemical storage were also raised by stakeholders.

CATEGORY	DESCRIPTION
Storage specifications	Specifications for storage across grants, tenders, standards and regulations are often framed in terms of technology type (e.g. batteries) or its role (e.g. generation asset or load-modifying resource). This limits the scope of technologies that could be considered to meet end-user needs across sectors. Greater collaboration may be required to identify and eliminate terminology that may create unintended biases and reduce competition.
Valuing and incentivising energy storage services	Storage incentives should be designed to achieve a low-cost, reliable and secure energy system, and should be aligned to the value of the services delivered by the storage asset. Market mechanisms that provide long-term market signals or revenue streams can offer investors and technology proponents greater certainty as to the commercial viability of their storage asset. Other more direct forms of support (e.g. targets and tenders) can help incentivise more immediate implementation of energy storage projects. These incentives should be considered across electricity, thermal and chemical storage.
V2G, VPPs and consumer incentives	Successful integration of customer-owned storage into the grid depends not only on technical developments and consumer engagement, but also on the right market settings to incentivise and compensate consumers and providers for vehicle-to-grid (V2G) and virtual power plant (VPP) investments, alongside information to help inform consumers of their choices and support decision making.
Coordinated long-term infrastructure planning and development	Focused and long-term coordinated planning involving government and industry is required to make informed decisions that will deliver a low-cost energy system in the long run. This includes aligning industry and transport decarbonisation pathways with associated storage and infrastructure investments, as well as incorporating sector coupling in energy system planning.

Australia will need to rapidly develop a pipeline of projects across a portfolio of energy storage technologies to address key technology challenges across different end-use applications and geographical locations.

To address the key challenges identified, government, industry and research institutions will need to co-invest to accelerate technology commercialisation and scale up across a diverse portfolio of energy storage technologies. Fortunately, a range of developing storage technology options have progressed past the research and development (R&D) phase and are now reaching commercial milestones. The table below summarises the gaps and uncertainties, and sets out technology recommendations to address them.

Although this report has examined energy storage needs to 2050, the technology recommendations require urgent action and attention prior to 2030 to account for scale up and the availability of commercially competitive, widely deployed and easy-to-finance technology options.

CATEGORY	CHALLENGES	RECOMMENDATIONS
Short-duration electricity storage (1–4 hours)	Short duration storage is expected to play a major role in decarbonisation across Australia's grids and its industries, particularly in the near term (to 2030). Although commercially mature options exist to meet Australia's short-duration storage needs, there are supply chain risks that could create deployment bottlenecks and drive up prices.	• Continue to deploy commercial utility scale (100+ MWh) short-duration electrical storage technologies alongside the demonstration of technologies currently in development to create optionality. • Consider and develop strategies to de-risk battery supply chains through a number of strategic diversification pathways, including, but not limited to: strategic supply chain and manufacturing partnerships; developing domestic value chains; developing resource circularity; and investing in research, development and demonstration (RD&D) for alternative battery chemistries.
Medium (4–12 hours) and long intraday (12–24 hours) electricity storage	Australia's medium to long intraday storage demand will become more significant in the near term with deeper levels of renewables penetration, and for industry sites with limited grid connectivity. Although some commercial technologies exist, they are not always applicable depending on the end use or region in question. There are also several other technology options currently in development, but these are not yet competitive and require further demonstration and deployment.	• Rapidly demonstrate and commercially deploy medium to long intraday duration technologies capable of providing hundreds of megawatt hours to multiple gigawatt hours of storage to create a diverse set of options for major grids and industry applications. • Conduct further regional studies to better understand geological storage opportunities, such as with adiabatic compressed air energy storage (A-CAES) and PHES subsystems, and opportunities to take advantage of existing capital and sites, including evaluating opportunities created through mine closure efforts.
Long multiday (24–48 hours) and seasonal (100+ hours) electricity storage	Multiday and seasonal storage will play a key energy 'insurance' and resilience role in major and isolated grids, with deployments expected to increase beyond 2030 as higher levels of renewables are adopted. However, at these durations, storage technology options are limited and often have long lead times, with many stakeholders still considering investment options, including those that minimise storage investments, and evaluating trade-offs as they transition to net zero.	• Conduct further analysis to better understand Australia's requirements for multiday and seasonal storage, the trade-offs that exist and the technology pathways available. • Develop the pipeline of projects to meet Australia's potential long-term seasonal and multi-day needs, including identifying and implementing opportunities to accelerate PHES deployments, and progressing emerging multi-day and seasonal technologies.

CATEGORY	CHALLENGES	RECOMMENDATIONS
Storage for mid-temperature processes (150–500°C)	Australia has many industries and industrial sites, small and large, that are currently reliant on what is classified as mid-temperature industrial process heat. These processes are not always easy to decarbonise with conventional electrical pathways alone, creating a potential opportunity for the use of thermal storage or the storage and use of hydrogen. There is a broad range of systems that are mature, or nearing technical maturity. However, a lack of information on technology options and the capital expenditure involved in retrofitting existing plants are barriers to implementation.	• Pilot and commercially deploy end-to-end thermal and hydrogen storage systems, alongside investigations into electrification options, in a range of industrial processes to better understand cost, business model and deployment considerations, and to reduce actual and perceived risks.
Storage for high-temperature processes (500°C and above)	High-temperature industrial processes are difficult to decarbonise. Although this report focuses on alumina, Australia has various industries with similar high-temperature requirements spanning cement, chemicals, mineral processing and steel. For these industries, several decarbonisation pathways exist – electrification, the use of thermal energy systems or the use of hydrogen to create the heat required. Regardless of the decarbonisation pathway, significant knowledge gaps remain in relation to storage costs and how storage may impact overall plant costs and operations. The decarbonisation pathway may also have broader infrastructure implications given the scale of these industries.	• Pilot and analyse integrated generation and storage technologies for different industrial processes to help identify low-cost pathways and their storage implications (to operations and local energy infrastructure).
Storage and distribution of hydrogen and hydrogen carriers	The storage and distribution of hydrogen and hydrogen carriers will be important to ensuring sufficient volumes are available at refuelling stations, for industrial applications and to support export operations. However, this will depend on export demand, domestic hydrogen industry development and how value chains are optimised. Given the time line related to Australia's ambition for hydrogen export and the domestic use of hydrogen to support decarbonisation, further analysis, piloting and demonstration will be required to help minimise technical and commercial risks related to storage and buffering.	• Analyse optimal distribution models and associated storage volumes required such that sufficient hydrogen (or hydrogen carriers) are stored to support export demand and are available for domestic applications and processes. • Pilot, demonstrate and scale up bulk and small-volume storage systems for hydrogen and its derivatives, as well as their integration into hydrogen distribution networks, to help de-risk projects across different end-use applications.

Greater levels of domestic and international engagement can help Australia establish domestic supply chains and de-risk and reduce the cost of renewable energy storage deployment.

Energy market and storage technology investments will need to be supported by a strong ecosystem of industry, government, research and community stakeholders working together to ensure that the most effective outcomes are achieved.

This will require strong engagement and collaboration to deliver effective policy, build consensus, develop storage technology supply chains and skills, and deliver RD&D that helps reduce costs and improves social and environmental outcomes. With growing global recognition about the importance of energy storage, international collaboration can accelerate progress by coordinating RD&D efforts, growing domestic capability and enhancing relationships with key trading partners.

- **Stakeholder engagement:** Collaboration between government, industry (including investors), research institutions and community will play an important role in choosing technology pathways and designing the future energy market.
- **International collaboration:** There is room for Australia to further participate in international energy storage dialogues and RD&D activities to support the development and deployment of energy storage systems in Australia and avoid duplication of effort and investment.
- **Cross-cutting R&D:** Further consideration of safety and testing, land use and environmental impact, skills and cross-cutting research will play a valuable role in supporting the adoption and scale up of storage technologies in Australia (see figure).

Enabling science and technology

Research in information and communication technologies and material sciences that enable energy storage technology development and enable efficient use of storage.

Modelling

Use of cutting-edge modelling to inform decision making across technology design and energy system design.

Environmental and social

Research in environmental impacts of energy storage value chains, technology improvements for resource circularity, consumer behaviour and acceptance, and community engagment to inform technology development and decision -making.

Safety, security, standards and testing

Research and development of tools to manage technology safety and environmental risks, ensure cybersecurity across the energy system, and facilitate testing and certification to bring products to market.

Introduction

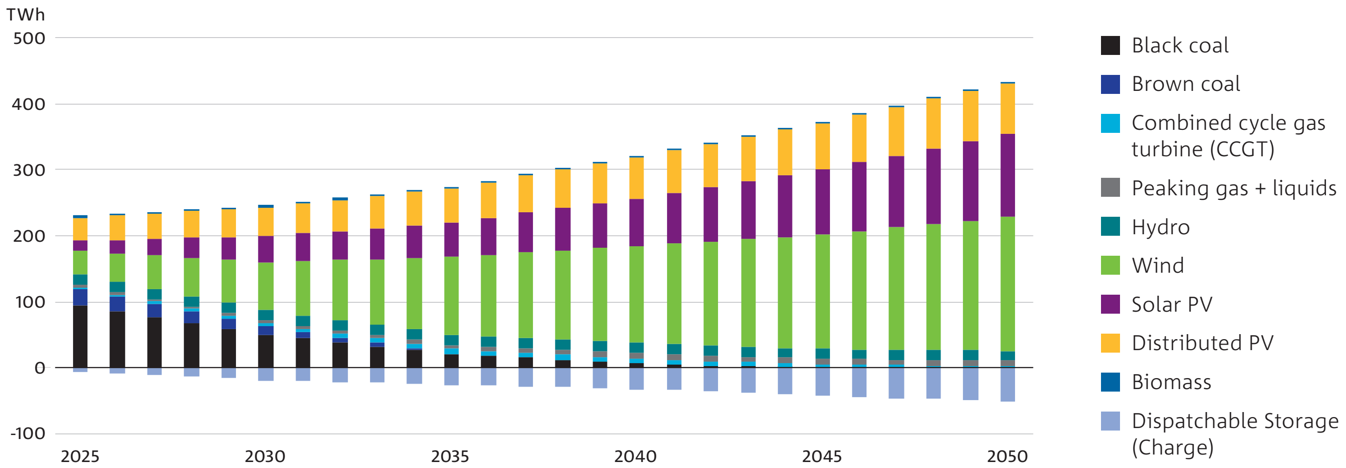
Storage of renewable energy is essential to ensure access to secure, reliable and affordable energy as Australia transitions to net zero.

‘Energy storage’ refers to a suite of systems and technologies that enables the decoupling of the time of energy generation and energy use. Existing energy storage systems for fossil fuels include coal stockpiling, line packing in gas pipelines and fuel tanks. The types of storage systems used will change as Australia transitions to net zero. This roadmap therefore considers the systems and technologies that will be important for the production, storage and utilisation of renewable energy.

The Australian Government has legislated a target for net zero greenhouse gas emissions by 2050, a transition that will result in significant changes across Australia’s energy system. First, Australia’s electricity generation mix is projected to become dominated by variable renewable energy (VRE), mainly in the form of wind and solar photovoltaic (PV; see Figures 1 and 2). In the *Step Change* scenario explored in this roadmap, the VRE share of electricity generation in the national electricity market (NEM) increases from 25% in 2020 to 64% by 2030 and to 94% by 2050. There is a similar trend in the VRE share of generation in Western Australia (WA), reaching 95% by 2050.[2]

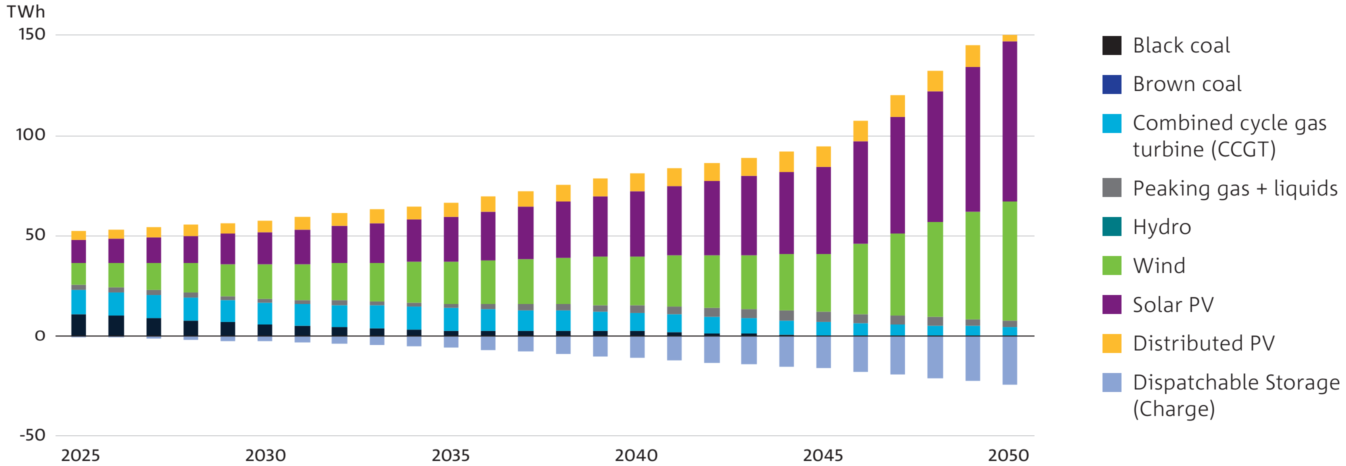
2 The share of renewable energy overall (including hydro and biomass) is expected to reach 98% in the NEM and 95% in WA by 2050. It should be noted that modest changes in assumptions about the timing and scale of industrial decarbonisation and growth could impact the timing and the scale of renewable electricity and associated energy storage uptake. This is a function of the greater proportion of industrial load relative to the NEM and the high proportion of off grid electricity demand present in WA.

Figure 1: Forecast electricity generation and storage in the NEM to 2050, *Step Change* scenario



Notes: Although customer (non-VPP) storage is not explicitly modelled in this framework, this could reflect up to 10.7 TWh of charge by 2050.
Terminology: CCGT, combined cycle gas turbine; NEM, national electricity market; PV, photovoltaic; VPP, virtual power plant.

Figure 2: Forecast electricity generation in WA to 2050, *Step Change* scenario



Notes: Although customer (non-VPP) storage is not explicitly modelled in this framework, this could reflect up to 3.4 TWh of charge by 2050.
Terminology: CCGT, combined cycle gas turbine; PV, photovoltaic; VPP, virtual power plant; WA, Western Australia.

There is also a large increase in total electricity demand between 2020 and 2050 (in the *Step Change* scenario, this is more than twofold in the NEM and nearly fourfold in WA), driven, in part, by the electrification of end-use sectors. In road transport, fossil fuel-based diesel and petrol are expected to be displaced by electricity, and there is some uptake of renewable fuels, such as 'green' hydrogen, for use in heavy vehicles. There will also be a shift towards electrification (and, in some cases, hydrogen) in buildings and industry. In addition, the production of green hydrogen for export will have an impact on the energy system due to the large amount of renewable electricity required for production, as well as the need to store and transport the product. As a result of these changes, the Australian economy will need to significantly increase its capacity to store renewable energy.

As Australia decarbonises and VRE deployment increases, a diversified range of storage systems will need to be adopted.[3] These include:

- electrochemical storage, which covers technologies such as lithium ion (Li-ion) batteries, which convert and store electricity in chemical form for a period of time that can then be reversed to release electricity back into the system.
- mechanical storage processes, such as pumped hydro energy storage (PHES),[4] that use gravity, acceleration or compression to store kinetic energy, which can generate electricity upon release.
- chemical storage, such as in the form of hydrogen in tanks or pipelines, in which energy is stored in the bonds of chemical compounds and released during a chemical reaction, such as the combustion of a fuel in an engine for a transport application or in a turbine for electricity.
- thermal storage, that convert and/or store an energy input (i.e. heat, electricity or concentrated solar thermal) in the form of thermal energy in a thermal medium (such as molten salts), which can be used at a later period as direct heat or to generate electricity.

Although the Australian Government has recognised energy storage as a priority in its *Powering Australia* plan, significant knowledge gaps remain that require further investigation to support informed action.[4] This includes a greater understanding of the scale and nature of Australia's storage needs across different decarbonisation scenarios and geographies, as well as the ability to deploy storage technologies in the electricity sector and different end-use sector contexts. Understanding these elements can reveal factors that influence investment decisions and inform future decision making.

3 Given the requirement to reach net zero, only renewable energy storage systems are considered. This refers to direct emissions from the process rather than the full life cycle emissions.

4 Australian Labor Party (2021) Powering Australia. <https://keystone-alp.s3-ap-southeast-2.amazonaws.com/prod/61a9693a3f3c53001f975017-PoweringAustralia.pdf> (accessed 19 October 2022).

This roadmap contributes to addressing knowledge gaps in the following ways:

- Building on the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP), this work uses energy systems and electricity sector models to **estimate electricity storage** across multiple scenarios out to 2050, extending the analysis to cover WA.
- Drawing on existing literature, this work develops **detailed energy storage technology summaries**, including understanding the level of maturity and deployment considerations.
- Although most existing analysis focuses on electricity storage, this work extends the scope to include **hydrogen and thermal energy storage** in key sectors. Although modelled net zero pathways for these storage categories are not included in this roadmap, a potential order of magnitude estimate for these forms of energy storage is included.
- This work outlines **energy storage requirements for specific sectors**, which involves examining the role of storage, technology options and deployment considerations for that sector.
- This work generates estimates for the **levelised cost of storage (LCOS)** to compare the current and potential cost competitiveness of different renewable storage technologies. The LCOS methodology outlines the clear boundaries for the inclusion of costs, which ensures transparency and comparability with other methods. A cost comparison with relevant fossil fuels in a particular sector (i.e. diesel or natural gas) is also included.
- This work develops **recommendations** for the scale up of renewable energy storage in Australia.

The Renewable Energy Storage Roadmap provides a starting point for decision makers across sectors, highlighting mature technologies that can be deployed today, as well as technologies that still need to be developed further to support Australia's net zero objectives.

This report was developed with the support of government and industry, and is based on an extensive literature review, expert consultations and CSIRO modelling and analysis. The report aims to support the coordinated investment in and scale up of renewable energy storage in Australia by generating discussion and communicating the uncertainties associated with different net zero energy pathways.

The report is divided into four main parts:

Part I – Australia's demand for renewable energy storage under net zero: Part I explores Australia's future demand for renewable energy storage systems consistent with net zero, including demand variations across Australian regions and key uncertainties related to renewable energy storage uptake.

Part II – Energy storage technology landscape: Part II introduces energy storage technology options used to consider sectoral storage requirements in Part III. It discusses maturity of the technologies considering technology and commercial readiness.

Part III – Sectoral energy storage requirements: Part III builds upon the storage demand modelling (Part I) and the energy storage technology landscape (Part II) to investigate the specific storage requirements for seven representative sectors in Australia. It identifies technology gaps and uncertainties and supported by techno-economic analysis, available technologies are assessed to understand their suitability in meeting storage requirements.

Part IV – Strategic priorities for energy storage: Part IV synthesises previous insights into an action plan for scaling up renewable energy storage in Australia, acknowledging the various uncertainties regarding future storage demands and end user requirements.

The appendices include further details on the list of stakeholders consulted for this project, the storage demand modelling approach, the approach to estimating the LCOS, the case study approaches and technology scans.

Energy storage terminology

Roadmap energy storage duration definitions

Although no universally agreed definition for storage duration categories exists, this project considers the energy storage technologies by duration categories to illustrate the projected demand and LCOS for specific storage duration needs (outlined in Table 1).

Table 1: Storage duration definitions

STORAGE TYPE	DURATION
Short	Storage less than 4 hours
Medium	Storage between 4 and 12 hours
Long intraday	Storage between >12 and 24 hours
Long multiday	Storage between >24 and 100 hours
Seasonal	Storage more than 100 hours

Roadmap definitions for maturity

The LCOS approach groups storage technologies by maturity to improve understanding as to which technologies can be used to meet short-term requirements and those that may be more appropriate for long-term needs. Although maturity levels are predominantly assessed using the commercial readiness index (CRI), the technological readiness level (TRL) is used to understand the nuances between technologies that are at a lower CRI level. Definitions for maturity levels are provided in Table 2.

Table 2: CRI and TRL definitions

CRI/TRL	ROADMAP	DEFINITION
CRI 5–6	Competitive commercial deployment	Bankable asset class or market competition driving widespread deployment
CRI 4	Supported commercial deployment	Deployment of multiple commercial applications with government support
CRI 3	Commercial-scale demonstration	Commercial scale up supported by equity finance and government support
CRI 1–2 **TRL 7–9**	Pilot-scale demonstration	Commercial trial supported by equity and government support, or technically ready but commercially untested
CRI 1 **TRL 2–7**	RD&D	Research, development and demonstration

Part I: Australia’s demand for renewable energy storage under net zero

This analysis uses a scenario-based approach to illustrate the range of potential pathways for renewable energy storage as Australia transitions to net zero.

This roadmap models the uptake of renewable electricity storage across the NEM and across WA that is consistent with Australia’s net zero by 2050 target. The AusTIMES energy systems model and STABLE electricity sector model are used to develop quantitative pathways for electricity storage. Although detailed modelling for other forms of renewable energy storage (hydrogen and thermal storage) is not covered in this report, a simple approach is included to illustrate the potential order of magnitude for these forms of energy storage.

The role of renewable energy storage in meeting Australia’s net zero ambitions is explored through two contrasting scenarios aligned to the AEMO’s 2022 ISP. The *Step Change* and *Hydrogen Superpower* scenarios were chosen from four possible futures that could materially impact Australia’s energy sector.[5] *Step Change* was selected because the AEMO identified this scenario as being the most likely for Australia of those considered.[6]

The *Step Change* scenario sees a consistent and fast-paced transition from fossil fuels to renewable energy through coordinated economy-wide action, a falling cost of VRE and energy storage, and global policy commitments consistent with limiting global temperature increases to below 2°C by 2100.

In the *Hydrogen Superpower* scenario, global policy ambition is stronger, limiting global temperature increases to 1.5°C by 2100. There is also strong domestic economic growth, with Australia leveraging its competitive advantage in green hydrogen and other low-emissions industrial exports. *Hydrogen Superpower* is an important scenario to explore given the large impact hydrogen production can have on electricity demand and because the presence of flexible hydrogen electrolysers in an electricity system can substantially reduce electricity storage required for a given VRE capacity. The *Hydrogen Superpower* scenario also presents new challenges in storing very large quantities of hydrogen.

To support national discussions, this roadmap extends AEMO’s ISP scenario assumptions to WA and incorporates state-level plans, such as the shutdown of state-owned coal power plants by 2030.[7] The modelled scenarios for the power sector include the NEM and WA markets, considering the South West Interconnected System, the North West Interconnected System, inland Pilbara, Gascoyne–Mid-west and Goldfields–Esperance area. This covers around 98% of Australia’s electricity generation.

There have been further developments impacting the energy market since the original scenarios were developed for AEMO’s 2022 ISP. Although some of these have been integrated into the modelling approach, others could not be incorporated (see Appendix B for all updates and exclusions).

5 AEMO (2022) 2022 Integrated system plan. <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp> (accessed 19 October 2022).

6 A Delphi process was used in which stakeholders anonymously selected the *Step Change* scenario.

7 Government of Western Australia (2022) State-owned coal power stations to be retired by 2030 with move towards renewable energy. <https://www.wa.gov.au/government/announcements/state-owned-coal-power-stations-be-retired-2030-move-towards-renewable-energy> (accessed 19 October 2022).

1.1 Electricity storage terminology

As Australia transitions to net zero, there will be an increase in demand for electricity storage of varying durations. In this section we outline the durations considered and the appropriate measurement for energy storage uptake.

'Duration' refers to the amount of time the storage can be discharged at full power before being depleted. Although short-duration storage is required to balance short-term deviations in energy demand and supply, medium- to long-duration storage will become more important in managing system reliability at very high levels of variable renewable penetration. Table 3 builds on the storage terminology provided earlier (see Energy Storage Terminology in the Introduction) and presents the types of storage included in each definition, as well as how these map to the categories used in the AEMO 2022 ISP.

For simplicity, this section refers to any storage solution (e.g. electrochemical, mechanical, chemical and thermal) that can be used to manage imbalances in electricity supply and demand as 'electricity storage'. Demand for hydrogen and thermal energy storage in this section refers to the storage and buffering of hydrogen or heat respectively.

The analysis estimates storage uptake for each of the duration categories on both a power capacity (GW) and energy capacity (GWh) basis. When considering a specific storage system, 'power capacity' refers to the maximum instantaneous discharge capability (e.g. 2 GW). This can be used alongside storage duration to estimate energy capacity, which shows the maximum amount of stored energy once accounting for storage duration. For example, a battery with a 2-GW power capacity and a duration of 8 hours will have an energy capacity of 16 GWh. However, note that given there are technical limitations on the depth of discharge, utilisation rates (which vary by duration) also need to be applied to energy capacity to calculate usable energy capacity.

Although GW capacity is important in illustrating the magnitude of the power generation shortfalls that can be addressed with storage at any one time, GWh capacity is important for showing the ability to address energy shortfalls that persist over a period of time. For example (assuming for simplicity that utilisation is 100%), a 500-MW PHES plant, with a duration of 2 days, is not able to address a simultaneous 700-MW shortfall in power generation, but it could provide the energy needed to address a 500-MW power generation shortfall that persists over 2 days (equivalent to 24 GWh). In contrast, 700 MW of Li-ion batteries, with an energy capacity of 2.8 GWh, could address a 700-MW shortfall in power generation if it were to persist for only 4 hours, but could not address a shortfall of this magnitude over longer periods.[8]

Table 3: Electricity storage duration definitions

STORAGE TYPE	DURATIONS	AEMO ISP 2022
Short	Storage of less than 4 hours • Customer (non-VPP): Customer-owned storage to support own load (not coordinated to deliver grid services) • VPP: Customer-owned storage, coordinated to deliver services to the grid • Utility scale, coordinated storage	'Distributed storage' (equivalent to Customer, non-VPP) 'Coordinated DER storage' (VPP component) <4 hours: 'shallow storage'
Medium	Storage between 4 and 12 hours • V2G: Customer-owned storage from EV batteries can export electricity to the grid or other behind-the-meter loads • Utility scale, coordinated storage	'Coordinated DER storage' (V2G component) 4–12 hours: 'medium storage'
Long intraday	Storage between >12 and 24 hours • Utility scale, coordinated storage	12+ hours: 'deep storage'
Long multiday	Storage between >24 and 100 hours • Utility scale, coordinated storage	12+ hours: 'deep storage'
Seasonal	Storage more than 100 hours • Utility scale, coordinated storage	12+ hours: 'deep storage' 168 hours: Snowy 2.0 PHES

Notes: EV, electric vehicle; DER, distributed energy resources; V2G, vehicle to grid; VPP, virtual power plant.

8 However, a 700-MW or 2.8-MWh battery could, for example, provide 350 MW of energy over 8 hours.

The modelling results suggest that a wide range of projects of varying power capacity and duration will be required. These are aggregated by storage type (listed in Table 3) and reported in section 1.2. Although the focus of this analysis is on 'dispatchable' storage, which refers to storage capacity that can vary energy supply at the command of the operator,[9] customer (non-VPP) storage, which is not coordinated by the grid, is also included in the projections.

1.2 Demand for electricity storage

Electricity storage can be used in a number of ways to support the supply of safe, reliable and cost-effective electricity to Australia's electricity grids (for more details, see Section 3.2). This section quantifies the electricity storage uptake in each of the scenarios considered based on duration (see Table 3), size (customer or utility scale) and, in the case of customer storage, type of battery (non-VPP, VPP or V2G).[10]

Step Change scenario

In the *Step Change* scenario, demand for renewable energy storage capacity is expected to grow significantly, underpinned by growth in VRE deployment.

Given that in the *Step Change* scenario the majority of electricity will be generated from VRE by 2030, a significant increase in energy storage is required to manage the associated seasonality and intermittency. NEM demand for dispatchable electricity storage in the *Step Change* scenario is expected to grow to 13 GW/420 GWh in 2030 and to 44 GW/550 GWh in 2050 (see Figure 3). Demand for dispatchable storage in WA is expected to grow from low levels today to 1 GW/7 GWh by 2030 and to 12 GW/74 GWh of capacity by 2050 (see Figure 4).

This scale of dispatchable electricity storage in the NEM largely aligns with the AEMO's 2022 ISP, which reports electricity storage demand of 46 GW/640 GWh across the NEM by 2050. The difference in GWh is driven, in part, by different projections for storage duration, with a longer average duration underlying the AEMO's ISP.

Including estimates for customer (non-VPP) storage (dashed bars in Figures 3 and 4),[11] total electricity storage in the *Step Change* scenario is expected to grow to 58 GW/580 GWh by 2050 in the NEM (Figure 3), and to 17 GW/83 GWh of capacity by 2050 in WA (Figure 4).

In the *Step Change* scenario, customer-owned batteries (VPP and V2G) are expected to play a large role in dispatchable storage in the NEM, whereas there is greater uptake of utility scale storage in WA. By 2050, customer-owned storage is projected to account for around 70% and 35% of dispatchable power capacity (GW) requirements in the NEM and WA respectively. The expectation for a higher customer-based storage share in the NEM relative to WA is due to a higher ratio of population to industrial output.

Although there is a large uptake in customer-based dispatchable storage in the NEM under the *Step Change* scenario, alternative projections consistent with net zero are also possible. For example, a sensitivity was analysed to understand what would happen if a large proportion of customers choose not to have their home batteries or battery electric vehicles (EVs) dynamically coordinated by the grid. The sensitivity found that customer-based dispatchable batteries could be replaced with much lower levels of medium-duration utility scale storage. Therefore, although the availability of customer-based dispatchable storage provides benefits to utilities, the impact from lower levels of uptake is small (see Appendix B for more details on this sensitivity).

The NEM sees an uptake of seasonal storage driven by the introduction of Snowy Hydro 2.0 in 2026.[12] Therefore, from 2030, energy capacity (GWh) is dominated by seasonal storage in the NEM. This is not evident in WA because, due to climate and geographical constraints, the reservoirs are assumed to be too small to make long- or seasonal-duration PHES cost-effective. WA also does not see any uptake of long-duration storage because, in the *Step Change* scenario, gas peakers are still expected to address VRE shortfalls of long and seasonal duration in 2050 (projected to be 8% of installed capacity but only 2% of generation due to infrequent use). The emissions from gas are fully offset by carbon capture, utilisation and storage (CCUS) and land-based sequestration to achieve net zero.

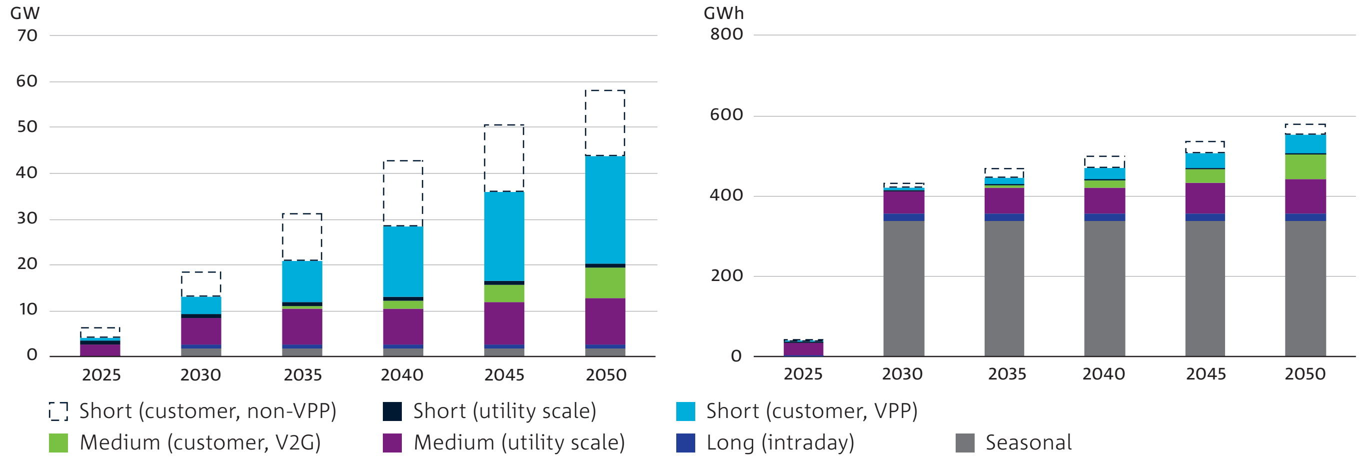
9 Lovegrove K, James G, Leitch D, Milczarek A, Ngo A, Rutovitz J, Watt M, Wyder J et al. (2018) Comparison of dispatchable renewable electricity options. ITP Thermal, Turner. <https://arena.gov.au/assets/2018/10/Comparison-Of-Dispatchable-Renewable-Electricity-Options-ITP-et-al-for-ARENA-2018.pdf> (accessed 21 October 2022).

10 The modelling framework does not include the ancillary service market.

11 For the NEM, these projections are sourced from the 'distributed' storage projection in AEMO's 2021 ISP. For WA, the projections are sourced from: Graham P (2021) Small-scale solar and battery projections 2021. <https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2021/CSIRO-DER-Forecast-Report> (accessed 20 October 2022).

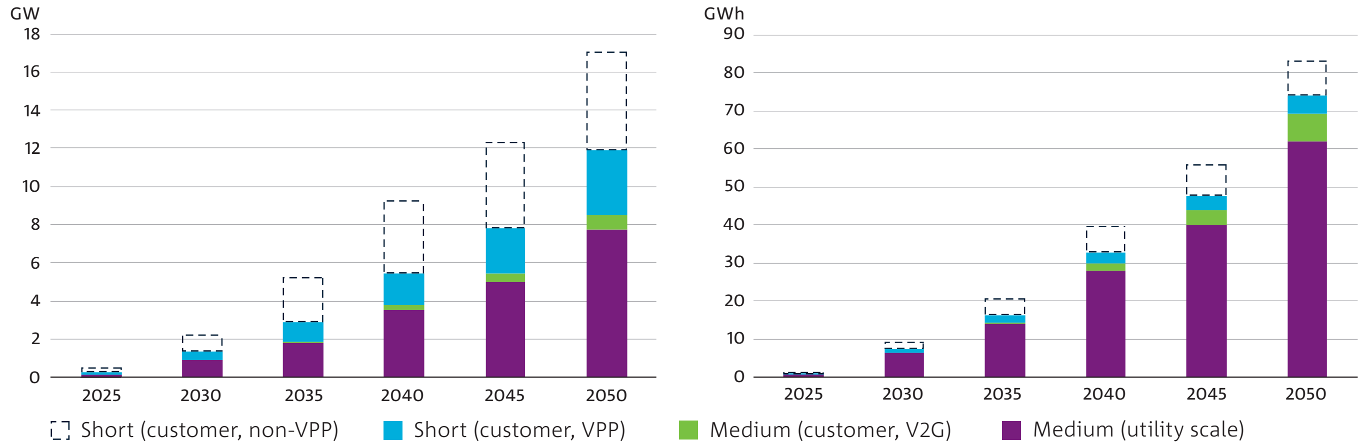
12 This is included as a committed project, rather than being chosen as the least-cost option through the modelling process.

Figure 3: NEM electricity storage capacity, Step Change scenario



Notes: Estimates are based on a least-cost modelling approach to achieve net zero emissions at a national level, rather than a jurisdictional level (see Appendix B for more details). Dashed bars reflect customer (non-VPP) storage sourced from AEMO's 2022 ISP. Terminology: NEM, national electricity market; V2G, vehicle to grid; VPP, virtual power plant.

Figure 4: WA electricity storage capacity, Step Change scenario



Notes: Estimates are based on a least-cost modelling approach to achieve net zero emissions at a national level, rather than a jurisdictional level (see Appendix B for more details). Dashed bars reflect customer (non-VPP) storage sourced from AEMO's 2022 ISP. Terminology: V2G, vehicle to grid; VPP, virtual power plant; WA, Western Australia.

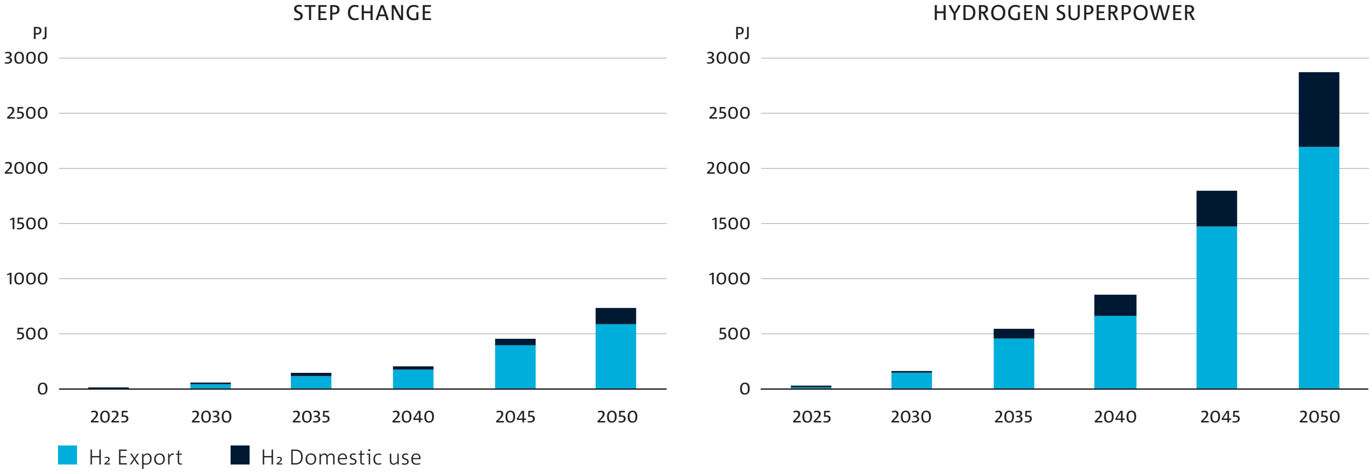
Hydrogen Superpower scenario

The *Hydrogen Superpower* scenario sees a large increase in the production of hydrogen, supported by electricity storage systems.

Hydrogen Superpower considers a scenario where the production of hydrogen reaches 2,845 PJ/790 TWh by 2050, compared with 740 PJ/205 TWh in the *Step Change* scenario.[13] A large share of hydrogen production is expected to be for export, with an assumption of 2,175 PJ/604 TWh of hydrogen exports by 2050 incorporated into the modelling approach (Figure 5).[14]

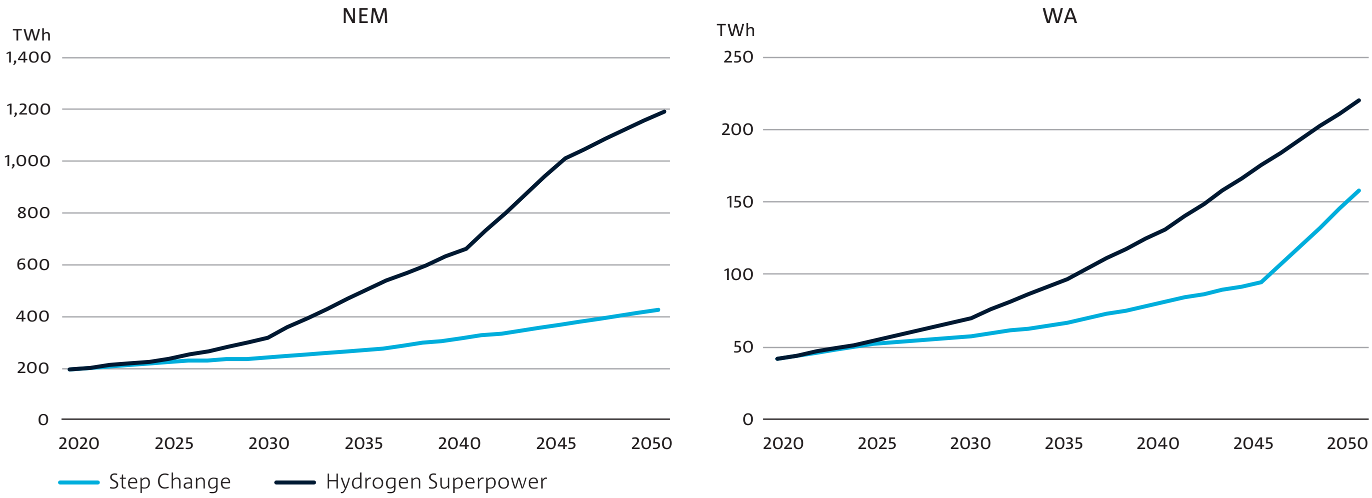
The demand for electricity storage is much higher in the *Hydrogen Superpower* scenario than in the *Step Change* scenario because hydrogen production via electrolysis requires large amounts of VRE for continuous production. As a result, there is a much stronger outlook for electricity demand, with a sixfold increase in electricity demand across the NEM between 2020 and 2050, compared with a twofold increase in the *Step Change* scenario (Figure 6).

Figure 5: Hydrogen production (export and domestic use of hydrogen) by scenario to 2050



Notes: To convert PJ to TWh, multiply by 0.277778.

Figure 6: Electricity generation in the NEM and WA by scenario to 2050



Terminology: NEM, national electricity market; WA, Western Australia.

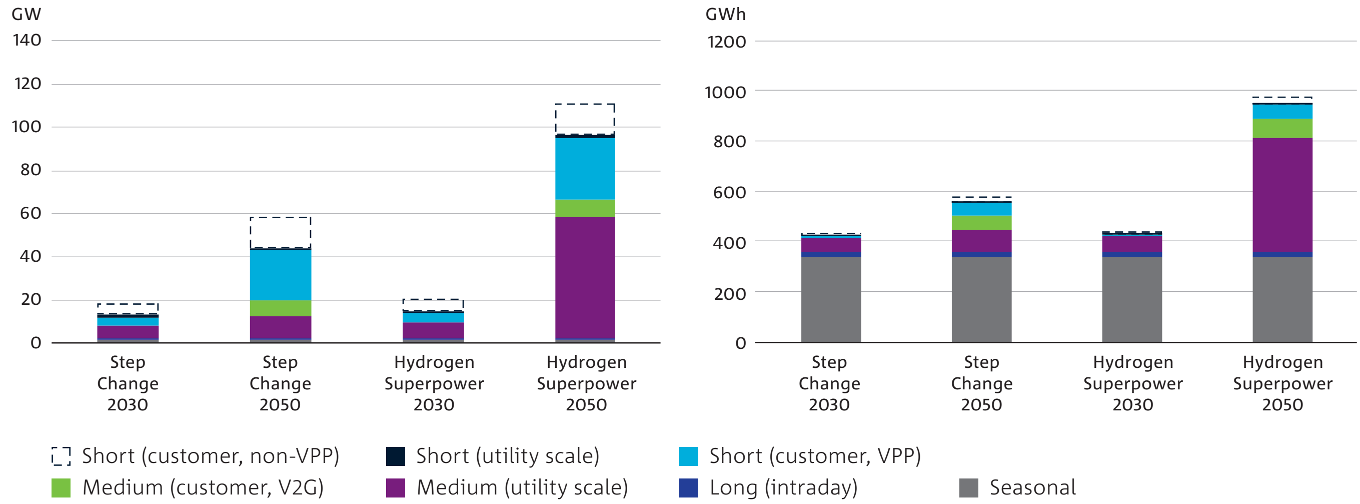
13 This is equivalent to 20 and 5 Mt of hydrogen respectively.

14 This is equivalent to 15 Mt of hydrogen.

The change in electricity demand between these two scenarios, alongside high VRE uptake, results in NEM dispatchable electricity storage more than doubling under the *Hydrogen Superpower* scenario compared with the *Step Change* scenario by 2050. The *Hydrogen Superpower* scenario suggests that the NEM and WA could require up to 96 GW/950 GWh and 17 GW/96 GWh of dispatchable electricity storage respectively by 2050 (Figures 7 and 8).

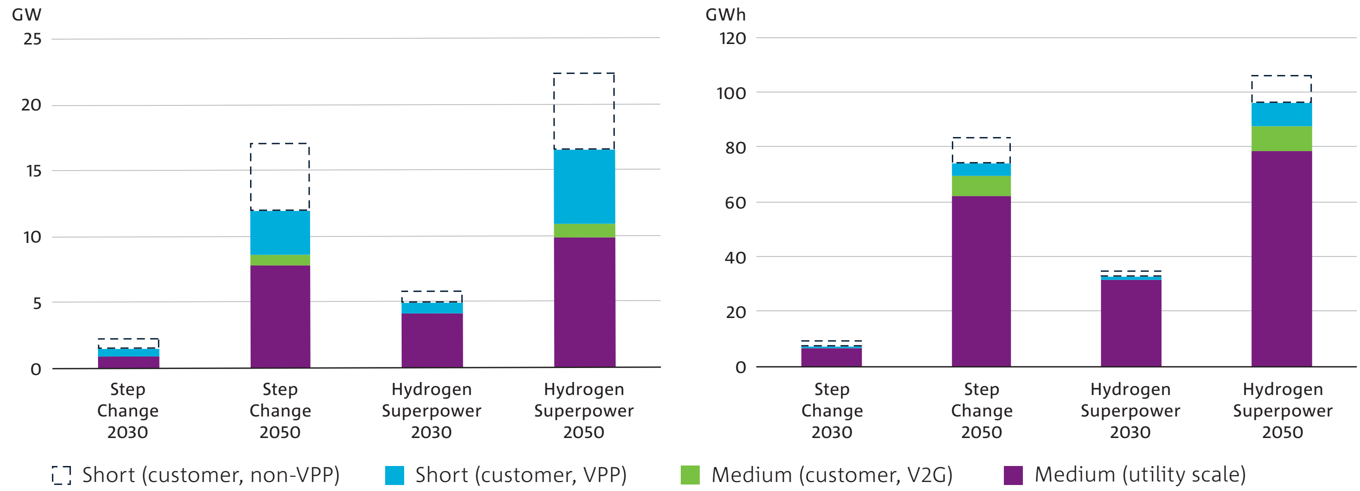
Relative to the *Step Change* scenario, a greater share of the storage is expected to be of medium duration in the NEM. This is because hydrogen producers benefit from medium-duration storage smoothing out renewable supply.[15] The storage requirements do not increase to the same degree in WA compared with the NEM. This is partly because hydrogen production is assumed to account for a smaller share of electricity demand in WA

Figure 7: NEM electricity storage capacity, scenario comparison



Notes: Estimates are based on a least-cost modelling approach to achieve net zero emissions at a national level, rather than a jurisdictional level (see Appendix B for more details). Dashed bars reflect customer (non-VPP) storage sourced from AEMO's 2022 ISP. Terminology: NEM, national electricity market; V2G, vehicle to grid; VPP, virtual power plant.

Figure 8: WA electricity storage scenario comparison



Notes: Estimates are based on a least-cost modelling approach to achieve net zero emissions at a national level, rather than a jurisdictional level (see Appendix B for more details). Dashed bars reflect customer (non-VPP) storage sourced from AEMO's 2022 ISP. Terminology: V2G, vehicle to grid; VPP, virtual power plant; WA, Western Australia.

15 Hydrogen producers have little need for long-duration storage because long shortfalls in power generation are expected to occur infrequently and electrolysers can ramp down to around 5% generation when required.

16 This is because WA does not have significant medium-duration pumped hydro resources, which are the lowest cost source of medium-duration storage in other states.

relative to the NEM. In addition, WA faces higher electricity storage costs,[16] and so it is more cost-effective to have a lower utilisation of electrolysers (and incur higher capital costs) than investing in large additions to electricity storage capacity. This, in turn, would lead to a large requirement for buffer storage for the hydrogen itself.

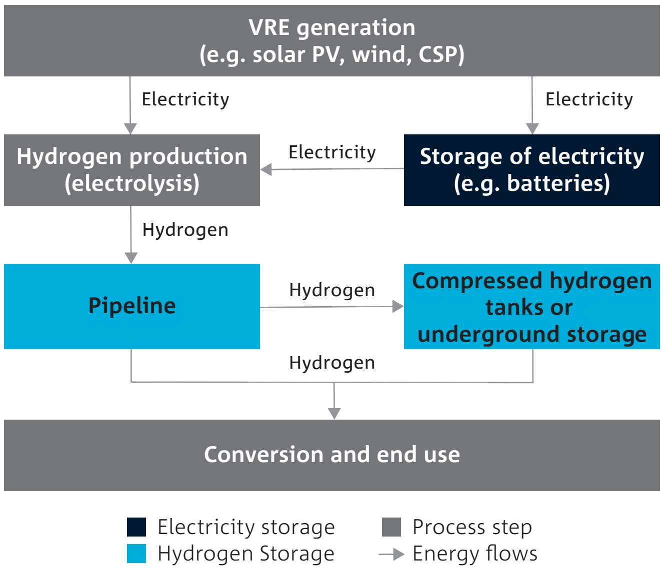
In both the *Step Change* and *Hydrogen Superpower* scenarios, the storage capacity requirements for WA are subject to a significant degree of uncertainty owing to a number of unique factors in the state. WA is more exposed to changes in Australia's future exports as WA accounts for the majority of mineral exports. Furthermore, as industries look to electrify to substitute their gas and diesel consumption, the percentage increase in renewable generation and storage requirements relative to existing capacity is much larger relative to other states where the industrial sectors are a smaller part of their total electricity demand. Consequently, modest changes in assumptions about the timing and scale of industrial decarbonisation and growth in WA will likewise result in a significant range of results in terms of the timing and scale of demand for storage. As an example, Section 3.6 discusses different decarbonisation pathways in alumina refining and, while not modelled, it provides a case study that explores the potential scale of energy storage required in south-west WA to decarbonise the refineries using electrification and hydrogen.

Although the absolute level of storage is higher under the *Hydrogen Superpower* scenario, the NEM requires much less dispatchable storage relative to the level of variable renewable capacity because hydrogen electrolysers can reduce their load down to around 5% capacity in the presence of energy shortfalls. This implies that proportionally less storage is required to balance a system in cases where hydrogen demand makes up a significant share of total electricity demand. In the *Step Change* scenario, the ratio of total storage capacity to variable renewable capacity in 2050 in the NEM is 0.33, compared with 0.23 in the *Hydrogen Superpower* scenario.

The modelling results illustrate that hydrogen producers have a choice regarding how to utilise storage to support production. They could either deploy electricity storage before the actual production process or ramp electrolysers up and down, and then store the produced hydrogen in various forms (Figure 9; see Section 3.7 for more details).

To explore how this choice may be impacted further, a sensitivity was developed to understand the impact on electricity storage in an extreme case, where the *Hydrogen Superpower* production target is still achieved but with a much lower cost for hydrogen storage. The sensitivity resulted in lower electricity storage requirements because it was more cost-effective to reduce the use of electricity storage and increase capital spending on electrolysers (run at lower utilisation rates). It was estimated that, across the NEM, access to low-cost hydrogen storage could reduce dispatchable electricity storage requirements by up to 50% (see Appendix B for more details on this sensitivity). The implication is that further developments in the cost of storing hydrogen (or a derivative) could have a large impact on the demand for electricity storage.

Figure 9: Storage options in hydrogen production



Terminology: PV, photovoltaic; VRE, variable renewable energy.

Modelled scenarios versus existing plans

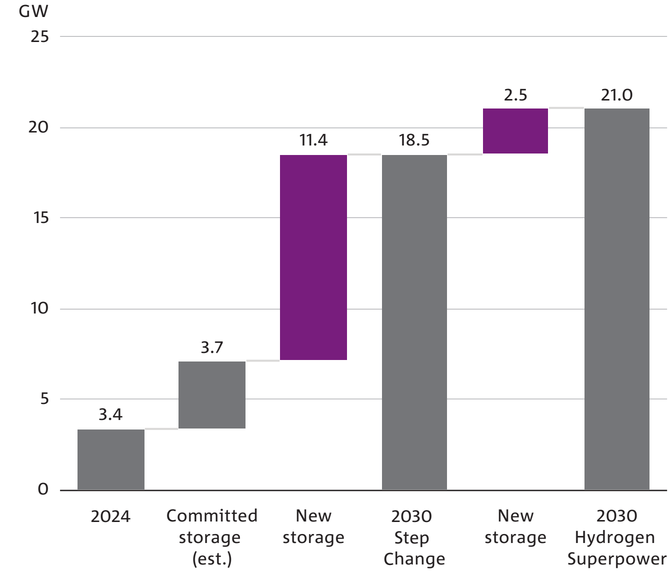
Comparing the scenario projections for electricity storage with existing plans for supply suggests there is a gap that needs to be filled to meet Australia's 2030 requirements.

The scenario results suggest that, across the NEM, an additional 11–14 GW/59–69 GWh of storage capacity will be required by 2030 (Figure 10). Large, committed energy storage projects to 2030 only account for around 3.7 GW. This includes 3 GW of PHES, comprising the Snowy 2.0 (2,000 MW), Kidston (250 MW) and Cethana (750 MW) projects.[17] In addition, roughly 700 MW of short-duration energy storage capacity has been committed to by 2024 across the NEM.

Although there is a large gap in power capacity between planned projects and expected demand, the majority of the gap to 2030 is projected to be customer owned, which cannot be tracked in the same way as utility scale commitments. However, should customer-owned storage projections be lower than expected, the task will fall to utility scale developers. Where utility scale storage deployment is required by 2030, the projects would require planning, approvals, and investment decisions to occur in the near term to provide sufficient time for demonstration and project development.

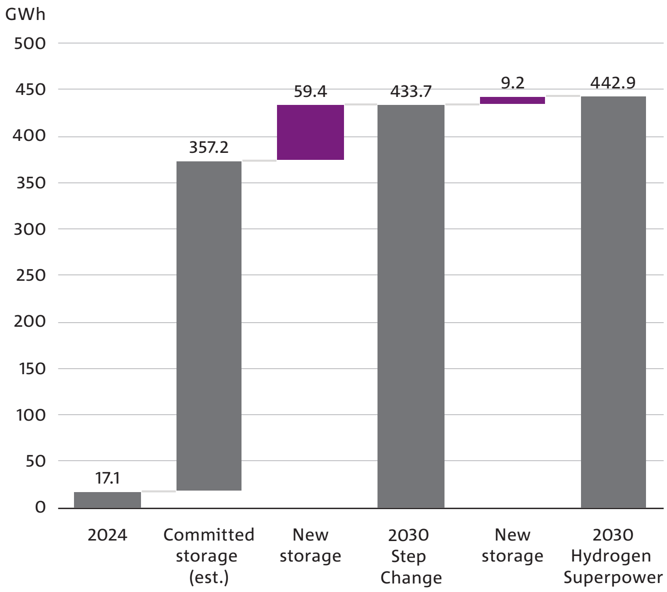
The capacity gap is mainly for short and medium durations. Although there are existing technologies that can supply storage at these durations (see Section 3.2), there are a number of barriers to uptake that could still make meeting the requirements difficult. With Snowy 2.0 expected to come online by 2026,[18] there is a minimal gap projected for long- to seasonal-duration storage and, given these technologies make up a large proportion of energy capacity (GWh), the gap by 2030 is projected to be small based on this metric (Figure 11).

Figure 10: NEM electricity, power capacity: 2024 versus 2030



Notes: Electricity storage capacity estimates for 2024 are sourced from AEMO's 2022 ISP. Terminology: NEM, national electricity market.

Figure 11: NEM electricity storage, energy capacity: 2024 versus 2030



Notes: Electricity storage capacity estimates for 2024 are sourced from AEMO's 2022 ISP. Terminology: NEM, national electricity market.

17 Although Cethana is still classed as a 'new-generation technology' by the AEMO, it has been included in the storage projections. Although there are also two pumped hydro projects in Queensland that have recently been announced (Pioneer-Burdekin and Borumba Dam), these are not expected to be complete until 2035: Queensland Government (2022) World's biggest pumped hydro for Queensland. <https://statements.qld.gov.au/statements/96233> (accessed 18 November 2022).

18 Snowy Hydro (n.d.) Snowy 2.0 progress. <https://www.snowyhydro.com.au/snowy-20/progress/> (accessed 12 October 2022).

1.3 Demand for hydrogen and thermal energy storage

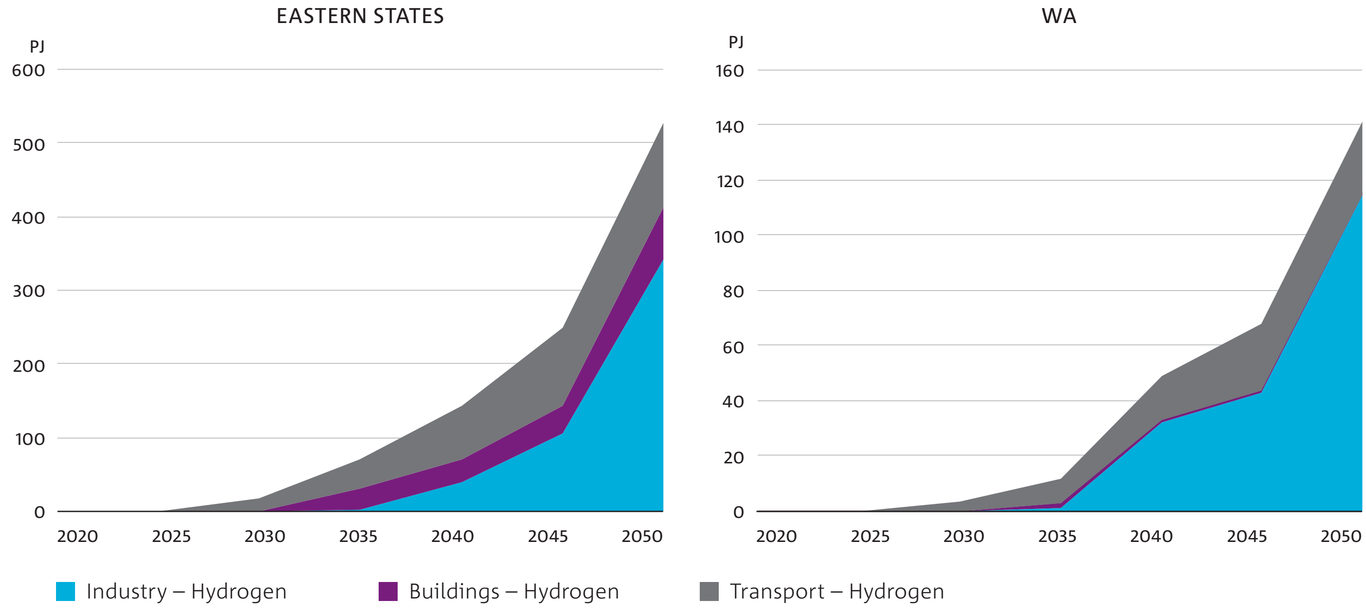
There is the potential for large increases in hydrogen and thermal energy storage in a net zero scenario.

In addition to helping meet Australia's demand for electricity storage, hydrogen storage will be required for distribution and buffering for various end users, and thermal energy storage will be needed when renewable process heat is used in industrial production. This report does not include detailed modelling of thermal energy and hydrogen storage demand, but a simple estimation approach can provide a potential order of magnitude for these storage systems. The results of this approach are summarised for the *Hydrogen Superpower* scenario.

Hydrogen storage

The *Hydrogen Superpower* scenario sees a large increase in hydrogen production for export (see Figure 5), which will require hydrogen storage systems to distribute and provide buffering for end users. Although the strong profile for hydrogen production is driven primarily by exports, the *Hydrogen Superpower* scenario also predicts a large increase in hydrogen use for domestic production, particularly in heavy-duty transport and industry applications (Figure 12). These applications will also require storage systems if hydrogen is produced in a separate location to end use (see Section 3.8 for hydrogen storage for heavy-duty transport, and Sections 3.5 and 3.6 for more details on other industrial applications of hydrogen storage).

Figure 12: Domestic hydrogen use by sector and region, *Hydrogen Superpower* scenario



Notes: To convert PJ to TWh, multiply by 0.277778. NEM states include New South Wales, Victoria, Queensland, South Australia, the Australian Capital Territory and Tasmania. Terminology: WA, Western Australia.

For every project, the optimal amount of hydrogen storage will depend on the variability of production, the cost of adding additional storage and the losses incurred in production. Heavy vehicle supply will need a buffer of storage to allow for dips in production and to cover the variable demand for refuelling. Large chemical conversion processes using hydrogen (e.g. ammonia synthesis) are difficult and costly to shut down and restart, so a substantial buffer of storage will be justified. To estimate an order of magnitude for the overall storage requirement, it has been assumed that a minimum average buffer equivalent to 24 hours of production can be taken as an approximate indication.

In the *Hydrogen Superpower* scenario, 2,845 PJ per year or 7.8 PJ per day of renewable hydrogen is produced in 2050. This implies a hydrogen storage capacity of 7.8 PJ, which is equivalent to 2,165 GWh or 54,950 tonnes of hydrogen for a storage duration of 24 hours. To compare the size of hydrogen storage on an equivalent basis to electricity storage, the estimate is adjusted back to electricity using an equivalent conversion efficiency.[19] This results in an estimated equivalent electricity storage capacity of 1,300 GWh for hydrogen storage, which exceeds the estimated electricity storage requirements in the *Hydrogen Superpower* scenario (950 GWh in 2050).

Thermal energy storage

Renewable thermal energy storage is expected to play a role in supporting industry decarbonisation where process heat is used in production. Sectors that use process heat include iron and steel, cement, alumina and food and beverage manufacturing (see Section 3.5 for more details on applications in manufacturing, and Section 3.6 for applications in alumina). Currently, an estimated 55% of energy use in industry is for the production of process heat, with the majority of this energy derived from fossil fuels.[20]

As Australia transitions to net zero, there will be a shift away from fossil fuels and towards the use of electricity generated from various renewable resources. In this case, thermal energy storage technologies can support the requirement for constant heat supply to compensate for variations in renewable energy input.

The modelled increase in industry electricity use under net zero, alongside other simplifying assumptions, can be used to approximate the size of renewable thermal energy storage in 2050. In the *Hydrogen Superpower* scenario, for states in the NEM, industry electricity use grows by 385 PJ per year between 2020 and 2050 (excluding the impact of industrial growth). We assume that the current share of energy use for process heat remains constant, and therefore assign 55% of the electricity increase to process heat (213 PJ per year by 2050). Converting this annual electricity use to daily use, gives an average of around 0.6 PJ per day or 160 GWh per day.

For industrial energy users, the optimal amount of thermal storage will be that which balances the investment in storage with the benefit from accessing electricity at times when it is more available and lower cost. Given industrial users often have a 24/7 heat load and electricity prices have regular daily peak periods, for this calculation it was assumed that a buffer storage equal to 12 hours average demand. This implies a renewable thermal energy storage capacity of around 80 GWh in 2050 for states in the NEM (for comparison, electricity storage is around 950 GWh in 2050). Conducting a similar exercise for WA results in an estimated renewable thermal energy storage capacity of around 70 GWh in 2050 (compared with 96 GWh of electricity storage in 2050). For more details on the calculation process, see Appendix B.

19 Assuming 1 GWh of hydrogen storage is equivalent to 0.6 GW of electricity storage. This is based on the conversion efficiency from hydrogen to electricity via a fuel cell, which is approximately 60%: IEA (2019) The future of hydrogen. <https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf> (accessed 22 November 2022).

20 This share is based on the current split between energy use for heat and heat use for other purposes (excluding feedstocks) in Lovegrove K, Alexander D, Bader R, Edwards S, Lord M, Mojiri A, Rutovitz J, Saddler H, Stanley C, Urkalan K, Watt M (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/renewable-energy-options-for-industrial-process-heat.pdf> (accessed 21 October 2022)

1.4 Key takeaways

The modelling results suggest that larger investments in short- and medium-duration electricity storage are required to reach net zero by 2050, and that significant investments in hydrogen storage systems would be required if Australia is to be a leader in green hydrogen exports.

The *Step Change* scenario demonstrated that a large increase in electricity storage would be required to meet the levels of VRE projected to be in Australia's energy system by 2050, particularly for short and medium durations.

The *Hydrogen Superpower* scenario illustrates that the requirement for electricity storage could be much higher again if there is a strong profile for green hydrogen production. Electricity storage in this scenario is estimated to be more than twice that in the *Step Change* scenario by 2050, with a larger requirement for medium-duration storage. Such a scenario would also require significant capacity for the storage of hydrogen.

Investment is also likely to be required for thermal storage systems, given uptake has the potential to be large in power and heavy industry applications.

Given the outlook for energy storage will depend on a range of factors that are uncertain, it is important to acknowledge other factors not explored in this analysis that could alter the projected uptake of energy storage, such as:

- the **outlook for global hydrogen demand** can vary considerably and is an exogenous model input in the *Hydrogen Superpower* scenario[21]
- the **barriers to electrification in industry** (the lower the barriers, the higher the VRE demand; this will, in turn, impact the need for electricity storage)[22]
- the **energy supply requirements of specific industry sectors** (e.g. some may not require energy supply at night)
- the **mode of delivery for hydrogen** (via pipeline or powerline)[23]
- the level of **investment in Australia's transmission and distribution infrastructure**.[24]

Despite the range of possible energy storage outcomes, all net zero pathways will require large investments to increase renewable energy storage capacity.

21 Forecast global hydrogen demand has been explored by numerous bodies and consulting services, with results varying drastically depending on market assumptions and scenario predictions. For an overview of forecast global hydrogen demand across Deloitte, IEA, ACIL Allen, IRENA, and the Hydrogen Council, see: Deloitte (2020) ERRATUM: Australian and global hydrogen demand growth scenario analysis. COAG Energy Council – National Hydrogen Strategy Taskforce. <https://www.dcceew.gov.au/sites/default/files/documents/erratum-coag-report.pdf> (accessed 28 October 2022).

22 Equivalently, a higher cost of land-based sequestration could lead to an increase in emissions abatement via electrification in industry.

23 If renewable electricity can be transported long distance via electric cables to produce clean hydrogen onsite, then electricity storage will be important. However, if it is more appropriate to produce hydrogen at a dedicated offsite centralised facility and transport it via a gas pipeline, this will require a greater uptake of hydrogen storage systems. This decision will depend on economic viability, onsite production considerations (e.g. geographical footprint, safety etc.) and geographical constraints favouring one system over the other.

24 In the *Step Change* scenario, 10,000 km of new transmission infrastructure will be required across the NEM by 2050 to connect geographically and technologically diverse generation and firming systems. In recognition of this requirement, the Australian Government has committed to invest A$20 billion in transmission infrastructure as part of its Rewiring the Nation policy, which aims to rebuild and modernise the grid to properly integrate the growing renewable's sector: Australian Labour Party (n.d.) Rewiring the nation: More jobs, lower power prices. <https://alp.org.au/policies/rewiring_the_nation> (accessed 26 July 2022).

Part II: Energy storage technology landscape

There is a range of storage technology options, both commercial and under development, with different strengths and weaknesses and levels of maturity.

The demand for energy storage discussed in Part I is also reflected in other countries, leading to a rapidly changing energy storage technology landscape globally. This section provides an overview of a range of storage technology systems under four energy storage technology classes[25] depending on how energy is stored and converted into usable forms (see Figure 13).

These technologies have been prioritised through consultation with experts across industry and the research sector and are discussed further in the context of sectoral applications (see Part III). Many of these technologies have been explored further in individual technology scans that explore benefits and limitations, deployment considerations and storage characteristics (see Appendix E). Given its importance, technology maturity has been examined, recognising that the ratings used in this report represent a point in time, especially given the pace of change across technologies.

Figure 13: Energy storage systems classification

Electrochemical energy storage

Systems that employ chemical reactions to convert and store electricity in chemical form for a period of time, which can then be reversed repeatedly and released back into the system as electricity.

Mechanical energy storage

Systems that use gravity, acceleration or compression to store kinetic energy, which can generate electricity upon release.

Chemical energy storage

Systems in which energy is stored in the bonds of chemical compounds and is released during a chemical reaction such as the combustion of a fuel; the energy released can be used directly as heat or be used to generate electricity.

Thermal energy storage

Systems that convert and/or store an energy input (i.e. heat, electricity or concentrated solar thermal) in the form of thermal energy, which can be used at a later period as direct heat or to generate electricity.

25 Please note, although these classifications are generally well-accepted energy storage categories, they are not definitive. In reality, the boundaries of these taxonomy brackets are blurry, with many of the individual technologies using principles across more than one of these areas.

2.1 Technology maturity

Understanding maturity level is important for tracking technology progression, and for understanding investment risks, barriers and actions to commercial scale up.

Technological progress and commercialisation is not a linear process and despite demand and momentum behind several energy storage technologies, some may suffer from hurdles and uncertainty along their development and demonstration pathways. This makes it difficult for decision makers to understand, plan for and develop technologies that can both meet Australia's near-term (2030) demand for energy storage and be competitive and proven options to meet longer term needs (post 2030). Given the rapid pace of change and constant technology announcements in the media, decision makers also face the challenge of staying up to date with the latest developments and discerning progress between technologies.

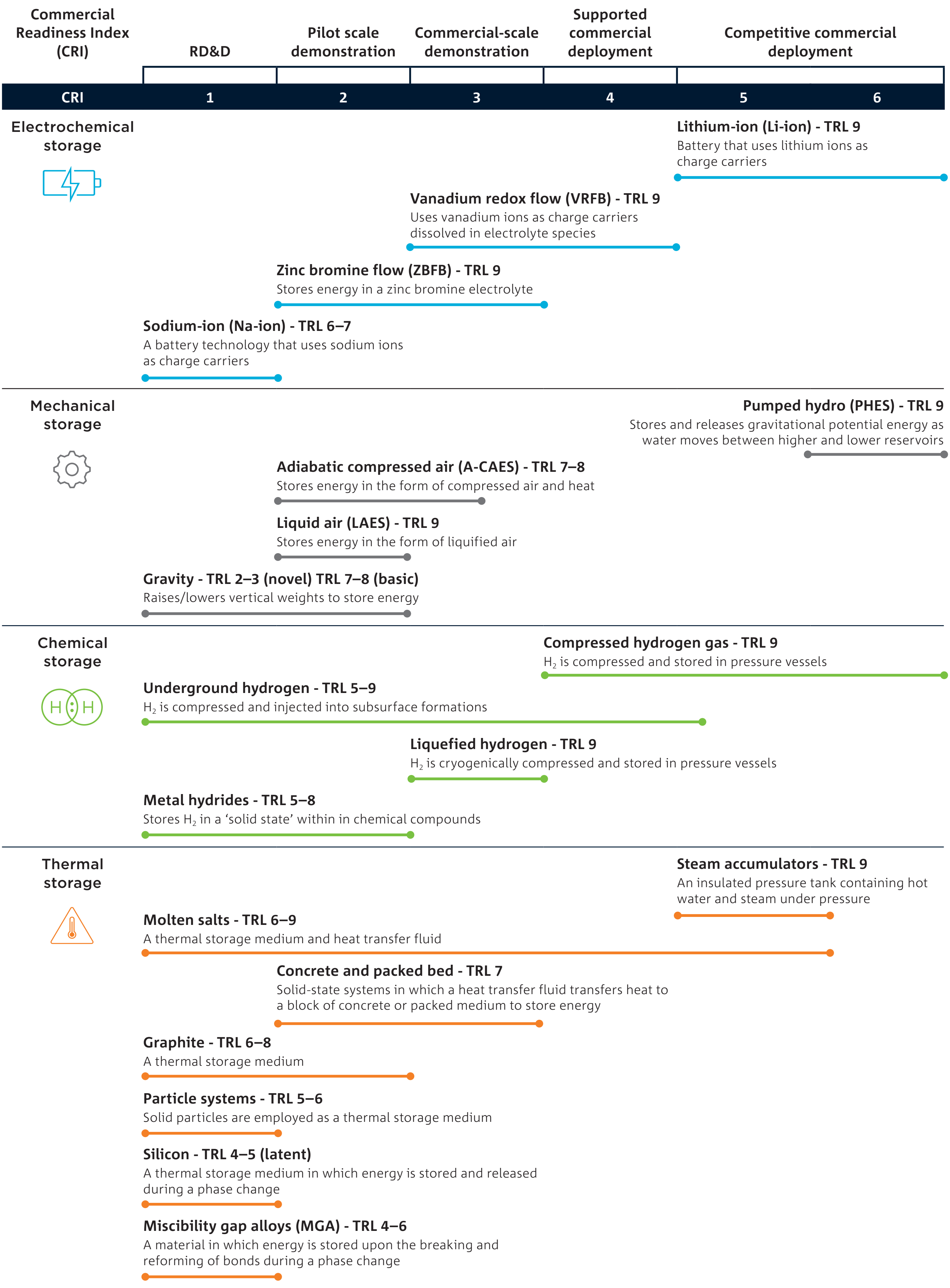
This report uses the CRI and TRL frameworks to examine the maturity levels of energy storage technologies, and as a tool to support decision making (for CRI and TRL definitions, see Energy storage terminology in the Introduction of the report, Table 2). CRI covers technologies that are entering pilot-scale demonstration through to technologies that are commercially competitive to deploy in an international context.

This roadmap assesses CRI based on global technology development because technologies that have matured overseas can be adopted in Australia, reducing duplication of effort and investment. Different TRL/CRI may be assigned for one technology depending on the maturity of integration and the demonstrated commercial use for different end-use applications.

Although these benchmarking tools are useful for gaining a broad understanding of where different energy storage technologies sit in the pathway to commercialisation, these tools do not exist without limitations. This roadmap presents a point-in-time assessment as CRI and TRL ratings will evolve. Moreover, the progression along CRI and TRL scales is not always linear and, despite apparent momentum behind certain systems, some technologies may suffer from hurdles and uncertainty along the development and demonstration pipelines.

Despite the limitations, CRI and TRL can help gauge where a technology lies along its development pathway and be used to understand upcoming milestones that need to be achieved to sustain progress. This could be a technical milestone, related to costs, or could be market related, such as the need for skills and or further development of domestic supply chains.

Figure 14: Summary of energy storage technology maturity



Notes: This diagram illustrates the technological readiness level (TRL)/commercial readiness index (CRI) reached for the end-use applications discussed in this roadmap and as of December 2022. For several technologies, TRL/CRI may differ based on the maturity of integration into emerging end uses. Terminology: RD&D, research, development and demonstration.

2.2 Technology options

Electrochemical storage

Electrochemical storage refers to systems that use chemical reactions to convert and store electricity in chemical form for a period of time that can then be reversed to release electricity back into the system.

The electrochemical energy storage technologies included in this roadmap are Li-ion batteries, sodium ion (Na-ion) batteries, vanadium redox flow batteries (VRFB) and zinc–bromine batteries (ZNBR).

Lithium ion batteries

Li-ion batteries are a form of rechargeable battery that transfers ions between a cathode (positive electrode) and anode (negative electrode) to store and release electricity. Upon battery discharge, positive lithium ions flow from the anode to cathode through the electrolyte, while electrons travel around the external circuit to balance the charge, generating an electric current.

The Li-ion batteries referred to in this roadmap have reached competitive commercial deployment overall, sitting at TRL 9/CRI 4–6 with approximately 16-GW global battery storage capacity installed by the end of 2021.[26] Short-duration, grid-scale storage applications are mature (TRL 9/CRI 5–6).[27] However, medium-duration grid-scale storage applications (>4 hours) are in the supported commercial deployment stage (TRL 9/CRI 4).[28]

Flow batteries (VRFB and ZNBR)

Flow batteries store energy in electroactive species dissolved in liquid electrolytes, which are held in two external storage tanks.[29] These electrolytes are filtered through electrochemical cells, which convert the chemical energy into electricity.

Overall, flow batteries are undergoing commercial-scale demonstrations TRL 9 and CRI 2–4. VRFB have reached supported commercial deployments (TRL 9/CRI 3–4) given the scale of multiple systems, such as the 100-MW/400-MWh grid-connected VRFB at Dalian Rongke Power station in China.[30] However, ZNBR batteries are slightly less mature, sitting at the pilot-scale demonstration stage (TRL 9/CRI 2) after a 2-MWh system was completed in California, USA, in 2022.[31]

26 Schoenfisch M, Dasgupta A (2022) Grid-scale storage: Tracking report. IEA. <https://www.iea.org/reports/grid-scale-storage> (accessed 16 November 2022).

27 Chemistries in scope for the roadmap include lithium metal polymer, lithium nickel manganese cobalt oxide and lithium iron phosphate batteries. There are other Li-ion chemistries at earlier stages of RD&D, such as Li-air and Li-sulphur batteries, but they are not in scope for this discussion; Godfrey B, Dowling R, Forsyth M, Grafton R, Wyld I (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne; Dorfler S, Walus S, Locke J, Fotouhi A, Auger D, Shateri N, Abendroth T, Hartel P, Althues H, Kaskel S (2020) Recent progress and emerging application areas for lithium–sulfur battery technology. Energy Technology 9, 2000694.

28 For example, the 112-MW/560-MWh battery providing 5 hours of storage developed by Fluence in Chile: Fluence (2020) Energy storage's next evolution is unfolding in Chile. <https://blog.fluenceenergy.com/energy-storage-next-evolution-in-chile-andes-solar> (accessed 22 November 2022).

29 Cavanagh K, Ward JK, Behrens S, Bhatt AI, Ratnam EL, Oliver E, Hayward J (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

30 CNESA (2022) After 6 years, the 100MW/400MWh redox flow battery storage project in Dalian is connected to the grid. <http://en.cnesa.org/new-blog/2022/7/19/after-6-years-the-100mw400mwh-redox-flow-battery-storage-project-in-dalian-is-connected-to-the-grid> (accessed 17 November 2011).

31 Redflow (2021) Redflow completes 2 MWh installation in California. <https://redflow.com/project/redflow-completes-2-mwh-installation-in-california> (accessed 17 November 2022).

Sodium ion batteries

Na-ion batteries operate on the same working principle as Li-ion batteries, whereby ions move between the positive and negative electrodes, while electrons travel around an external circuit to balance the charge, generating electricity in the process.

Na-ion batteries are undergoing RD&D at TRL 6–7 and CRI 1.[32] The Smart Sodium Storage System (S4) project led by the University of Wollongong is currently underway in Australia, with the aim of developing and demonstrating novel Na-ion battery technologies in renewable energy storage applications. Internationally, Na-ion batteries are at their nascency, but several manufacturers have released early commercial battery products and plan to develop supply chains and mass production in coming years targeting applications such as transport electrification and stationary storage for residential, industrial and remote areas.[33]

Mechanical storage

Mechanical storage refers to systems that use gravity, acceleration or compression to store kinetic energy, which can generate electricity upon release.

The mechanical energy storage technologies considered in this roadmap are PHES, compressed air, liquid air and gravity storage.

Pumped hydro energy storage

PHES (also referred to as simply 'pumped hydro') uses two vertically separated reservoirs to store gravitational potential energy. Energy is stored by pumping water from a lower reservoir to an elevated reservoir during off-peak periods, before releasing the water back into the lower reservoir, driving a turbine in the process to generate electricity when needed.[34]

Internationally, PHES is a commercially competitive technology deployed extensively across the world (TRL 9/CRI 4–6).[35] Medium- and long-duration large-scale grid-connected systems are commercially competitive (TRL 9/CRI 6), whereas small-scale systems are undergoing supported commercial deployments (TRL 9/CRI 4).

There are multiple sites across Australia; for example, Snowy 2.0 in New South Wales (NSW) is the largest committed renewable energy project in Australia and is expected to provide up to 2,000 MW, or more than 1 week of continuous generation capacity, by 2026.[36] The Queensland Government is investigating a 2-GW PHES facility at Borumba Dam.[37] However, smaller-scale systems are still at the supported commercial deployment stage (CRI 4).[38]

32 Goikolea E, Palomares V, Wang S, Larramendi I, Guo X, Wang G, Rojo T (2020) Na-ion batteries – approaching old and new challenges. Advanced Energy Materials 10, 2002055.

33 CATL (2021) CATL unveils it's latest breakthrough technology by releasing its first generation of sodium-ion batteries. <https://www.catl.com/en/news/665.html> (accessed 16 November 2022); Clarios (2022) Natron collaborates with Clarios on world's first mass manufacturing of sodium-ion batteries. <https://www.clarios.com/news-views/news-detail/2022/05/04/natron-collaborates-with-clarios-on-world-s-first-mass-manufacturing-of-sodium-ion-batteries> (accessed 16 November 2022); Reliance Industries Limited (2021) Reliance New Energy Solar to acquire Faradion Limited. [Media release] <https://www.ril.com/getattachment/12f4988d-7b28-4a68-8900-cfe33c25e5f8/Reliance-New-Energy-Solar-to-Acquire-Faradion-Limi.aspx> (accessed 16 November 2022).

34 AECOM (2015) Energy storage study: Funding and knowledge sharing priorities. <https://arena.gov.au/assets/2015/07/AECOM-Energy-Storage-Study.pdf> (accessed 20 October 2002).

35 Internal source; Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

36 One-week capacity is estimated to power three million homes: Snowyhydro (2018) Project Update: Snowy 2.0 Pumped hydro project. <https://www.snowyhydro.com.au/wp-content/uploads/2018/12/Snowy-2-Project-Update_DECEMBER_2018_web.pdf> (accessed 20 October 2002).

37 Department of Energy and Public Works (2022) Borumba Dam pumped hydro. <https://www.epw.qld.gov.au/about/initiatives/borumba-dam-pumped-hydro> (accessed 20 October 2002).

38 Western Power (2022) Works commence for WA's first pumped-hydro solution < https://www.westernpower.com.au/community/news-opinion/works-commence-for-wa-s-first-pumped-hydro-solution/> (accessed 17 November 2022); Western Power (2022) What is mini-pumped hydro? <https://www.westernpower.com.au/our-energy-evolution/grid-technology/what-is-mini-pumped-hydro/> (accessed 17 November 2022)..

Compressed air

There are several permutations of compressed air energy storage (CAES) systems, but only adiabatic compressed air energy storage (A-CAES) systems are considered in this report.[39]

At a basic level, ambient air is compressed and stored under pressure in an underground cavern. When electricity is required, the pressurised air is released, causing it to expand and drive a generator that then produces power.

A-CAES systems are currently at the commercial-scale demonstration stage (TRL 9/CRI 2–3). A commercially contracted Hydrostor facility is operational at 1.75 MW (discharge) and 10 MWh in Ontario, Canada, and two larger-scale projects are planned to commence construction in California, USA (500 MW), and in NSW (200 MW).[40]

Liquid air

Liquid air energy storage (LAES) operates on the principle that air can be liquefied at low temperatures and ambient pressure, greatly reducing its volume by approximately 700-fold. Off-peak energy is used to liquefy air at –196°C in unpressurised vessels. When needed, the air is heated, causing it to expand and drive a turbine, which generates electricity.[41]

These systems are in the pilot-scale demonstration phase (TRL 9/CRI 2), given Highview Power has completed a 5-MW/15-MWh pilot plant and commenced construction of a 50-MW/250-MWh LAES system in the UK.[42] Highview Power also plans to construct a 50-MW/500-MWh LAES plant in Chile.[43]

Gravity

In its basic form, gravity energy storage involves mechanically raising weights during the charging phase, which are then released during the discharging phase to drive a generator to produce electricity. Although this describes gravity storage with vertical weight systems, it is worth noting that rail and mountain gravity systems also exist, even though they are not discussed in this roadmap.[44]

Permutations of vertical gravity systems exist and include dry above-ground (using cranes) or underground systems (using deep caverns, such as abandoned mine shafts), as well as wet underground systems that operate under a principle similar to PHES.

Some pilot and commercial-scale demonstrations are being deployed in grid applications, industrial parks and mining applications (TRL 7–8/CRI 1-2).[45] More novel designs are less developed (TRL 2–3/CRI 1).[46]

39 Diabatic CAES systems are the most mature and commercially available, but are not considered low emission due to their use of gas turbines; as such, they are not considered in this roadmap. Isothermal CAES systems are low TRL, and so are also not considered in this roadmap.

40 Hydrostor (2022) Our projects. <https://www.hydrostor.ca/projects/> (accessed 20 October 2022); Bowen T, Chernyakhovskiy I, Xu K, Gadzanku S, Coney K (2021) USAID grid-scale energy storage technologies primer. National Renewable Energy Laboratory. <https://www.nrel.gov/docs/fy21osti/76097.pdf> (accessed 20 October 2022).

41 Borri E, Tafone A, Romagnoli A, Comodi G (2021) A review on liquid air energy storage: History, state of the art and recent developments. Renewable and Sustainable Energy Reviews 137, 110572.

42 Highview Power (2020) Highview Power Breaks Ground on 250MWh CRYOBattery Long Duration Energy Storage Facility < https://highviewpower.com/news_announcement/highview-power-breaks-ground-on-250mwh-cryobattery-long-duration-energy-storage-facility/> (accessed 24 November 2022); Highview (2018) Highview Power launches world's first grid-scale liquid air energy storage plant. <https://highviewpower.com/news_announcement/world-first-liquid-air-energy-storage-plant/> (accessed 12 October 2022).

43 Enlasa (2022) About us. < https://www.enlasa.com/sobre-nosotros/> (accessed 24 November 2022); Enlasa (2022) Energy Storage < https://www.enlasa.com/almacenamiento-larga-duracion/> (accessed 24 November 2022).

44 Botha A, Kamper M, Wang R (2021) Design optimisation and cost analysis of linear Vernier electric machine-based gravity energy storage systems. Journal of Energy Storage 44, 103397.

45 Enel (2021) Wind power and energy storage converge in the name of circular innovation https://www.enelgreenpower.com/media/news/2021/07/innovation-wind-energy-storage (accessed 24 November 2022); Businesswire (2022) 2-Gigawatt Hour (2 GWh) Mandate Announced for Energy Vault's EVxTM Gravity Energy Storage Platform for Initial Zero Carbon Industrial Parks in China < https://www.businesswire.com/news/home/20220915005772/en/2-Gigawatt-Hour-2-GWh-Mandate-Announced-for-Energy-Vault%E2%80%99s-EVx%E2%84%A2-Gravity-Energy-Storage-Platform-for-Initial-Zero-Carbon-Industrial-Parks-in-China> (accessed 24 November 2022); Paul S (2022) Korea Zinc backs storage developer Energy Vault in green push. Australian Financial Review. <https://www.afr.com/policy/energy-and-climate/korea-zinc-backs-storage-developer-energy-vault-in-green-push-20220105-p59m42> (accessed 22 November 2022).

46 Internal Source.; Energy Vault (2021) EV1 commercial demonstration unit. <https://www.energyvault.com/cdu> (accessed 24 October 2022).

Chemical storage

Chemical storage refers to systems in which energy is stored in the bonds of chemical compounds and released during a chemical reaction, such as the combustion of a fuel.

To manage scope and given Australia's ambitions in the hydrogen industry, the chemical energy storage technologies considered in this roadmap have been focused on hydrogen storage technologies, including hydrogen gas tanks, liquefied hydrogen, hydrogen pipelines, underground hydrogen and metal hydrides. Where relevant, other chemical storage systems that have not been explored in this report are mentioned as part of the technology options discussion for individual sectors in Part III. This includes various hydrogen derivatives and biofuels and biogas.

Compressed hydrogen tanks

There are three storage applications considered for the use of compressed hydrogen gas tanks, and these are represented at maturity as TRL 9/CRI 2–6:

- Grid-connected storage, which involves the use of hydrogen gas tank storage for direct conversion to electricity for power applications, has completed pilot-scale demonstrations (CRI 2).[47] Commercial-scale demonstration projects for grid use include the Port Lincoln Hydrogen Energy Storage System commissioned in South Australia in 2021. Once constructed, the system will provide grid support services to the NEM, as well as backup power to a nearby microgrid.[48]
- Storage of hydrogen at industrial sites along the export supply chain (e.g. use as a feedstock for ammonia production), which has been commercial for many decades and is at CRI 5–6.[49]
- Integration of hydrogen gas tanks at hydrogen refuelling stations (HRS), which has reached supported commercial deployment (CRI 4). Over 900 HRS and commercial-scale demonstrations have been undertaken worldwide. These deployments are focussed on improving the costs of high-pressure compression and refuelling speeds for heavy vehicles.[50]

Liquefied hydrogen

Liquefied hydrogen involves compressing, cooling and storing hydrogen at –253°C in cryogenic tanks. Although liquefied hydrogen is mature for specialised applications like rocket fuel, bulk storage of liquefied hydrogen is at TRL 9/CRI 3 for export scales. Commercial and demonstration projects include the Hydrogen Energy Supply Chain Project from Australia to Japan, which was the world's first commercial-scale demonstration of liquefied hydrogen export.[51] Liquefied hydrogen at volumes of up to 100,000 m^3 is being developed internationally.[52] In the transport sector, cryogenic hydrogen for refuelling heavy-duty hydrogen vehicles is under investigation due to its potential to speed up refuelling times.[53]

47 Government of South Australia (2017) South Australian green hydrogen study. Government of South Australia, Adelaide; Parkinson G (2018) S.A. to host Australia's first green hydrogen power plant. <https://reneweconomy.com.au/s-a-to-host-australias-first-green-hydrogen-power-plant-89447/> (accessed 14 October 2022).

48 Harmsen (2018) Hydrogen-fuelled power plant planned at Port Lincoln. ABC News. <https://www.abc.net.au/news/2018-02-12/hydrogen-power-plant-port-lincoln/9422022> (accessed 26 October 2022).

49 Hydrogen gas stored at lower pressures of 100–300 bar has been used for industrial purposes for many years, sitting at TRL 9/CRI 6: Barthélémy H (2012) Hydrogen storage – industrial prospectives. International Journal of Hydrogen Energy 37, 17364–17372.

50 IEA (2022) Global hydrogen review 2022. <https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf> (accessed 20 October 2022).

51 HESC (2022) About the project. <https://www.hydrogenenergysupplychain.com/about-hesc/> (accessed 24 October 2022); HESC (2022) Report: Successful completion of the HESC pilot project. <https://www.hydrogenenergysupplychain.com/report-successful-completion-of-the-hesc-pilot-project/> (accessed 24 October 2022); HESC (n.d.) Liquefied hydrogen carrier. <https://www.hydrogenenergysupplychain.com/supply-chain/the-suiso-frontier/> (accessed 24 October 2022).

52 Shell, NASA, CB&I and the University of Houston are undertaking a project to develop liquefied hydrogen tanks with target volumes between 20,000 and 100,000 m3: Stetson N (2021) Importance of liquid hydrogen for decarbonizing the energy sector. U.S. Department of Energy. <https://www.energy.gov/sites/default/files/2021-10/doe-perspectives-lh2.pdf> (accessed 24 October 2022).

53 Burke A, Fulton L (2022) Use of liquid hydrogen in heavy-duty vehicle applications: Station and vehicle technology and cost considerations. <https://escholarship.org/content/qt22z8260f/qt22z8260f_noSplash_471a1fd55d7f6bc82febb5e5897f7b4c.pdf> (accessed 22 October 2022); TüV Nord (n.d.) Hydrogen storage: Overview of possibilities. <https://www.tuev-nord.de/en/company/energy/hydrogen/hydrogen-storage/> (accessed 22 October 2022); H_2 Mobility. Overview: Hydrogen refuelling for heavy duty vehicles. <https://h2-mobility.de/wp-content/uploads/sites/2/2021/08/H2-MOBILITY_Overview-Hydrogen-Refuelling-For-Heavy-Duty-Vehicles_2021-08-10.pdf> (accessed 22 October 2022).

Underground hydrogen

Underground hydrogen technology involves compressing and injecting hydrogen gas into subsurface formations via wells. There are four main geological options for underground hydrogen: salt caverns, depleted oil and gas reservoirs, aquifers and hard rock caverns.[54]

Overall, the maturity of underground hydrogen storage is in the range TRL 5–9/CRI 1–4. This range illustrates different maturity levels for various geologies, and that underground storage is only commercially used in the context of industrial chemical and refinery industries (e.g. in salt caverns across the US and UK). More recent international demonstrations indicate that this maturity differs by end-use application. Salt cavern systems for grid-connected storage applications are undergoing pilot-scale demonstrations (TRL 8–9/CRI 2). There are currently no large-scale underground hydrogen projects operating for the purposes of providing storage for electricity grids; however, a few are scheduled to be demonstrated internationally, such as the US Advanced Clean Energy Project.[55] Depleted hydrocarbon reservoirs, aquifers and engineered caverns are undergoing pilot-scale demonstrations (TRL 5–7/CRI 1).[56]

Metal hydrides

Metal hydrides are chemical compounds in which hydrogen bonds to metal atoms. Hydrogen is stored in solid state under mild conditions and is released by adding heat to the system.

Metal hydrides are undergoing pilot-scale demonstrations, sitting at TRL 8–9/CRI 2. There are several projects underway; LAVO completed a metal hydride demonstration at a Coregas facility in Adelaide and GHD has recently secured funding from the UK Government to install a demonstration plant featuring LAVO's hydrogen-based battery technology in England.[57]

Hydrogen pipelines

Line packing is a widely used storage method in Australia's gas networks whereby natural gas is stored within the pipeline network. This method can also be used to store renewable gas such as hydrogen. The volume of hydrogen (or other gases) stored in a pipeline can be increased by increasing the pressure of the gas contained within the pipeline, and additional storage capacity can be added by increasing the diameter of the pipeline.

Hydrogen can be transported via a dedicated hydrogen pipeline (100% hydrogen) or injected into existing natural gas networks at lower concentrations. The extent to which hydrogen can be blended depends on the pipeline's material and its resistance to hydrogen embrittlement.

54 Lord A, Kobos P, Borns D (2014) Geologic storage of hydrogen: Scaling up to meet city transportation demands. International Journal of Hydrogen Energy 39, 15570–15582.

55 IEA (2022) Global hydrogen review 2022. <https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf> (accessed 20 October 2022).

56 Ennis-King J, Michael K, Strand J, Sander R, Green C (2021) Underground storage of hydrogen: Mapping out the options for Australia. Future Fuels CRC. <https://www.futurefuelscrc.com/wp-content/uploads/FutureFuelsCRC_UndergroundHydrogenStorage2021.pdf> (accessed 22 October 2022); IEA (2022) Global hydrogen review 2022. <https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf> (accessed 20 October 2022).

57 Carroll D (2022) Australian hydrogen battery technology to be tested in UK. <https://www.pv-magazine.com/2022/02/24/australian-hydrogen-battery-technology-to-be-tested-in-uk/> (accessed 22 November 2022); Coregas (2021) LAVO completes demonstration installation at Coregas. <https://www.coregas.com.au/news/2021/lavo-completes-demonstration-installation-at-coregas> (accessed 22 November 2022).

58 Wang H, Tong Z, Zhou G, Zhang, C, Zhou H, Wang Y, Zheng W (2022) Research and demonstration on hydrogen compatibility of pipelines: A review of current status and challenges. International Journal of Hydrogen Energy 47, 28585–28604.

Pure hydrogen pipelines have been commercially demonstrated and are at TRL 8–9/CRI 2–3. Air Products operates a pure hydrogen pipeline over 2,500 km in the US to supply the chemical and refinery sectors, and the European Hydrogen pipeline is over 1,600 km, partially operated by Air Liquide.[58] In Australia, APA Group plans to convert the Parmelia Gas Pipeline in WA to a 100% hydrogen pipeline capable of transporting pure or blended hydrogen.[59]

Blended hydrogen in gas networks has been demonstrated internationally and in Australia. Blends of up to 20% hydrogen have been demonstrated in the UK, Europe and the US, in controlled environments, with the aim being to commence injecting hydrogen into gas networks within the next year.[60] A demonstration was completed in South Australia for blends of up to 5% hydrogen,[61] and a study has confirmed that the Dampier Bunbury Pipeline can support up to 9% hydrogen blending.[62]

Thermal storage

Thermal storage refers to systems that convert and/or store an energy input (i.e. heat, electricity or concentrated solar thermal) in the form of thermal energy, which can be used at a later period as direct heat or to generate electricity.

The thermal energy storage systems considered in this roadmap are steam accumulators, the storage component of concentrated solar thermal (CST)[63], and eTESe/eTESh systems (thermal energy storage with electricity input and either electricity output [eTESe] or heat output [eTESh]). The thermal storage media considered for use in thermal systems include molten salts, graphite blocks, miscibility gap alloys (MGA), silicon, particle systems, concrete storage and packed bed systems. Unlike some of the other storage processes, thermal storage technologies can generally be 'charged' using renewable generated heat (i.e., CST), electricity, and waste process heat, and can provide a thermal energy output or an electrical energy output if paired with equipment such as a boiler or turbine. To manage scope, this report has not explored water tank thermal energy storage or the use of cold (low-temperature and <0°C) thermal energy storage. Both water tanks and cold thermal energy storage have a broad range of existing applications in buildings and refrigeration, such as in vehicles and static chillers.[64]

59 apa (2021) apa set to unlock Australia's first hydrogen ready transmission pipeline. <https://www.apa.com.au/news/media-statements/2021/apa-set-to-unlock-australias-first-hydrogen-ready-transmission-pipeline/> (accessed 24 October 2022).

60 Energy Networks Association (2022) #H2Explainer: Where next for hydrogen blending? <https://www.energynetworks.org/newsroom/h2explainer-what-next-for-hydrogen-blending> (accessed 24 October 2022); DVGW (2021) Avacon and DVGW, together with Economics Minister Sven Schulze, put a hydrogen admixing plant into operation. [In German] <https://www.dvgw.de/der-dvgw/aktuelles/presse/presseinformationen/dvgw-presseinformation-vom-17122021-wasserstoff-beimischung-avacon-dvgw> (accessed 24 October 2022); Hydrogen Central (2021) SoCalGas among first in the nation to test hydrogen blending in real-world infrastructure and appliances in closed loop system. <https://hydrogen-central.com/socalgas-test-hydrogen-blending-infrastructure/> (accessed 24 October 2022).

61 Australian Gas Networks (n.d.) Hydrogen park South Australia. <https://www.australiangasnetworks.com.au/hyp-sa> (accessed 24 October 2022).

62 Matich B (2022) Studies show Dampier Bunbury pipeline capable of 9% hydrogen blending, but underground storage less promising. <https://www.pv-magazine-australia.com/2022/01/20/studies-show-dampier-bunbury-pipeline-capable-of-9-hydrogen-blending-but-underground-storage-less-promising/> (accessed 24 October 2022).

63 CST systems comprise both generation and storage components, and as such the roadmap focuses on the thermal storage component of CST systems.

64 International Renewable Energy Agency (IRENA) (2020) Innovation outlook: Thermal energy storage. IRENA, Abu Dhabi.

Steam accumulators[65]

Steam accumulators are typically steel pressure tanks designed to store pressurised hot water, which is discharged, when required, as lower pressure saturated steam. The tanks can be 'charged' with other process steam as an input.

Steam accumulators are generally capable of providing saturated steam at temperatures up to 300°C in commercial applications,[66] after which point the commercial feasibility decreases due to increased vessel manufacturing requirements. [67] Pressure vessels provide short-term storage (up to 1–2 hours), primarily used to bridge gaps in intermittent steam generation and for industrial process heat applications.[68] However, there is no technical constraint limiting steam accumulators from providing up to 10 hours of storage.[69]

Steam accumulators are at TRL 9/CRI 5, given commercial deployments exist for process heat at some industrial sites, and there are widespread suppliers and engineering contractors that can provide the technology.[70]

Concentrated solar thermal

CST systems use an array of mirrors to concentrate sunlight onto a target to heat a thermal medium to very high temperatures. This heat can then be used directly for industrial process heat, or be used to generate electricity, usually by heating water to run a turbine. Several CST designs exist: tower systems, where solar heat is targeted towards a central receiver atop a tower; parabolic trough systems and linear Fresnel systems, where solar heat is targeted towards a pipe containing heat transfer fluid; and parabolic dish systems, where heat targets a receiver mounted atop the dish structure.[71]

Other types of CST systems include tower systems where the receiver is a specialised solar PV receiver. The sunlight is directly converted to electricity, which can be fed into the grid. These systems also include long-duration energy storage in the form of hot and cold water. By-product heat from the solar PV receiver is stored as hot water, and the electricity is also used to chill cold water. The hot and cold water are then used to run an Organic Rankine Cycle engine to provide power on demand. Although hot and cold water are not included within the scope of thermal storage technologies in this roadmap, the generation capability of this technology has been demonstrated in Australia for grid applications by RayGen, and the storage component is expected to be complete in 2023.[72]

Thermal energy storage systems

Thermal energy storage (electricity input) (eTES) systems use electrical energy to charge a thermal medium, which stores energy in the form of heat. This is subsequently released and either used directly as industrial process heat (eTESh) or used to generate electricity (eTESe). eTES systems can be set up in various configurations (e.g. as standalone systems or integrated into existing plants or infrastructure) and can enable the coupling of electricity, heating and cooling and improve energy efficiency.[73]

65 Lovegrove et al. (2019) Renewable energy options for industrial process heat appendices. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/appendices-renewable-energy-options-for-industrial-process-heat.pdf> (accessed 21 October 2022).

66 Al Kindi et al (2019) Thermodynamic Assessment of Steam-Accumulation Thermal Energy Storage in Concentrating Solar Power Plants. International Conference on Applied Energy 2019, Västerås, Sweden. Available < https://www.researchgate.net/publication/335543160_Thermodynamic_Assessment_of_Steam-Accumulation_Thermal_Energy_Storage_in_Concentrating_Solar_Power_Plants>

67 Lovegrove et al. (2019) Renewable energy options for industrial process heat appendices. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/appendices-renewable-energy-options-for-industrial-process-heat.pdf> (accessed 22 October 2022).

68 Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/appendices-renewable-energy-options-for-industrial-process-heat.pdf> (accessed 21 October 2022).

69 Internal source.

70 Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/renewable-energy-options-for-industrial-process-heat.pdf> (accessed 21 October 2022).

71 SolarPACES (2018) How CSP works: Tower, trough, fresnel or dish. <https://www.solarpaces.org/how-csp-works/> (accessed 22 November 2022).

72 RayGen (2022) Next generation solar and storage. <https://raygen.com/> (accessed 22 November 2022).; ARENA (2021) RayGen solar power plant demonstration. <https://arena.gov.au/projects/raygen-solar-power-plant-demonstration/> (accessed 22 November 2022).; Photon Energy Group (2021) Photon Energy to Develop 300MW / 3.6 GWh RayGen Solar Storage Project in Australia <https://www.photonenergy.com/en/news/photon-energy-to-develop-300-mw-3-6-gwh-raygen-solar-storage-project-in-australia.html?> (accessed 24 November 2022).

73 Siemens Gamesa Renewable Energy (n.d.) Introducing electric thermal energy storage (ETES) – putting gigawatt hours of energy at your command. <https://www.siemensgamesa.com/-/media/siemensgamesa/downloads/en/products-and-services/hybrid-power-and-storage/etes/siemens-gamesa-storage-etes-storage-brochure-en.pdf> (accessed 22 November 2022); MAN Energy Solutions (2022) Maximizing renewable resources with MAN ETES. <https://www.man-es.com/energy-storage/solutions/energy-storage/electro-thermal-energy-storage> (accessed 22 November 2022).

Thermal media

Molten salts[74]

Molten salts are a type of heat transfer fluid and storage medium that stores thermal energy from an electrical or thermal energy source (e.g. a solar collector). Once heated, the salts are sent to a hot storage tank for later use.

Given molten salts have a greater operating temperature range (300–600°C) than other heat transfer fluids, and have high energy density, they can also support a wider variety of power generation applications.[75] Further, the tank storage system allows for multihour storage, typically up to 18 hours in most operational systems.[76]

Molten salts have reached supported commercial deployment; however, the technical and commercial readiness (TRL 6–9/CRI 1–5) of this technology depends on the end-use application and energy input source.[77] The most commercially mature molten salt systems exist for power applications using CST (TRL 9/CRI 4–5). Examples include the commercially operational Crescent Dunes Solar Energy Project in the US and the Gemasolar power plant in Spain.[78] Standalone molten salt systems used for power applications (i.e. eTESe) are less mature (TRL 7–8/CRI 1–2), with concepts under development internationally.[79] For thermal applications (eTESh), molten salt storage is undergoing RD&D (CRI 1).[80]

Graphite

Graphite blocks are a thermal medium that stores thermal energy from an electrical or thermal energy source (e.g. an electric bar heater). The heat is then transferred by conduction from the graphite to a heat exchanger, and used in industrial processes or to generate electricity. Graphite block systems are a modular, scalable and flexible heat storage system that uses abundant and affordable materials, allowing for easy integration into existing systems. Graphite storage systems have an operating temperature generally from 200°C to over 750°C.[81] However, process heat outputs can vary depending on application requirements.[82] Thermophotovoltaic systems can operate with heat outputs up to 1500°C.[83] Graphite systems are used primarily for industrial process heat applications (steam or air). Commercially, the main uptake barriers are around high initial cost and integration risk.

74 Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/knowledge-bank/renewable-energy-options-for-industrial-process-heat/> (accessed 21 October 2022)

75 Some molten salts have even lower temperature limits (down to 140°C), such as HITEC Heat Transfer Salt: Lovegrove et al (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/renewable-energy-options-for-industrial-process-heat.pdf> (accessed 21 October 2022).

76 Average duration of storage worldwide: Bauer T, Odenthal C, Bonk A (2021) Molten salt storage for power generation. Chemie Ingenier Technik 93, 534–546.

77 Power use with CST input (TRL 9/CRI 4–5), standalone power use with electrical input (TRL 7–8/CRI 1–2) and thermal use with CST input (TRL 6/CRI 1). References are provided in Appendix E.

78 U.S. Department of Energy (2013) EERE success story – mirage to reality: Energy Department investment brings Crescent Dunes to life. <https://www.energy.gov/eere/success-stories/articles/eere-success-story-mirage-reality-energy-department-investment-brings> (accessed 12 October 2022); Power Technology (2011) Gemasolar concentrated solar power. <https://www.power-technology.com/projects/gemasolar-concentrated-solar-power/> (accessed 12 October 2022).

79 IRENA (2020) Innovation outlook: Thermal energy storage. IRENA, Abu Dhabi; MAN Energy Solutions (n.d.) MAN MOSAS – shaping the future of renewable energy. <https://www.man-es.com/energy-storage/solutions/energy-storage/mosas> (accessed 12 October 2022).

80 For both eTESh and CST systems used for thermal applications: Italian Agency for Energy Efficiency (n.d.) Use of molten salts as a thermal vector fluid and heat storage system at medium- and high- temperature. <https://www.enea.it/en/ateco/schede/molten-salts-thermal-vector-fluid-and-storage-medium-high-temperature/display_pdf> (accessed 14 October 2022).

81 Guan C, Lu H, Zhang L, Yu Z (2020) Regulation of the output temperature in a novel water heating system using solid graphite as sensible heat thermal energy storage medium: Effects of water tank. Energy Reports 6 (Supplement 7), 160–171; Graphite Energy (2022) Proven, reliable graphite thermal energy storage. <https://www.graphiteenergy.com/technology> (accessed 18 November 2022).

82 For example, the Mars Wodonga demonstration project is designed to deliver 150–200°C process heat output, which is below the system temperature range provided: Graphite Energy (n.d.) Industrial heat decarbonisation. <https://www.graphiteenergy.com/green-heat> (accessed 17 June 2022).

83 Briggs J Antora Energy (2021) Solid state thermal battery. ARPA-E DAYS Annu. Meet., Advanced Research Projects Agency – Energy cited in Novotny V, Basta V, Smola P, Spale J (2022) Review of Carnot battery technology commercial development. Energies 15, 647; Guan et al. (2020) Regulation of the output temperature in a novel water heating system using solid graphite as sensible heat thermal energy storage medium: Effects of water tank. Energy Reports 6 (Supplement 7), 160–171.

The technical and commercial readiness of graphite systems vary depending on the system type used (TRL 6–8/CRI 1–2).[84] Technology proponents in Australia are currently pursuing thermal energy storage applications (eTESe and eTESh), but the technology has potential to be applied to CST in the future. For power applications, Graphite Energy previously developed a CST and thermal energy storage (3.5-MW_e) energy storage plant in Lake Cargelligo, NSW, and is developing a hybrid solar PV and graphite thermal energy storage system referred to as Project Platypus.[85] In manufacturing, commercial deployment of graphite systems in Australia is underway. The Mars Petcare facility in Wodonga, Victoria, will be using a graphite thermal energy storage system to displace onsite natural gas. The system will use grid electricity to store thermal energy at over 500°C, which can then be used to generate high-pressure steam between 150°C and 250°C to manufacture pet food products. Each system unit is capable of storing approximately 3 MWh of thermal energy.[86]

Concrete and packed bed systems[87]

Both concrete and packed bed systems are forms of solid-state thermal energy storage that use sensible heat storage.

In concrete storage systems, concrete blocks are heated by heat transfer fluids in steel pipes running through the concrete. Concrete has the advantage of being a cheaper material than graphite. Temperatures of up to 400°C have been recorded for sensible heat storage in concrete.[88,89]

Packed bed systems are similar to concrete systems, but instead have media such as pebbles or rocks stored in vessels, which are heated with hot air. Packed bed systems also include stationary particle systems. Packed bed systems can operate at temperatures up to 800°C.

Concrete and packed bed systems are used primarily for industrial process heat applications and are currently being demonstrated at commercial scales (CRI 2–3). There has been a focus on concrete and packed bed research and development around the world. In terms of types of packed bed, the largest commercial demonstration is an 8-MWh sand battery in Finland.[90] Further, a crushed rock system has been installed at a facility in Brazil and a volcanic rock system has been installed in Germany.[91] In addition, concrete pilot systems are being trialled in Germany and the US.[92]

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84 For power use (TRL 6–7/CRI 1) and for thermal use (TRL 7–9/CRI 1–2). References are provided in Appendix E.

85 The 3.5-MW_e demonstration project is no longer active: Graphite Energy (n.d.) Project Platypus: Solar TES hybrid plant. <https://www.graphiteenergy.com/platypus-tes-demonstration> (accessed 22 November 2022).

86 Purtill J (2022) A 'graphite battery' in Wodonga will be Australia's first commercial thermal energy storage. triple j Hack. <https://www.abc.net.au/news/2022-08-04/graphite-battery-will-be-first-commercial-thermal-energy-storage/101295350> (accessed 24 October 2022).

87 Lovegrove et al (2019) Renewable energy options for industrial process heat appendices. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/appendices-renewable-energy-options-for-industrial-process-heat.pdf> (accessed 22 October 2022).

88 Zhang H, Baeyens J, Cáceres G, Degrève J, Lv Y (2016) Thermal energy storage: Recent developments and practical aspects. Progress in Energy and Combustion Science 53, 1–40; Knobloch K, Muhammad Y, Soler Costa M, Mayta Moscoso F, Bahl C, Alm O, Engelbrecht K (2022) A partially underground rock bed thermal energy storage with a novel air flow configuration. Applied Energy 315, 118931.

89 Lovegrove et al (2019) Renewable energy options for industrial process heat appendices. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/appendices-renewable-energy-options-for-industrial-process-heat.pdf> (accessed 22 October 2022).

90 Polar Night Energy (2022) The first commercial sand-based thermal energy storage in the world is in operation – BBC News visited polar night energy. <https://polarnightenergy.fi/news/2022/7/5/the-first-commercial-sand-based-thermal-energy-storage-in-the-world-is-in-operation-bbc-news-visited-polar-night-energy> (accessed 22 November 2022).

91 Walton R (2022) Biomass-fueled thermal energy storage creating heat for plastic manufacturing plant in Brazil. EnergyTech. <https://www.energytech.com/energy-storage/article/21249082/biomassfueled-thermal-energy-storage-creating-heat-for-plastic-manufacturing-plant-in-brazil> (accessed 24 October 2022); Siemens Gamesa (n.d.) Energy storage on the rise. <https://www.siemensgamesa.com/explore/innovations/energy-storage-on-the-rise> (accessed 24 October 2022).

92 Hume S (2021) Concrete thermal energy storage enabling flexible operation without coal plant cycling. Electric Power Research Institute. <https://netl.doe.gov/sites/default/files/netl-file/21TPG_Hume_0.pdf> (accessed 24 October 2022); Hoivik N, Greiner C, Barragan J, Iniesta AC, Skeie G, Bergan P, Blanco-Rodrigues P, Calvet N (2019) Long-term performance results of concrete-based modular thermal energy storage system. Journal of Energy Storage 24, 100735; National Energy Technology Laboratory (NETL) (2020) NETL explores concrete solutions to store thermal energy. <https://netl.doe.gov/node/9624> (accessed 20 October 2022).

Concrete and packed beds can also be used as CST thermal storage media; while they have a lower energy density than molten salts, they can achieve a wider working temperature range, benefit from being low-cost and are easily supplied.[93] Demonstrations include the 4-MW Airlight Energy CST plant in Morocco, which uses a packed bed of rocks.[94]

Particle systems

Particle systems (also known as moving particle systems) involve a falling curtain of particles that are heated with concentrated sunlight. Typically, particle systems target a temperature of 800–1,000°C depending on the system and material used; however, some proponents are targeting temperatures of up to 1,500°C.[95] The thermal energy stored in the particles can then be discharged as heat for high-temperature processes or manufacturing processes, or it can be used to generate electricity. Particle systems are typically deployed within CST systems; however, further R&D is required to determine whether they can operate with eTES systems due to challenges with heating particles using electricity. Particle systems are at TRL 5–6/CRI 1 and are still undergoing RD&D.

CSIRO and the Australian Solar Thermal Research Institute (ASTRI) have built a pilot-scale facility in Newcastle, NSW, and the US Department of Energy has announced a megawatt-scale facility that will be designed to store over 6 hours of storage at temperatures above 700°C.[96]

Silicon

Silicon thermal energy storage systems involve the heating of silicon, which stores thermal energy that can later be released in the form of heat or power. In sensible heat designs, the system operates at temperatures below the melting point of silicon (i.e. below 1,414°C). In latent heat designs (temperatures of 1,414°C and above), thermal energy is stored in silicon, which undergoes a phase change to molten silicon. Upon melting, heat is transferred to the silicon and is stored at a constant temperature; the heat is released as the silicon solidifies upon cooling.

Silicon systems generally target higher temperature applications (above 400°C) and are primarily used for high-temperature industrial process heat applications or power generation. Technology proponents in Australia are targeting the power market, which has a lower target temperature, but commercialisation plans include targeting industries with high-temperature process heat requirements. Typically, silicon systems are designed to provide storage durations of around 8 hours; however, much longer durations may be possible.[97]

93 Kraemer S (2019) Novel CSP design combines the solar receiver with thermal energy storage. Solar PACES, IEA Energy Technology Network. <https://www.solarpaces.org/novel-csp-design-combines-the-solar-receiver-with-thermal-energy-storage/> (accessed 22 November 2022); Martins M, Villalobos U, Delclos T, Armstrong P, Bergan PG, Calvet N (2015) New concentrating solar power facility for testing high temperature concrete thermal energy storage. Energy Procedia 75, 2144–2149.

94 Zavattoni SA, Zanganeh G, Pedretti A, Barbato MC (2018) Numerical analysis of the backed bed TES system integrated into the first parabolic trough CSP pilot-pant using air as heat transfer fluid. AIO Conference Proceedings 2033, 090027.

95 Heliogen (2019) Press release: Heliogen achieves breakthrough temperatures from concentrated sunlight for industrial processes. <https://heliogen.com/press-release-heliogen-achieves-breakthrough-temperatures-from-concentrated-sunlight-for-industrial-processes-with-momentum-toward-commercial-hydrogen-fuel-creation> (accessed 22 November 2022).

96 CSIRO (2021) CSIRO plays part in US next-gen solar thermal technology. <https://www.csiro.au/en/news/news-releases/2021/csiro-plays-part-in-us-next-gen-solar-thermal-technology> (accessed 24 October 2022); Sandia National Laboratories (2021) Gen 3 particle pilot plant (G3P3) – high-temperature particle system for concentrating solar power (Phases 1 and 2). <https://energy.sandia.gov/wp-content/uploads/2021/11/SAND2021_G3P3_Phases1and2_v7_clean.pdf> (accessed 22 November 2022).

97 Some systems that use silicon as a thermal storage medium can offer thousands of megawatt hours of storage capacity: 1414 Degrees (n.d.) Home. <https://1414degrees.com.au/> (accessed 21 September 2022).

The TRL for silicon systems varies based on system design and the target temperature range. Silicon is not typically deployed for CST systems due to optical inefficiencies. Latent heat eTES systems operating at 1,414°C and above are at TRL 4–5/CRI 1. Silicon thermophotovoltaic systems, potentially capable of temperatures above 2,000°C, are at TRL 4 and are expected to be many years away from reaching an operational system.

Demonstration projects in Australia include the Aurora Energy Project, where 1414 Degrees plan to demonstrate a silicon TESS-GRID system paired with a 400-MW solar farm to supply dispatchable electricity and provide grid-firming services.[98]

Miscibility gap alloys

MGAs are microstructures formed between two metallic or semi-metallic elements; a phase change material that exists as discrete particles, encapsulated within a material with a higher melting point. Modular storage systems as MGA block systems can be stacked and scaled in insulated storage tanks. These blocks can also be manufactured and installed onsite as required. Depending on the targeted phase change temperature, MGA can be used for power or industrial process heat applications and are ideal for applications with a specific temperature requirement (i.e. alumina processing at 280°C or power at 560°C). Although MGAs have a theoretical operating temperature up to 1,414°C,[99] a realistic upper limit for this system is approximately 800°C.

MGA are at TRL 4–6/CRI 1, with no large-scale systems operating in Australia.[100] MGAs have been tested in concentrated solar power (CSP) applications,[101] but eTES systems are more progressed with a pilot project underway for installation and commissioning in 2023.[102] By the end of 2022, MGA Thermal plans to begin manufacturing small modular MGA storage blocks at scale.[103]

98 1414 Degrees (2019) 1414 Degrees acquiring Aurora Project near Port Augusta. <https://1414degrees.com.au/acquiring-aurora-project/> (accessed 22 November 2022).

99 The range is due to differences in melting points between Sn and Si MGA: Post A, Rawson A, Sugo H, Cuskelly D, Copus M, Bradley J, Kisi E (2017) Price estimation for miscibility gap alloy thermal storage systems. Renewable Energy and Environmental Sustainability 2, 32.

100 MGA Thermal (2022) MGA thermal pilot. <https://mgathermal.com/pilot> (accessed 8 November 2022).

101 MGA Thermal (2020) MGA applications – storage for CSP. <https://mgathermal.com/blog/mga-applications-storage-for-csp> (accessed 22 November 2022).

102 MGA Thermal (2020) MGA thermal pilot. <https://mgathermal.com/pilot> (accessed 8 November 2022).

103 Kelly M (2022) Newcastle-based clean energy company MGA Thermal unveils the first stage of its new commercial manufacturing facility in Tomago. Newcastle Herald. <https://www.newcastleherald.com.au/story/7798437/mga-thermal-powers-up-to-meet-global-demand-for-clean-energy-storage/> (accessed 24 October 2022).

Part III: Sectoral energy storage requirements

Although energy storage will be key to supporting higher levels of decarbonisation and renewable energy deployment, many Australian sectors face challenges in integrating renewable storage technologies.

Stakeholders in Australia's power, industry and transport sectors are all considering the role of storage in optimising their evolving energy systems and meeting their ongoing requirements for electricity, fuels and/or heat. However, as discussed earlier, the role of storage and the decision to invest is complex and highly dependent on end use and site- and region-specific factors (see Part II).

To better understand the complexities that exist and identify key storage gaps and uncertainties, this section explores seven representative end-use sectors. These sectors were selected due to their economic importance, carbon emission levels, decarbonisation challenges and their representation of various types of energy and storage needs. Given the breadth of technology options and processes, each sector is used provide a deeper analysis for specific applications and storage technologies.

The sector analysis examines the deployment considerations involved in technology selection for a given sector application and explores the applicable technology options. Where possible, sector analysis is supported by LCOS analysis and/or a case study to provide insights on costs or storage requirements. The key messages of the sectors analysed are outlined on the following page.

Major grids will require a significant scale of storage of varying durations to manage imbalances in electricity supply and demand as they transition. There are limited commercially mature (bankable) energy storage options in Australia that are deployable in the near term, and the most widely deployed systems in Australia, lithium-ion batteries and pumped hydro, face supply chain risks and geographical constraints respectively.

For **remote and off-grid mining** sites, short-duration energy storage within a hybrid generation grid can provide significant emissions reductions in the near term and reduce existing levels of fossil fuel usage. However, eliminating emissions in remote mining will also require long-duration storage technology options. While several options could potentially be commercially competitive with diesel, these are not widely demonstrated at scale across mining operations.

Energy storage paired with renewables has the potential to increase access to electricity supply for **remote communities**, support high levels of decarbonisation and reduce electricity costs. However, the ability to achieve these outcomes across diverse community types and regions will require community engagement. Storage systems will need to be cost-effective in terms of upfront investment and ongoing costs, and easy to maintain. Eliminating emissions will require storage systems capable of maintaining power quality and providing reliable energy for days or weeks.

Thermal and chemical storage systems, as well as process electrification, have the potential to enable the **manufacturing** industry to cost-effectively decarbonise and meet their mid-temperature (150–500°C) heat requirements. However, further demonstration and scale up is required to increase knowledge of decarbonisation pathways and associated storage technology options, as well as to reduce real (or perceived) commercial and technical risks.

The decarbonisation of Australian industries that require high temperature (500°C and above) process heat, such as **alumina calcination**, can have significant implications for storage, with the appropriate solution depending on the chosen decarbonisation pathway. However, industry decisions related to storage will be made in the context of a broader and highly integrated system. Such decisions often bear high up-front costs and are high-risk exercises which can be exacerbated by insufficient information due to a lack of technology maturity and scale.

Large-scale storage will play a critical role in realising **Australia's hydrogen export** industry and could support the development of a domestic hydrogen economy. However, the choice and type of storage required will depend on how a given export value chain is optimised, with implications for maritime and pipeline infrastructure.

Hydrogen storage could play a key role in decarbonising **heavy-duty vehicles**, as fuel cell electric vehicles (FCEVs) are expected to become increasingly competitive for high-load, long-range operations requiring short recharging times. A reliable hydrogen refuelling network will require hydrogen storage at various points along the distribution system. Storage choices will be based on the optimal distribution model to service a given area and should consider opportunities to leverage shared hydrogen assets, such as large-scale hydrogen production and storage at hubs.

3.1 Approach

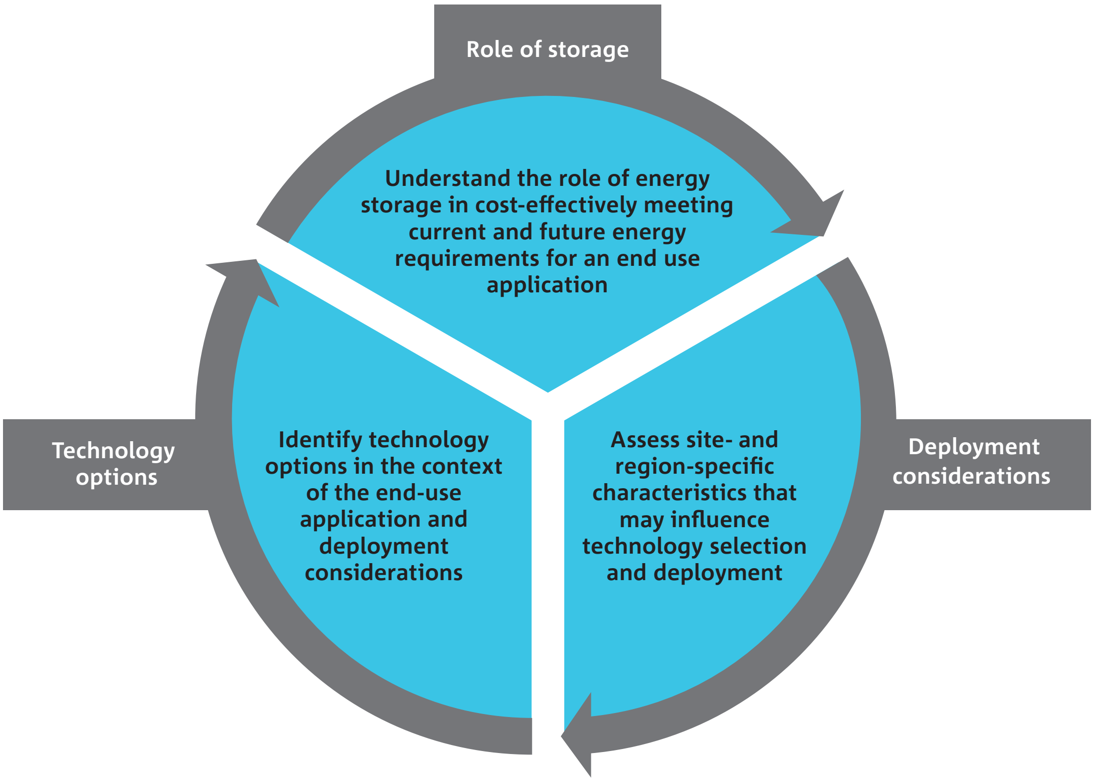
Determining the most competitive and appropriate forms of energy storage requires an understanding of end-use requirements and deployment context.

Australia's energy storage requirements are diverse, and the decision to invest in storage (or to invest in solutions to minimise storage needs) is complex. Rather than picking technology winners, this report combines detailed qualitative and quantitative analysis and stakeholder input to consider energy storage technology options across a selection of end-use applications to allow stakeholders in industry, government and research to make informed choices.

Determining the most competitive and appropriate forms of energy storage requires stakeholders to go through a site- and region-specific process to understand the role of energy storage, the deployment considerations and the technology options available (Figure 15). This process is critical because site and regional factors can affect the costs, risks and integration considerations for a given storage system. They can also affect the applicability or viability of technologies (and their various configurations or subsystems), even among similar sectors and specific end-use applications.

This section provides an overview of the approach to sector analysis applied across Part III. Specifically, this section focuses on deployment considerations, the scope of technology options and the levelised cost of storage (LCOS) methodology, with the role of storage discussed in the context of specific end-use applications.

Figure 15: Energy storage analysis process by end use

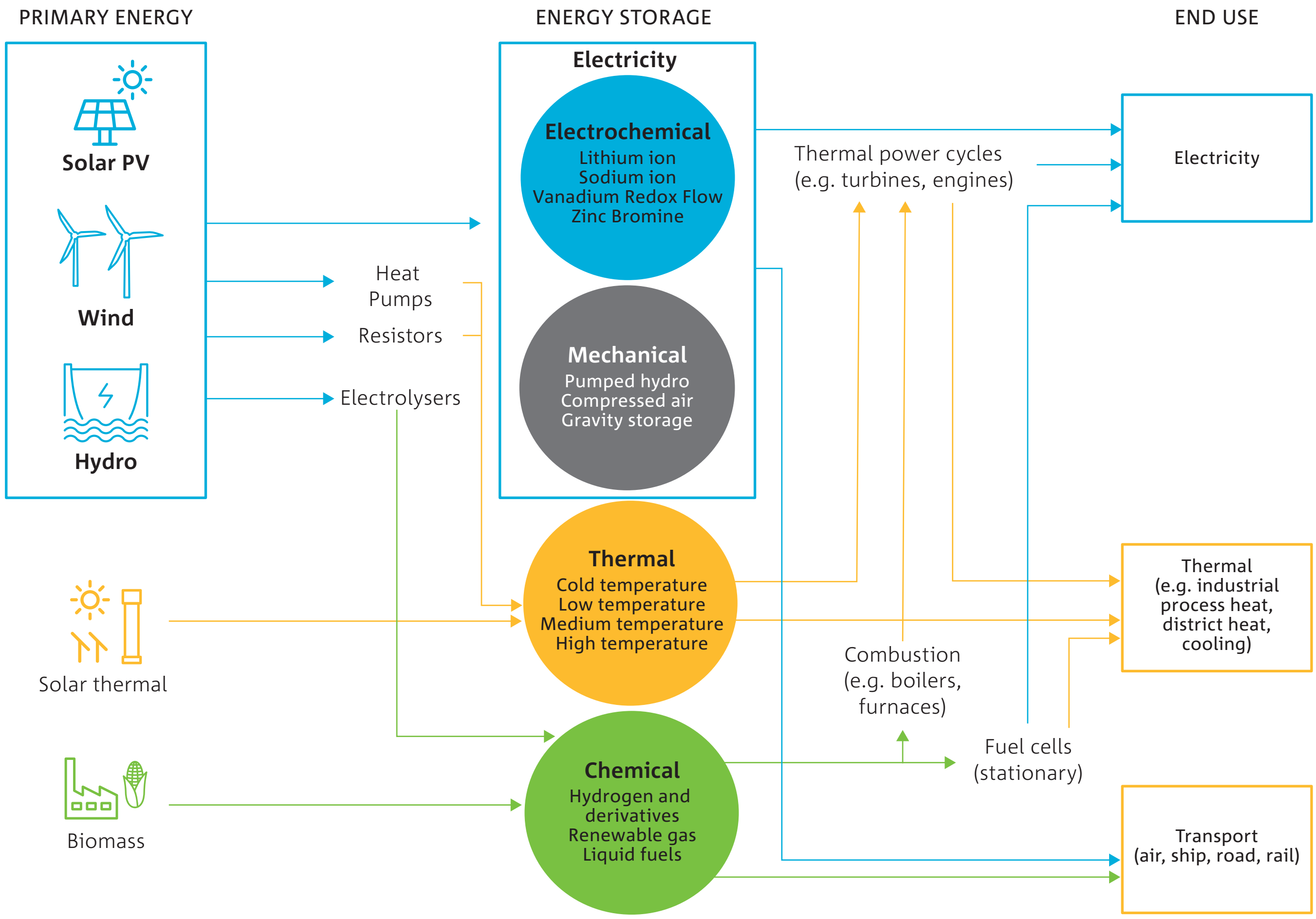


Deployment considerations

Once the role and need for energy storage is understood for a specific end-use application, stakeholders must assess deployment considerations that may influence technology selection and deployment efforts. As stated, these considerations are highly site specific, varying even among similar end-use applications and sectors, and must consider the entire energy system for a given site and region (see Figure 16).

The following section summarises a selection of these considerations, with further information related to cost discussed later in the context of LCOS analysis. Table 4 provides an overview of the key deployment considerations for technology options that are explored in Part III through the use of specific end-use sectors.

Figure 16: Role of renewable energy storage in Australia's energy system



Notes: Graphic developed in consultation with ITP Thermal. Terminology: PV, photovoltaic.

Table 4: Key storage deployment considerations

CONSIDERATION	OVERVIEW
Cost	Although deployment will generally focus on selecting a least-cost storage technology, costs are influenced by the entire energy system and how it is optimised to meet site needs. Therefore, although an individual technology may be identified as being low cost, it may not be the most optimal solution in the context of the overall system. Further, a given stakeholder may choose to invest in a higher-cost technology because of other deployment factors or perceived risks. Understanding and comparing technology-related costs can be difficult in the context of storage. These challenges and the LCOS approach used for this report are discussed later in this section.
Maturity	The maturity of an energy storage technology is key to understanding the current state of its development and commercialisation, tracking technological progress over time, and identifying the level of investment risk and near-term opportunities to meet gaps in energy storage demand. Importantly, consideration of technology maturity (based on commercial readiness) needs to account for full system maturity and context, rather than the maturity of the storage device on its own. This includes considering the maturity of the technology in different applications as its performance and the level of risk that exists can change. Maturity is discussed further in Section 2.1.
Economies of scale, modularity and scalability	Certain contexts require technologies that benefit from economies of scale (i.e. deploying high-capital expenditure [CAPEX], large-scale systems to decrease the average cost of storage per kWh). Other contexts require systems that are modular (i.e. easily deployed, relocated, or consisting of compartmentalised units that can be added), or technologies that can be incrementally scaled up at a relatively low cost per additional capacity added. This report does not cover the economies of scale achieved in large scale manufacturing of technology products (e.g. battery gigafactories to reduce the per unit cost of batteries).
Geographical and site characteristics	Geographical and site characteristics, such as local resources, proximity of infrastructure, geology, topography, temperatures, system requirements and land availability has the potential to affect applicability, technical performance, CAPEX or operational (OPEX) costs of some technologies.
Construction times and asset lifetime	Projects with long construction times often also come with longer planning and approval timelines. These timeframes will require the end-user to have a longer operational life, or projects will need to consider long term expected demand across multiple users in the region. Similarly, energy technologies with longer asset lifetimes will also require the intended end user to be operational and viable during that time, or be connected to multiple end users to ensure revenue certainty.
Serviceability and maintenance	The ability to locally service and maintain an energy storage asset can significantly impact costs, turnaround times and safety. This often relies on the presence of skills and capability in the area in which the asset is deployed, a domestic equipment manufacturer or a domestic supply chain.
System integration	Energy storage systems that are easy to integrate into an industrial site may be easier for end users. However, this will depend on the existing site infrastructure. Some contexts may benefit from the integration of multiple energy storage technologies into a hybrid storage systems.
Supply chain considerations	Reliance on critical minerals and materials, or the lack of diversification in value chains can pose a technology risk. Supply chain bottlenecks stemming from excess demand relative to supply, speculation in commodity markets and geopolitical developments can drive price volatility. There are also considerations with respect to investing in the supply chains of emerging technologies that employ specialised materials that are currently produced at small scales, to ensure a smooth path to scale up.
Safety and risk management	Safety and risk management is a key consideration particularly when deploying energy technologies in certain industrial facilities, in areas that are populated, or in areas with limited access to monitoring, maintenance and emergency services.
Social and environmental considerations	The social impacts of energy storage technologies include the land and water impacts of energy storage technologies, particularly where they impact on livelihoods or sites of cultural significance, job creation opportunities and ethical supply chain management. Although this report has not conducted a lifecycle analysis, the environmental impacts of energy storage technologies should be considered when investing.

Scope of technology options

To manage the scope of the report, a selection of representative sectors have been used to illustrate specific storage needs and technology options (see Figure 17). As such the technology analysis is not exhaustive and aims to provide examples of technology options that could be considered to meet specific requirements.

Given the various decarbonisation pathways that exist, cross-references have been included in sections to guide readers. For example, the mid-temperature and high-temperature industrial process analysis (Sections 3.5 and 3.6) focuses on thermal energy storage technology options. However, electricity or hydrogen may also be used to meet industrial process heat. In this instance, cross references to major and isolated grids have been included to explore electrification storage technology options and cross references to hydrogen export and transport have been included to explore hydrogen storage options. Similarly, while the focus of the remote mining discussion is on electricity storage, a cross-reference has been included to transport to explore the potential use of hydrogen in heavy mining vehicles.

Levelised cost of storage (LCOS)

This roadmap provides LCOS analysis to inform decision making and investment considerations across technologies. The analysis draws on Schmidt et al (2019) by defining LCOS as the sum of discounted costs per unit of delivered energy over an investment's lifetime, which is equivalent to the average price at which energy can be sold for the storage investment's net present value to be zero.[104] The approach separates the storage costs from the energy generation system costs to better understand the drivers of storage cost components.

There are several challenges with respect to modelling storage costs and comparing these across different energy storage systems. The definition of LCOS varies across existing literature which makes it difficult to compare the cost of energy storage technologies on a like-for-like basis across different sources. In addition, the cost estimates can vary significantly based on the deployment context (e.g. size and location of the storage system), which is not always made clear. Additional complexity to comparing costs arises when considering overall system costs under different configurations. For example, storage systems

Figure 17: Technology options analysis included in this report

	SECTION 3.2	SECTION 3.3	SECTION 3.4	SECTION 3.5	SECTION 3.6	SECTION 3.7	SECTION 3.8
	Major Grids	**Large-scale, isolated grids: Remote mining**	**Isolated microgrids: Remote communities**	**Mid-temperature industrial processes: Manufacturing**	**High-temperature industrial processes: Alumina refining**	**New energy exports: Hydrogen export**	**Transport: Heavy-duty hydrogen vehicles**
	Electricity energy storage (of different durations) to support Australia's major and isolated grids			Thermal and chemical energy storage to support industrial process heat requirements		Storage of hydrogen (as an example of large and distributed chemical energy storage) to support export and transport	
Electrochemical	✓	✓	✓	*		*	
Mechanical	✓	✓	✓	*		*	
Chemical	✓	✓	✓	*	*	✓	✓
Thermal	✓	✓	✓	✓	✓	*	

✓ Technology options explored in section

* Technology applies but not discussed in chapter, cross reference to other sections

104 Schmidt O, Melchior S, Hawkes A, Staffell I. Projecting the future levelized cost of electricity storage technologies. Joule 2019;3:81–100

can be employed alongside different sources of primary energy (e.g. wind or solar) and different end-use energy requirements (e.g. heat, electricity or hydrogen), and this will impact the overall cost estimated. Further, for emerging technologies, it is difficult to reliably estimate future costs because there are fewer projects compared with existing technologies. Finally, the cost of emerging energy storage technologies under development and demonstration phases can rapidly fall as they become increasingly commercial.[105] Although there are several approaches to projecting technology cost reductions, these face limitations, leading to uncertainty.

This section provides an overview of how to interpret LCOS estimates within this report and sensitivity analysis conducted to understand key model assumptions that influence costs. Further information on the LCOS approach can be found in Appendix C.

Interpreting LCOS results within this report

To help inform national discussion, this report has sought to be transparent by clearly communicating the assumptions and boundaries underlying the LCOS approach so that the differences to other estimates can be traced back to differences in the assumptions used.

Given the difference in methodology and assumptions across sources, the results should be used to gauge the relative cost of storage technologies given the set of assumptions used in this report, rather than the absolute cost of a particular technology.

LCOS components

Each LCOS result is subdivided into four components. These components are converted into a common unit ($/MWh) in the LCOS calculation.

- **Power capital cost**: This reflects the cost of the charging and discharging components of the system and varies per unit of power ($/kW, $/MW etc). For example, for a PHES system, the power components consist of pumps to raise the water to the dam, tunnels/pipes for water transfer and a turbine for generation.
- **Energy capital cost**: This is the storage component of the system, with costs varying per unit of energy ($/kWh, $/MWh etc). For example, for a PHES system, the energy components are the dams.
- **Charging cost**: This is the energy cost to charge the system. This energy is the required output, plus any losses incurred during the charge and discharge cycles. The round-trip efficiency is the output energy divided by the input energy. The charging cost is therefore the unit cost of energy ($/MWh or $/kWh etc.) multiplied by the energy required to charge the system.
- **OPEX**: This accounts for the ongoing operations and maintenance cost of the system. In this study it is calculated as a percentage of the total installed capital cost.

Cycles and duration

All LCOS results within this report refer to applications with specific assumptions related to annual cycles and storage duration. For example, the short-duration application example in Major Grids considers a storage technology with a 2-hour duration that is utilised 394 times over the course of a year. While these assumptions are based on renewable energy availability data and case studies, the exact durations and cycles should be viewed as examples. There are various factors that may change the storage duration and annual cycle assumptions (e.g. different weather patterns). As highlighted in the sensitivity analysis later in this section, changes in these assumptions can have a material impact on the LCOS results.

In practice, technologies can be used to meet several durations and take advantage of value stacking opportunities, for example, providing longer duration storage as well as short duration cycles to reduce overall LCOS. For simplicity and comparability, LCOS results have been presented for a specified duration and number of cycles.

LCOS comparison with fossil fuel alternative

The total cost of fossil fuel alternatives has been provided for comparison with each application analysed. These are represented by solid horizontal lines in the LCOS results. These cost comparisons include carbon pricing assumptions in 2025 and 2050 that are consistent with the net zero pathway developed in the demand modelling exercise (outlined in Appendix B). However, it should be noted that 2025 and 2050 gas prices do not reflect a continuation of the high gas prices seen in 2022. As this study is concerned with the longer-term needs of the energy system, this report has elected to exclude current gas price volatility from the analysis.

105 For example, the price of Li-ion battery cells (consumer electronics and automotive) fell by approximately 98% from 1995 to 2019: Kittner N, Schmidt O, Staffell I, Kammen DM (2020) Chapter 8 – Grid-scale energy storage. In Technological Learning in the Transition to a Low-Carbon Energy System. (Eds M Junginger, A Louwen) 119–143.

Commercial readiness

Technologies in the LCOS charts are ordered based on maturity levels (CRI) for the specific application examples identified in this analysis. Those to the left of the dotted pink line are considered commercial scale while those to the right are considered to still be at pilot scale. This maturity varies by application and duration. For example, while several technologies are at a commercial scale for the medium duration application (8-hour example), very few technologies have been deployed commercially and at a grid scale for long intraday applications (24-hour example).

Boundary diagrams

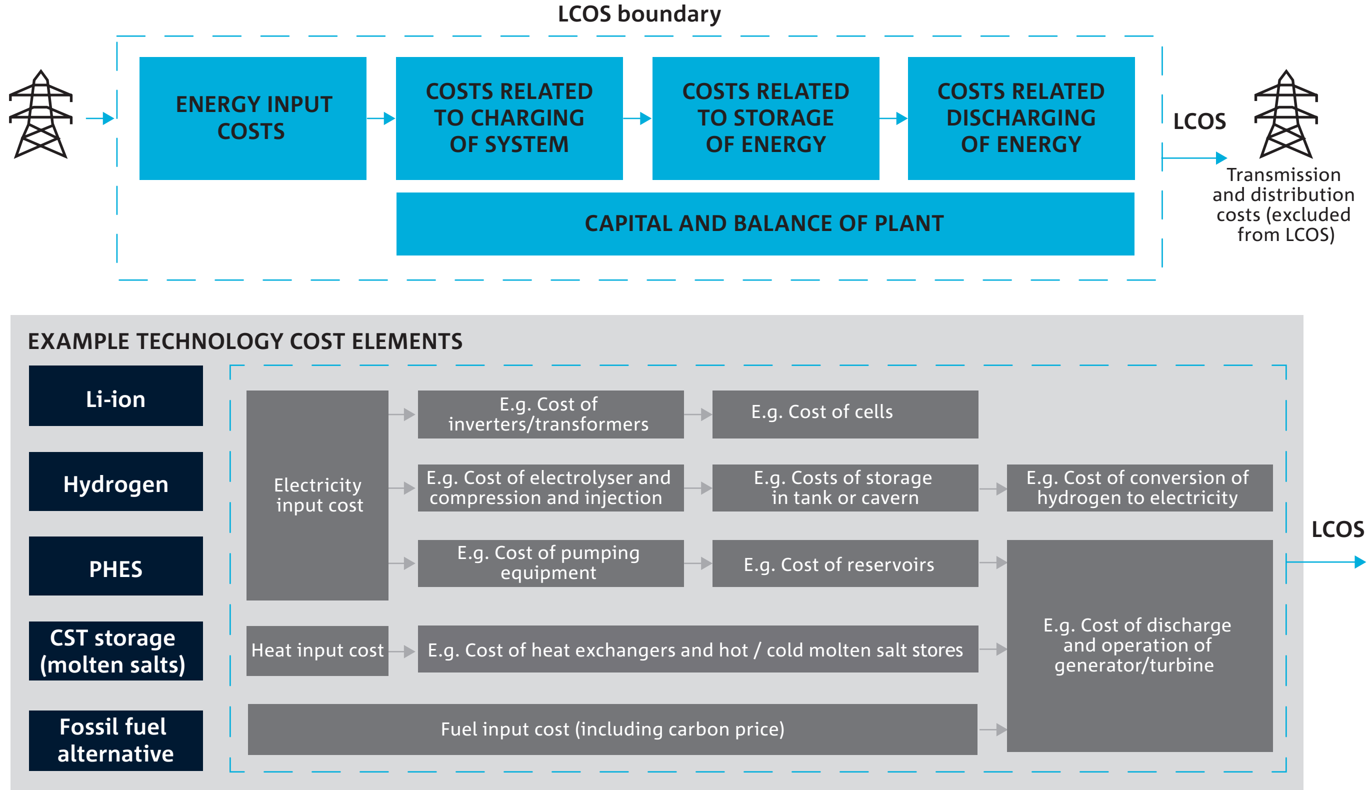
Boundary diagrams have been created to help stakeholders understand the scope of the analysis and to aid comparison and discussion of LCOS results. Figure 18 provides a simplified representation of the LCOS boundary used and examples of cost components for different energy storage types for an electrical application. Appendix C includes boundary diagrams for each technology considered.

Sensitivity analysis

Sensitivity analysis was conducted to better understand the input assumptions that have a major influence on LCOS results. Figure 19 provides an example of how adjusting some key inputs can have a large impact, the effect of adjusting other assumptions is minimal. For the specific case analysed, assumptions related to energy input costs (e.g. electricity price), annual cycles and capital costs can have a large impact on the results when looking across technologies. While the storage duration assumption will also have a large impact, this is explored in other parts of the report (e.g. the Major Grids section examines the LCOS for storage systems across a range of durations).

The example is based on one technology, which has been de-identified to highlight the general influence assumptions can have on LCOS results. Further sensitivity analysis would be required across technologies. Case 1 starts with 2025 LCOS for an 8-hr, 230 annual cycle electrical storage application with each case varying a single assumption as described in Figure 19.

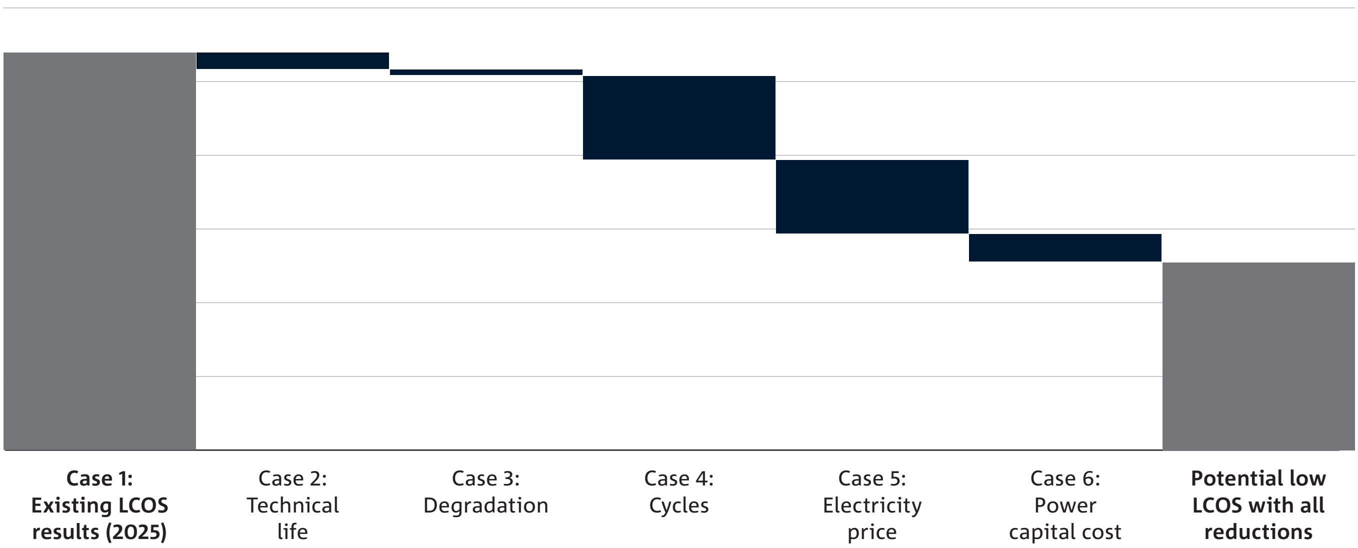
Figure 18: LCOS boundary and example of technology cost elements



Each of these assumptions are discussed for the case analysed:

- **Technical Life (Case 2):** For newer technologies, life expectancy can only be predicted based on experience, and there could be a case for a higher technical life in the future as technologies improve. The life expectancy was increased by roughly 40% to test how this assumption affected the LCOS. The result was a slight decrease in LCOS when compared to the other assumptions examined.
- **Degradation (Case 3):** It is assumed that all technologies have some degree of degradation, some more than others. To test the effect on the LCOS, the system degradation assumption in this case was reduced to zero. As can be seen, this has little effect on the overall LCOS when compared to other assumptions examined.
- **Annual cycles (Case 4):** Increased utilisation of a storage asset naturally influences the LCOS. A comparison was done between the assumption of fully charging and discharging an asset 230 times in the year (which could reflect partial charging on some days) versus the assumption of full charge and discharge daily (365 times year). While this report uses information on renewable energy availability and case study data to support analysis, the annual cycle assumptions employed in industry analysis can be higher. Careful consideration is required to validate that a technology can be operated at that frequency.
- **Energy input costs (Case 5):** For simplicity this report uses fixed 2025 and 2050 electricity price assumptions across all technologies. It is important to acknowledge that in many cases charging of storage technologies will occur when renewable energy prices are low, and therefore the average price could be lower than the main assumption in this report. However, the daily availability of consistently low prices across all regions is not guaranteed. This is particularly important when considering the charging of longer duration applications of 8 hours and above and the desire for high utilisation (or annual cycles). Despite this, we test a case where the electricity price is halved from 6¢/kWh_e to 3¢/kWh_e to illustrate that the ability to charge storage systems when energy prices are very low will have a material impact on the LCOS.
- **Power capital cost (Case 6):** For simplicity, capital cost assumptions used in this report are largely based on CSIRO GenCost 2022[106] and/or independent, peer-reviewed literature studies (see Appendix C for details). However, stakeholder interactions highlighted the potential for alternative capital cost assumptions. These potential assumptions could be influenced by project or site-specific factors (e.g. the potential to repurpose existing infrastructure in a region), different system size assumptions (e.g. larger deployments being considered overseas) or recent vendor quotes for specific componentry. We therefore test the impact from an approximately 30% reduction in capital costs. These assumptions require further analysis and interrogation on a project-by-project basis.

Figure 19: Influence of assumptions to create a potential low LCOS result



106 Graham, P., Hayward, J., Foster J. and Havas, L. 2022, GenCost 2021-22: Final report, CSIRO, Australia

3.2 Major grids

Major grids will require a significant scale of storage of varying durations to manage imbalances in electricity supply and demand as they transition. There are limited commercially mature (bankable) energy storage options in Australia that are deployable in the near term, and the most widely deployed systems in Australia, li-ion and PHES, face supply chain risks and geographical constraints respectively.

Major grids consist of transmission networks of high-voltage electricity across large distances and distribution networks that deliver electricity from the transmission system to households and businesses. Australia's major grids are diverse, with both interconnected and isolated grid systems in place to serve various states and territories. These include:

- **East and south-east Australia:** Australia's east and south-east states and territories are serviced by the NEM, one of the longest interconnected electricity markets in the world, spanning over 5,000 km.[107]
- **WA:** WA has two separate major electricity systems, the South West Interconnected System (SWIS) and the North West Interconnected System (NWIS).
- **Northern Territory:** The Northern Territory consists of three separate smaller electricity systems, the Darwin–Katherine Interconnected System, the Tennant Creek network and the Alice Springs network.[108]

	MAJOR GRIDS Electricity energy storage (of different durations) to support Australia's major and isolated grids
Electrochemical	✓
Mechanical	✓
Chemical	✓
Thermal	✓

✓ Technology options explored in section

107 ARENA (2019) Lessons from the fringes Australian off grid projects. <https://arena.gov.au/assets/2019/06/lessons-from-the-fringes-australian-off-grid-projects-arena-portfolio.pdf> (accessed 16 May 2022).

108 Climate Council (2018) Australia's energy system. <https://www.energyfactsaustralia.org.au/explainers/australias-energy-system/> (accessed 26 May 2022).

Beyond managing a rapidly evolving generation mix underpinned by a phasing out of coal operations and growth in VRE deployment, energy storage is expected to play a key role in Australia's major grids (as discussed in Part I). However, it will be important that a mix of storage systems is considered to account for the differences in Australia's grids compared with those overseas, as well as the differences in system requirements even within the same region.

As mentioned earlier, Australia's grids cover long distances, such as the 290-km connection between Victoria and Tasmania on the NEM, one of the longest submarine power cables in the world.[109] Australia's grids are also low density, given there are six interconnectors linking five states across the NEM.[110] In comparison, Europe has 82 interconnections linking the European Union and 10 countries.[111] These high-density, meshed networks overseas allow countries such as Denmark to integrate around 49% wind power without major curtailments, because excess energy output can be used or stored by neighbouring countries.[112]

Australia also has distinct characteristics and requirements across interconnected and isolated grid systems. For example, in addition to the SWIS (centred on Perth) and NWIS (in the Pilbara region, including Karratha and Port Hedland), WA also has the Kununurra–Wyndham–Lake Argyle network and 34 other microgrids covering the many remote customers of WA.[113] Although each system is electrically isolated, many WA systems are supplied by a common gas network, in which the Goldfields Gas Transmission Pipeline and the Dampier to Bunbury Natural Gas Pipeline have major roles.[114] The isolation of WA electricity grids serves to create distinct characteristics in each system, meaning that no two systems will have the same combination of demand, generation requirements and system services. For example, the NWIS is dominated by both demand for industrial customers and gas-fired power generation, whereas residential customers on the south coast of WA have a large proportion of energy generated by wind farms.

Role of energy storage

As highlighted in Part I, there is expected to be a large increase in energy storage demand as Australia's electricity sector transitions to net zero. Storage can be used in numerous ways to support the supply of safe, reliable and cost-effective electricity as Australia's major grids transition and evolve over time. Different storage applications in the power sector include, but are not limited to:

- **Time shifting energy:** Storage will play an increasing role shifting energy supply to match later periods of demand. As discussed in Part I, increasing levels of VRE, such as rooftop PV installations, are expected to supply an increasing proportion of Australia's electricity needs. Storage can help firm the supply of variable renewable power by storing energy at high-generation (low-price) periods and saving it for use at low-generation (high-price) periods.[115]

109 Australian Energy Regulator (2009) State of the energy market 2009. Australian Government. <https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-2009> (accessed 22 November 2022).

110 AGL Energy (2019) Explainer: The national electricity market. <https://www.agl.com.au/thehub/articles/2019/05/explainer-the-national-electricity-market> (accessed 2 June 2022).

111 Directorate-General for Energy (European Commission) (2019) Electricity interconnections with neighbouring countries: second report of the Commission expert group on interconnection targets. Publications Office of the European Union. <https://op.europa.eu/en/publication-detail/-/publication/785f224b-93cd-11e9-9369-01aa75ed71a1> (accessed 22 November 2022).

112 IRENA (2019) Innovation landscape for a renewable-powered future: Solutions to integrate variable renewables. IRENA, Abu Dhabi.

113 Horizon Power (2020) Connecting vibrant communities: Annual report 2019/2020. <https://web.horizonpower.com.au/media/6027/2020-a4-annual-report-final.pdf> (accessed 22 November 2022).

114 Department of Mines, Industry Regulation and Safety (2021) Energy Infrastructure Map 2021. Government of Western Australia, Energy Policy WA <https://www.wa.gov.au/system/files/2021-12/Energy_Infrastructure_MAP_A0_Aug_2021_o.pdf>

115 Schmidt O, Melchoir S, Hawkes A, Staffell I (2019) Projecting the future levelized cost of electricity storage technologies. Joule 3, 81–100; Aurecon (2020) 2020 Costs and technical parameter review: Consultation report. Aurecon, Brisbane.

116 AEMO (2022) 2022 integrated system plan (ISP). <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp> (accessed 22 November 2022).

117 Cavanagh K, Ward J, Behrens S, Bhatt A, Ratnam E, Oliver E, Hayward J (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

- **Avoiding or deferring transmission and distribution (T&D) investment:** Storage and T&D are complementary and must be analysed together to help optimise network developments more efficiently than considering storage or T&D in isolation. This is important given the scale and pace of change required to support Australia's energy transition. For example, across the NEM, 10,000 km of T&D infrastructure will be required by 2050 under the *Step Change* scenario.[116] Alongside T&D investments, rapidly deployable storage technologies could offer grid support where T&D deployment time frames are long or where T&D costs are prohibitive.[117]
- **Network support:** Storage can support grid stability by managing changes in energy supply or demand across the network.[118] As levels of VRE increase across Australia's major grids (see Part I), network support services, such as frequency control ancillary services (FCAS), may be required to manage the intermittent nature of power supplied. This increasing need can be seen, for example, in the NEM, where total FCAS costs in 2020 were approximately A$356 million, fivefold greater than 2015 levels.[119] Storage can help address this demand by quickly drawing or injecting power into the grid when needed to maintain grid voltage and frequency within specified limits. Storage can also support network stability by correcting longer-term imbalances between VRE generation and demand.
- **Seasonal storage:** Storage can be used to manage variation in supply and demand or long-term disruptions to energy supply.[120] As Australia's grids shift to predominantly VRE supply by the mid-2030s (see Section 1.2), this change in generation may present a risk that there is a net surplus or deficit of energy over long periods of time. Some of these events may require high-capacity, long-duration or seasonal storage. However, the seasonal mismatch of energy supply and demand is relatively small in Australia and is likely to require smoothing for a matter of days or weeks, rather than months, as in other parts of the world.[121]

Alongside energy storage, there are various complementary or alternative options available to support Australia's major grids during transition. Examples include controlling grid frequency and/or voltage through inverters,[122] the use of synchronous renewable energy, synchronous condensers and flexibly controlled wind turbine output [123] and pricing incentive schemes.[124] Time-of-use pricing can also manage supply–demand imbalances by helping shift electricity consumption to better match high-generation periods.[125]

118 Schmidt et al. (2019) Projecting the future levelized cost of electricity storage technologies. Joule 3, 81–100.

119 AER (2020) State of the energy market 2021 – Chapter 2 – National electricity market. <https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202021%20-%20Chapter%202%20-%20National%20Electricity%20Market_0.pdf> (accessed 22 November 2022).

120 Schmidt et al. (2019) Projecting the future levelized cost of electricity storage technologies. Joule 3, 81–100.

121 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

122 Denholm P, Mai T, Kenyon R, Kroposki B, O'Malley M (2020) Inertia and the power grid: A guide without the spin. National Renewable Energy Laboratory. <https://www.nrel.gov/docs/fy20osti/73856.pdf> (accessed 24 October 2022).

123 Butler T (2017) Managing frequency in a modern electricity system. RenewEconomy. <https://reneweconomy.com.au/managing-frequency-modern-electricity-system-85447/> (accessed 11 July 2022).

124 CSIRO and Energy Networks Australia (2017) Electricity network transformation roadmap: Final report. <https://www.energynetworks.com.au/resources/reports/electricity-network-transformation-roadmap-final-report/> (accessed 24 October 2022).

125 Friis F, Christensen T (2016) The challenge of time shifting energy demand practices: Insights from Denmark. Energy Research & Social Science 19, 124–133.

Deployment considerations

To enable the storage applications (discussed previously), grid storage systems may require different storage technology types and durations, each with differing deployment considerations. Although not exhaustive, this section builds on the considerations discussed in Section 3.1 to highlight specific storage deployment considerations related to major grids.

- **Cost:** Cost considerations are complex and can vary by the storage service provided to a major grid, as well as the region being considered (including local energy resources and T&D infrastructure), in addition to other factors. To support technology cost discussions, demand modelling results from Part I have been used to identify a selection of example electrical storage applications (see LCOS analysis later in this section).
- **Maturity:** The power sector may focus on mature technologies (CRI 3 or above) given their ability to provide a return on investment through the electricity market. However, given the difficulties and costs in providing long-duration or seasonal energy storage, the power sector may seek funding support for technologies that require further development and demonstration (CRI 1–2) where there are clear gaps.
- **Economies of scale:** Large storage systems with high fixed capital costs can lower their cost per unit of output when they increase in size, particularly when deployed at utility scale on the grid. This is in comparison with modular systems, which benefit relatively less when many units are deployed at utility scale.
- **Geographical and site characteristics:** Available sites and locations for grid storage may limit the deployment of some technologies that require geographical or geological conditions for their operation. Although suitable sites may be identified in remote or distant areas, transmission connection costs would also need to be considered to accurately assess technology feasibility.
- **Construction time:** It is assumed that construction time frames (and lead time for planning and approvals) will generally need to be short (5 years or less) to support 2030 renewable energy targets. Given these time frames, it may be difficult for technologies in the development or demonstration stage to contribute significantly. However, the power sector may be open to longer-term investments to meet storage demand past 2030 or in states and territories with longer-term renewable energy targets.
- **Supply chain considerations:** Given the global demand for energy storage, power providers operating across Australia's major grids will need to assess the supply chain risks of energy storage technologies being considered. Where there is a risk that deployment time lines and decarbonisation objectives could be disrupted, technology alternatives with fewer supply chain issues may become more attractive.
- **Safety and risk management:** Given major grids are near densely populated areas and storage systems are deployed at large utility scales, the sector will need to assess potential risks to the safety of workers and surrounding communities. Risk management also considers resilience to fire, flood and prolonged high ambient temperatures.

- **Social and environmental considerations:** In addition to safety, the social and environmental impact of storage systems will be important for technology selection. This may include various societal considerations, such as system noise and heat produced, ethical and sustainable supply chain management and job creation opportunities. This may also include various environmental considerations, such as biodiversity management, water and land use and the end-of-life management of assets.[126]

Technology options

Different storage durations and technology options can be used for different applications. As such, this section explores technology options across different storage durations:

- **Short-duration storage (between 1 and <4 hours)** can play multiple support roles on the grid, offering value-stacking opportunities in the electricity market. Short-duration storage can be used for applications discussed earlier, such as network support, time shifting energy and helping avoid or defer T&D investment.
- **Medium-duration (from 4 to <12 hours)** storage systems can play an important role providing major grids with the flexibility to manage any imbalances between supply and demand, as well as supporting grid capacity. Medium-duration storage systems can be used for applications such as network support, time shifting energy and helping avoid or defer T&D investment. Demand modelling for storage at this duration is discussed earlier in Section 1.2.
- **Long intraday (from >12 to 24 hours)** storage is used for network support to help stabilise day-to-day variation in electricity supply and the time shifting of energy to manage differences between peak VRE generation and peak energy use times each day.
- **Multiday (from >24 to 100 hours) and seasonal (>100 hours)** storage can play a role managing significant and long-term imbalances between electricity supply and demand, discussed earlier as seasonal storage.

The technology options are not exhaustive and provide examples of the application of deployment considerations discussed above. A summary is provided in Table 5 and Table 6. A quantitative LCOS analysis has been performed for a subset of these technologies to provide a point of comparison for the modelled assumptions (see next section).

More information on each of the technologies, and the approach to LCOS modelling, can be found in Section 2.2, Section 3.1 and Appendices C and E.

Pumped hydro energy storage

PHES is internationally deployed and commercially competitive (CRI 6) and capable of medium, long and seasonal grid storage. Small-scale systems are undergoing supported commercial deployments (TRL 9/CRI 4). There may be limits to the ability of PHES to address medium-duration demand by 2030 (see Part I) due to development time frames and geographical requirements. For long and seasonal storage, PHES may be limited in regions due to dam requirements. Although construction times are between 3 and 7 years, PHES can also include long development lead times to obtain funding and approvals. Topographical requirements of PHES are also limiting factors for regions without suitable elevations, resulting in PHES systems not being applicable for deployment in all regions.

126 Social and environmental considerations for storage technologies can be found in Appendix E.

Table 5: Summary of applicable durations for energy storage technologies in utility scale grid applications

DURATION	PHES	Li-ion batteries	CsT (molten salts)	VRFB
Maturity (CRI)[127] in grid scale applications	6	5–6 (short duration) 3-4 (medium duration)[128]	4–5 3–4 (small scale)	3–4 3 (long duration)
Short (<4 hours)	◐	●	◐	●
Medium (4 to 12 hours)	●	●	●	●
Intraday storage (>12 to 24 hours)	●	○	●	○
Multiday storage (>24 to 100 hours)	●	○	◐	○
Seasonal storage (>100 hours)	●	○	○	○

Legend: ● Likely commercial applicability ◐ Partial commercial applicability ○ Unlikely commercial applicability or insufficient data in specified duration for grid-scale use

Notes: The labels represent the different technologies considered within this report for the specific durations and cycles analysed for utility scale storage. This is based on LCOS analysis, desktop research and stakeholder consultation and should not be considered definitive. An LCOS analysis was not performed for LAES, ZNBR Na-ion and gravity due to insufficient data and/or low maturity, as such these are based on stakeholder consultation and desktop research. Terminology: A-CAES, adiabatic compressed air energy storage; CST, concentrated solar thermal; eTESe, thermal energy storage (electricity input, electricity output); LAES, liquid air energy storage; PHES, pumped hydro energy storage; VRFB, vanadium redox flow batteries; ZNBR, zinc–bromine batteries.

Table 6: Summary of deployment considerations for energy storage technologies in utility scale grid applications

CONSIDERATION[129]	PHES	Li-ion batteries	CsT	VRFB	A-CAES
Economies of scale	Large opportunity to reduce cost per kilowatt for larger systems	Small opportunity to reduce cost per kilowatt for larger systems	Large opportunity to reduce cost per kilowatt for larger systems	Moderate opportunity to reduce cost per kilowatt for larger systems	Large opportunity to reduce cost per kilowatt for larger systems
Geographical and site characteristics	Topography requirements Water requirements Large footprint	Flexibly deployed Utility scale has larger footprint Operating temperature 0–45°C	Solar resources Large footprint (including solar array)	Flexibly deployed Utility scale has larger footprint Operating temperature from –15°C to 50°C	Geological requirements Moderate above-ground footprint
Construction times	3–7 years	8–20 weeks	<2 years	1–1.5 years	2.5–3.5 years
Use of critical materials[130]	Low	High – lithium cobalt, nickel, manganese (varies by battery type)	Moderate – (depends on alloy type)	Moderate – vanadium	Low

Terminology: A-CAES, adiabatic compressed air energy storage; CST, concentrated solar thermal; eTESe, thermal energy storage (electricity input, electricity output); LAES, liquid air energy storage; PHES, pumped hydro energy storage; VRFB, vanadium redox flow batteries; ZNBR, zinc–bromine batteries.

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127 Explanation of maturity can be found in Section 2.1; References can be found in Appendix E.

128 CRI 4 for a duration of 4 hours; CRI 3 for a duration of 8 hours.

129 Explanation of the criteria can be found in Deployment Considerations in Section 3.1; References can be found in Appendix E

130 A supply chain analysis for each technology was not conducted; Geoscience Australia (2021) Australian critical minerals prospectus 2021. Available at <https://www.austrade.gov.au/news/publications/australian-critical-minerals-prospectus-2021> (accessed 22 November 2022); Bruce S, Delaval B, Moisi A, Ford J, West J, Loh J, Hayward J (2020) Critical Minerals Roadmap. CSIRO, Australia.

A-CAES	LAES	ZNBR	Underground hydrogen	eTESe (molten salts)	Na-ion batteries	Gravity
2–3	2	2	1–2	1–2	1	1
◑	◑	●	◑	◑	●	◑
●	●	◑	○	●	●	●
◑	◑	○	●	●	○	◑
○	○	○	●	○	○	○
○	○	○	●	○	○	○

LAES	ZNBR	Underground hydrogen	eTES	Na-ion batteries	Gravity
Moderate opportunity to reduce cost per kilowatt for larger systems	Small (gel type) to moderate (flow type)	Large opportunity to reduce cost per kilowatt for larger systems	Moderate opportunity to reduce cost per kilowatt (depending on system type)	Small opportunity to reduce cost per kilowatt for larger systems	Moderate to large (depends on system type)
Flexibly deployed Moderate footprint	Flexibly deployed Utility scale has larger footprint Operating temperature 10–45°C	Geological requirements Moderate above-ground footprint	Flexibly deployed Moderate footprint	Flexibly deployed Utility scale has larger footprint Operating temperature from –30°C to 60°C	Geographical and footprint requirements depend on system type
Expected to be 2 years	Approx-imately 9 months	1–5 years	Insufficient data	Insufficient data	1–3.5 years, depending on system type and site
Low	Low	Low	Low	Low	Low

Lithium ion batteries

Li-ion batteries have reached competitive commercial deployment (CRI 5–6) for short-duration grid use and are still being supported for commercial-scale deployments (CRI 3-4) for medium-duration (beyond 4 hours) grid storage. Although Li-ion batteries benefit from a modular design and can be constructed in short time frames (8–20 weeks), cost competitiveness can be affected by supply chain conditions, including production bottlenecks in the face of high global demand.[131] Costs and efficiency may also be affected when Li-ion batteries are used in warmer (>45°C) environments due to the need for air conditioning units.

Concentrated solar thermal plus storage

CST plus storage has reached competitive commercial deployment (CRI 4–5) for grid-scale power applications and has the ability to provide medium and long intraday storage to the grid. CST plus storage is currently being demonstrated in Australia for electrical applications. However, there are multiple international projects that have been deployed. CST plus storage can offer a construction time of <2 years. However, geographical considerations may limit the use of this technology to sunny, remote or regional areas given utility scale CST plants require land for solar collectors and high solar irradiation.

Although molten salts are the most commercially mature thermal storage deployed with CST, there are several other media that can be considered. Concrete and packed beds can also be used as CST thermal storage media and benefit from being a low-cost, easily supplied medium and achieving a wider working temperature range than molten salts.[132] Demonstrations include the 4-MW Airlight Energy CST plant in Morocco, which uses a packed bed of rocks.[133] Other media that can be considered for CST include particle systems (i.e. falling particles), which have been piloted at CSIRO's Newcastle facility and will be piloted at megawatt-scale in the US (TRL 5–6/CRI 1). MGAs are at pilot scale but are targeting grid-scale storage in the future.[134] Graphite could be considered for CST in the future, but this is not currently the target market for Australian technology proponents.

Although the scope of this roadmap is focused on the storage media discussed above, alternative CST systems that use hot and cold water are also being demonstrated. For example, RayGen is demonstrating grid-scale storage in its Carwarp project in Victoria, which will include 17 hours of storage (3 MW/50 MWh).[135]

Vanadium redox flow batteries

VRFB are involved in supported commercial deployments (CRI 3–4) and are best suited to short- and medium-duration grid use. Commercial demonstrations for long intraday utility scale storage (CRI 3) are also underway. VRFB are less cost competitive than Li-ion batteries for shorter durations, but can operate in higher temperatures and have a reduced fire risk than Li-ion batteries, allowing them to be stacked where space is constrained and deployed in areas where temperatures are a challenge. Short (1–1.5 years) construction times may support this technology to address medium-duration demand before 2030. Large-scale grid use of VRFB is reliant on the scale up of the vanadium supply chain, which is currently small scale in Australia.[136] Air conditioning may also be required at high temperatures (>50°C).

Compressed air

A-CAES is currently engaged in commercial-scale demonstrations (CRI 2–3), including planned grid-scale projects in Australia and internationally. A-CAES benefits from a moderate footprint compared to larger systems such as pumped hydro, and faces moderate development times (2.5–3.5 years). These systems benefit from economies of scale for large grid-scale use and underground storage capacity may also be incrementally scaled via excavation. Grid-scale demonstrations for A-CAES are planned in Australia and internationally. The system is geologically constrained to areas where hard rock caverns are available, but other types of geologies that could be suitable are under investigation as well as repurposing engineered caverns.

131 Bruce S et al. (2021) Critical Energy Minerals Roadmap. CSIRO, Australia.

132 Kraemer S (2019) Novel CSP design combines the solar receiver with thermal energy storage. Solar PACES, IEA Energy Technology Network. <https://www.solarpaces.org/novel-csp-design-combines-the-solar-receiver-with-thermal-energy-storage/> (accessed 22 November 2022); Martins et al (2015) New concentrating solar power facility for testing high temperature concrete thermal energy storage. Procedia 75, 2144–2149.

133 Zavattoni et al. (2018) Numerical analysis of the backed bed TES system integrated into the first parabolic trough CSP pilot-pant using air as heat transfer fluid. AIO Conference Proceedings 2033, 090027.

134 MGA Thermal (2020) MGA applications – grid-scale renewable energy. <https://mgathermal.com/blog/mga-applications-grid-scale-renewable-energy> (accessed 22 November 2022).

135 RayGen (2022) RayGen power plant – Carwarp. < https://raygen.com/projects/raygen-power-plant> (accessed 22 November 2022).

136 Bruce et al. (2021) Critical energy minerals roadmap. CSIRO, Australia.

Liquid air

LAES systems are in the pilot-scale demonstration phase (CRI 2) with a variety of medium-duration and grid-scale international projects either being constructed or planned to be constructed.[137,138] LAES systems are also capable of intraday storage, but this has not yet been demonstrated. LAES systems benefit from minimal geographical considerations given they can be deployed above ground, and can benefit from being deployed close to industrial processes and systems to recover waste cold and waste heat streams. Other benefits include their high energy density (compared with CAES) and short construction time frames (early commercial-scale facilities are expected to be completed within 2 years).[139]

Zinc–bromine batteries

ZNBR batteries are currently involved in pilot-scale demonstrations for grid use for short- and medium-duration storage (CRI 2).[140] Similar to VRFB, ZNBR batteries are expected to offer partial economies of scale, and can be modular and scaled to increase capacity. Although ZNBR batteries have a low energy density and utility scale deployments may have a larger footprint, these batteries can be stackable. Deployments of ZNBR batteries typically have short construction times (<1 year) and minimal safety and risk management issues. ZNBR batteries also benefit from using abundant materials, such as zinc, lowering supply chain risks.[141] It is unclear whether ZNBR battery systems will be able to meet medium-duration grid storage demand by 2030. Like other battery technologies, air conditioning may be required at high temperatures (>45°C). Technical challenges include round-trip efficiency and complex design and manufacturing requirements for flow-type ZNBR batteries.

Underground hydrogen

Underground hydrogen storage offers significant storage capacities and is capable of providing intraday, multiday and seasonal storage, limited primarily by the volume of available underground sites. However, for the 24- and 48- hour storage applications analysed, underground hydrogen storage was not found to be competitive against other technologies analysed, although it was competitive against gas peakers in the long term (see Figure 23 and Figure 24). However, very few storage options were identified that could operate at multiday or seasonal durations and at the scale required for Australia's major grids. Underground storage is less mature (CRI 1–2) than hydrogen tank storage and requires longer development times (2–3 years). In addition, deployment may be limited by geographical considerations because salt caverns are the most mature (CRI 2) geological subsystem for power applications.

Thermal energy storage systems

Standalone eTESe systems with a VRE input source can be used with a variety of thermal storage mediums. Molten salt eTESe systems are at pilot-scale demonstrations (CRI 1–2). As already discussed in the context of CST, molten salts can be used for medium-duration and intraday storage. Molten salts are the most mature form of thermal storage to date and can be deployed in a compact form (spanning a few metres); however, these systems require temperatures to be maintained above melting point or the use of antifreeze systems, and require regular maintenance.

There are several thermal media that benefit from modularity and scalability, which can be helpful in de-risking projects and scaling up from demonstration to commercial scale. Silicon can be used in eTES systems to provide firming services to the grid (TRL 4–5/CRI 1), for example 1414 Degree's TESS-GRID technology.[142] Graphite thermal energy storage systems have been demonstrated in a hybrid solar PV and eTESe power plant (CRI 1–2).

137 Highview Power (2020) Highview Power Breaks Ground on 250MWh CRYOBattery Long Duration Energy Storage Facility < https://highviewpower.com/news_announcement/highview-power-breaks-ground-on-250mwh-cryobattery-long-duration-energy-storage-facility/> (accessed 24 November 2022); Highview (2018) Highview Power launches world's first grid-scale liquid air energy storage plant. <https://highviewpower.com/news_announcement/world-first-liquid-air-energy-storage-plant/> (accessed 12 October 2022).

138 Enlasa (2022) About us. < https://www.enlasa.com/sobre-nosotros/> (accessed 24 November 2022); Enlasa (2022) Energy Storage < https://www.enlasa.com/almacenamiento-larga-duracion/> (accessed 24 November 2022)

139 Figure indicates construction time for a 50-MW/300-MWh system based on the construction schedule for Highview's CRYOBattery facility in Manchester, UK: MAN Energy Solutions (2021) MAN Energy Solutions confirms world-first LAES project. <https://www.man-es.com/company/press-releases/press-details/2021/07/14/man-energy-solutions-confirms-world-first-laes-project> (accessed 23 November 2022).

140 Redflow (2021) Redflow completes 2 MWh installation in California. <https://redflow.com/project/redflow-completes-2-mwh-installation-in-california> (accessed 17 November 2022); Redflow (n.d.) Data sheet: energy pod 200. <https://redflow.com/wp-content/uploads/2022/04/RDF0941-Redflow-Energy-Pod-FAWEB.pdf> (accessed 18 November 2022).

141 Bruce et al. (2021) Critical energy minerals roadmap. CSIRO, Australia.

142 1414 Degrees (2019) 1414 Degrees acquiring Aurora Project near Port Augusta. <https://1414degrees.com.au/acquiring-aurora-project/> (accessed 22 November 2022).

Concrete and packed bed systems have been demonstrated internationally for heat applications in district heating and manufacturing and are at CRI 2–3, but could be used in an eTESe system to generate electricity. MGA systems are undergoing RD&D (CRI 1) and are expected to be an intraday (24-hour) storage system, although longer durations are also possible.[143]

Sodium ion batteries

Na-ion batteries are in the RD&D phase (CRI 1) of technology development, are applicable for both short- and medium-duration storage and are being considered as a drop-in replacement for Li-ion batteries. Due to the abundance of materials, these batteries have low supply chain risks and have the potential to be lower cost that current Li-ion batteries.[144] Because these systems are modular, economies of scale can be limited for utility scale grid use. However, the potentially lower costs could support larger-scale, longer-duration storage projects than current utility scale battery projects. Further, Na-ion batteries have shown potential to operate at longer durations than Li-ion batteries.[145] Wider operating temperatures could also enable deployments in warmer areas, with less need for air conditioning.[146,147]

Gravity

Gravity storage systems are currently undergoing pilot-scale demonstrations (CRI 1–2) for medium duration storage and are expected to provide long intraday storage. Large-scale grid use can help achieve economies of scale for fixed installation costs of gravity storage and the systems are expected to have moderate expected construction times (1–3.5 years depending on system type and site characteristics).[148] System capacity or size can be constrained by the site available and varies by system type.

Alternative technologies

The technologies discussed are not exhaustive and there are several lower CRI storage alternatives that could be considered for different durations. Alternative battery chemistries, such as sodium sulfur batteries and polysulfide bromine batteries, can provide grid storage at different durations.[149] Alternative chemical carriers (e.g. methanol, ammonia, liquid organic hydrogen carriers) could also be considered to address long and seasonal storage demand.[150] For example, Woodside Energy, IHIM JERA and Marubeni are jointly conducting a feasibility study on ammonia co-fired power, aiming to overcome emission and cost challenges.[151]

Although beyond the scope of this report, demand-side flexibility through sector coupling should also be considered to reduce the need for storage, improve efficiency and reduce overall system costs. Examples include coordinated EV charging, smart homes and buildings, reducing electricity demand for heating (via the use of thermal storage and energy efficient technologies) and integrated systems.

143 MGA Thermal (2022) MGA Thermal pilot. <https://mgathermal.com/pilot> (accessed 8 November 2022); LDES Council (2022) Net-zero power: Long duration energy storage for a renewable grid. McKinsey & Company. <https://www.mckinsey.com/capabilities/sustainability/our-insights/net-zero-power-long-duration-energy-storage-for-a-renewable-grid> (accessed 8 November 2022).

144 Karabelli D, Singh S, Kiemel S, Koller J, Konarov A, Stubhan F, Miehe R, Weeber M, Bakenov Z, Birke KP (2020) Sodium-based batteries: In search of the best compromise between sustainability and maximization of electric performance. Frontiers in Energy Research. doi:10.3389/fenrg.2020.605129

145 Wang Y, Hou B, Ning Q, Pang W, Wang J, Lu C, Wu X (2018) An ultralong lifespan and low-temperature workable sodium-ion full battery for stationary energy storage. Advanced Energy Materials 8, 1703252; Natron Energy (2022) Introducing BlueTray® 4000. <https://natron.energy/product/> (accessed 8 November 2022).

146 Spoerke E, Gross M, Small L, Percival S (2020) Sodium-based battery technologies. In U.S. DOE Energy Storage Handbook. <https://www.sandia.gov/ess/publications/doe-oe-resources/eshb> (accessed 20 May 2022).

147 Zeng Z, Jiang X, Yuan D, Ai X, Yang H, Cao Y (2016) A safer sodium-ion battery based on nonflammable organic phosphate electrolyte. Advanced Science, 3, 1600066.

148 Approximately 1 year for a dry underground system (based on Gravitiricity technology). The 3.5-year approximation relates to a wet system (based on Heindl Energy technology): Schmidt O (2018) Levelized cost of storage: Gravity storage. Imperial College London Consultants. <https://heindl-energy.com/wp-content/uploads/2018/10/LCOS_GravityStorage-II-Okt-2018.pdf> (accessed 8 November 2022).

149 Kebede A, Kalogiannis T, Mierlo J, Berecibar M (2022) A comprehensive review of stationary energy storage devices for large scale renewable energy sources grid integration. Renewable and Sustainable Energy Reviews 159, 112213.

150 Patonia A, Poudineh R (2020) Ammonia as a storage solution for future decarbonised energy systems. Oxford Institute for Energy Studies. <https://www.oxfordenergy.org/publications/ammonia-as-a-storage-solution-for-future-decarbonized-energy-systems/> (accessed 24 October 2022).

151 Nagashima M (2020) Japan's hydrogen society ambition: 2020 status and perspectives. IFRI. <https://www.ifri.org/sites/default/files/atoms/files/nagashima_japan_hydrogen_2020.pdf> (accessed 23 November 2022).

LCOS analysis

To support technology cost discussion (see Section 3.1 for LCOS discussion), demand modelling results from Part I have been used to identify electrical storage applications (see Appendix C for assumptions and approach). Specifically, these results have been used to identify specific storage durations and annual cycles (see Table 7). As discussed earlier, the short-duration application example considers a storage technology with a 2-hour duration that is used 394 times over the course of a year.

To illustrate the differences in results driven by annual cycle assumptions, the medium duration (8-hour duration) application considers a 230 annual cycle assumption (consistent with modelled utilisation rates for lithium-ion batteries at this duration) and a 285 annual cycle assumption (consistent with modelled utilisation rates for pumped hydro at this duration).

The requirement for seasonal storage has been excluded from the LCOS analysis. Although important, the role of seasonal storage on the grid requires further analysis and the limited number of existing projects make cost estimation across technologies difficult. While the NEM sees an uptake of seasonal storage driven by the introduction of Snowy Hydro 2.0, which can provide approximately 1 week of storage, there are no planned projects for seasonal storage using other technologies.

As discussed earlier, it is important to note that although related to the demand modelling results, the exact durations and cycles should be viewed as examples only because there are various factors that may change the applications (e.g. different weather patterns).

Table 7: LCOS application examples for major grids

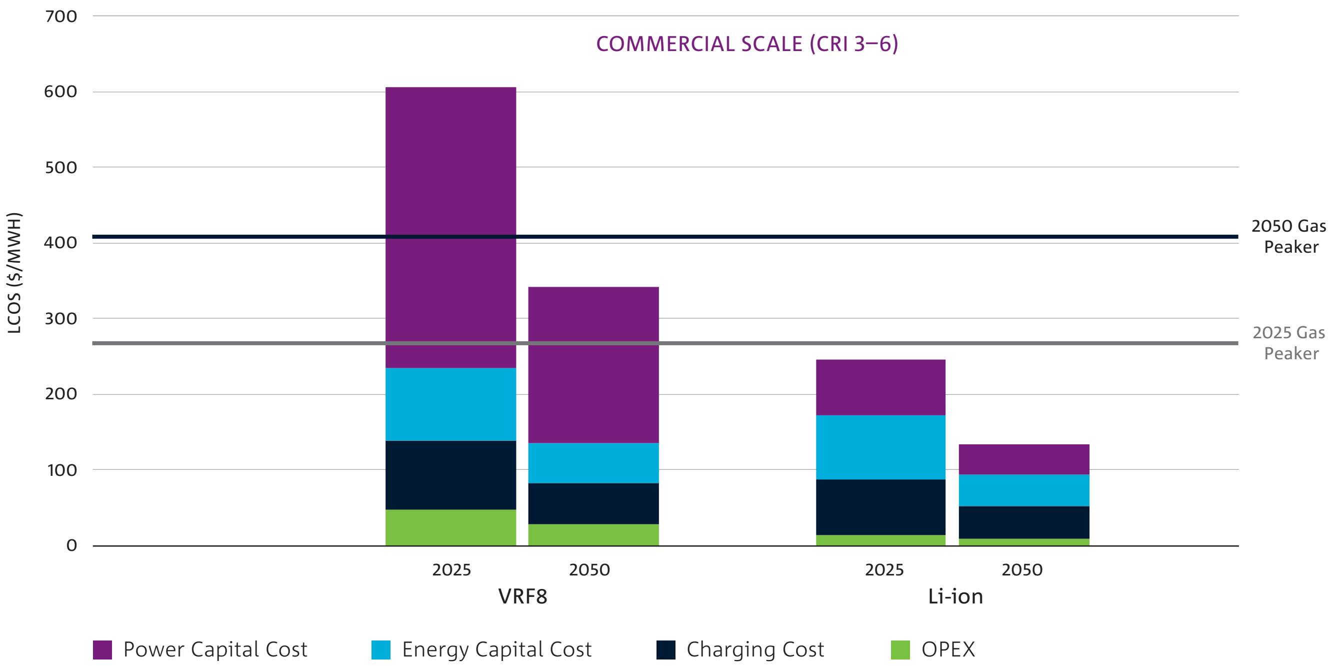
APPLICATION EXAMPLE	DURATION (HOURS)	CYCLES (PER YEAR)
Major Grids – Short duration	2	394
Major Grids – Medium duration	8	230; 285
Major Grids – Long intraday	24	117
Major Grids – Long multiday	48	68

Terminology: LCOS, levelised cost of storage.

Short-duration LCOS

For the specific application analysed, Li-ion batteries were estimated to have a lower LCOS when compared with VRFB in the near and long term. Both technologies were estimated to be competitive with a gas peaker in 2050.

Figure 20: LCOS results, short-duration storage (2-hour storage duration, 394 annual cycles)

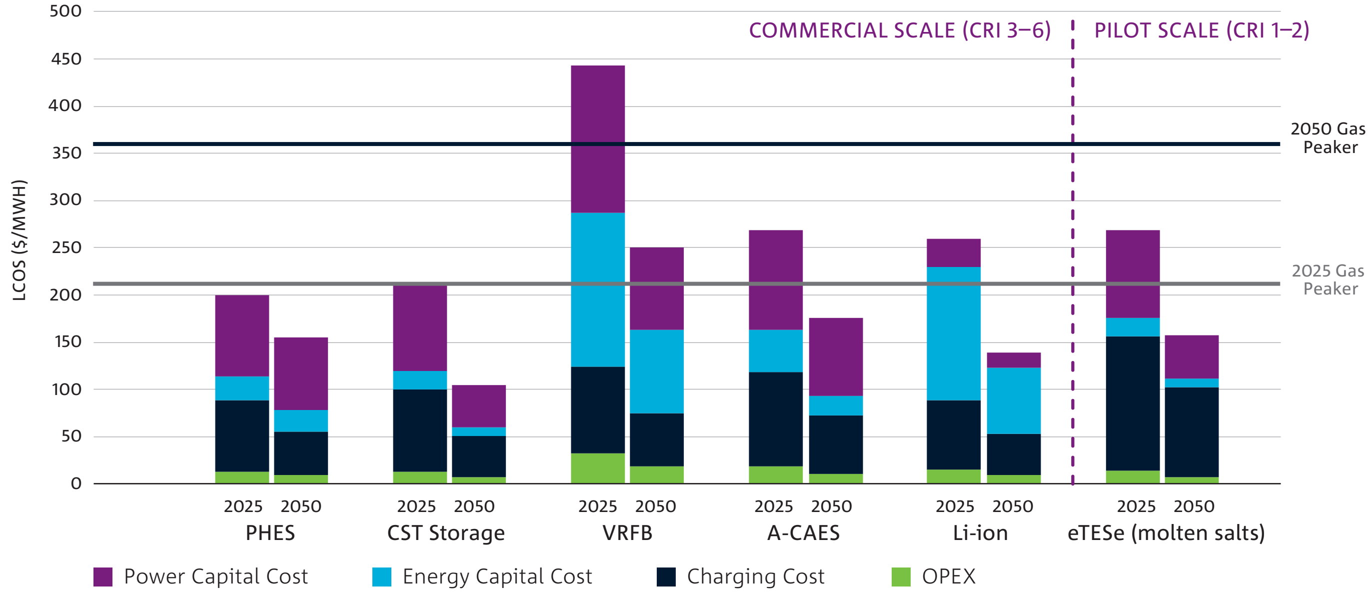


Notes: See Section 3.1 for further discussion on interpreting LCOS results. For assumptions and approach, see Appendix C. Terminology: CRI, commercial readiness index in major grid applications; LCOS, levelised cost of storage; OPEX, operating expenses; Li-ion, lithium ion batteries; VRFB, vanadium redox flow batteries.

Medium-duration LCOS

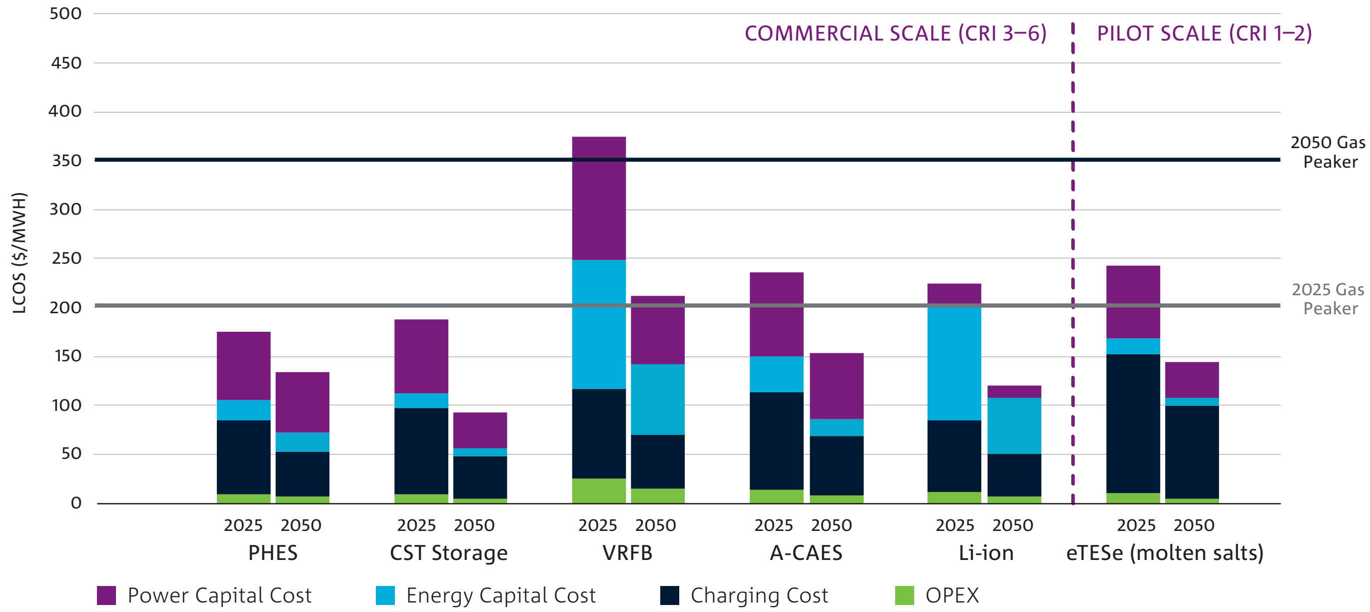
For the specific 8-hour (230 and 285 annual cycle) storage duration cases, PHES was estimated to have the lowest cost in the near term. In the long term, CST storage was estimated to have the lowest cost for the cases analysed.[152] All technologies were estimated to be competitive with gas peakers in the long term.

Figure 21: LCOS results, medium-duration storage (8-hour storage duration, 230 annual cycles)



Notes: See Section 3.1 for further discussion on interpreting LCOS results. For assumptions and approach, see Appendix C. Terminology: A-CAES, adiabatic compressed air energy storage; CRI, commercial readiness index in major grid applications; CST Storage, concentrated solar thermal storage component; eTESe, electricity to thermal storage to electricity; LCOS, levelised cost of storage; OPEX, operating expenses; VRFB, vanadium redox flow battery; PHES, pumped hydro energy storage.

Figure 22: LCOS results, medium-duration storage (8-hour storage duration, 285 annual cycles)



Notes: See Section 3.1 for further discussion on interpreting LCOS results. For assumptions and approach, see Appendix C. Terminology: A-CAES, adiabatic compressed air energy storage; CRI, commercial readiness index in major grid applications; CST Storage, concentrated solar thermal storage component; eTESe, electricity to thermal storage to electricity; LCOS, levelised cost of storage; OPEX, operating expenses; VRFB, vanadium redox flow battery; PHES, pumped hydro energy storage.

152 However, its applicability is limited to applications where the energy is supplied as solar generated heat whereas the other technologies can all accept electricity as the charging input. On the other hand, it could also provide advantages if there is a local demand for heat as well as electricity.

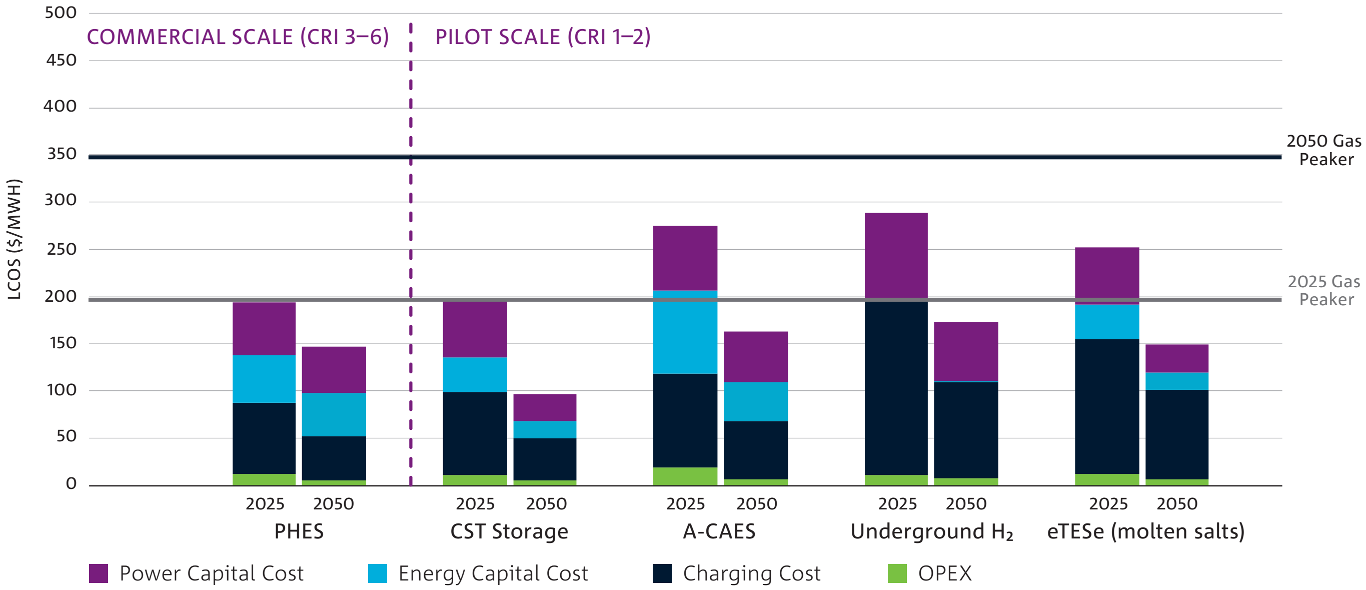
Intraday LCOS

For the specific 24-hour (117 annual cycle) storage duration case, PHES and CST storage were estimated to have the lowest costs in the near term. In the long term, CST storage was estimated to have the lowest cost for the case analysed.[153] All technologies were estimated to be competitive with gas peakers in the long term.

Multiday LCOS

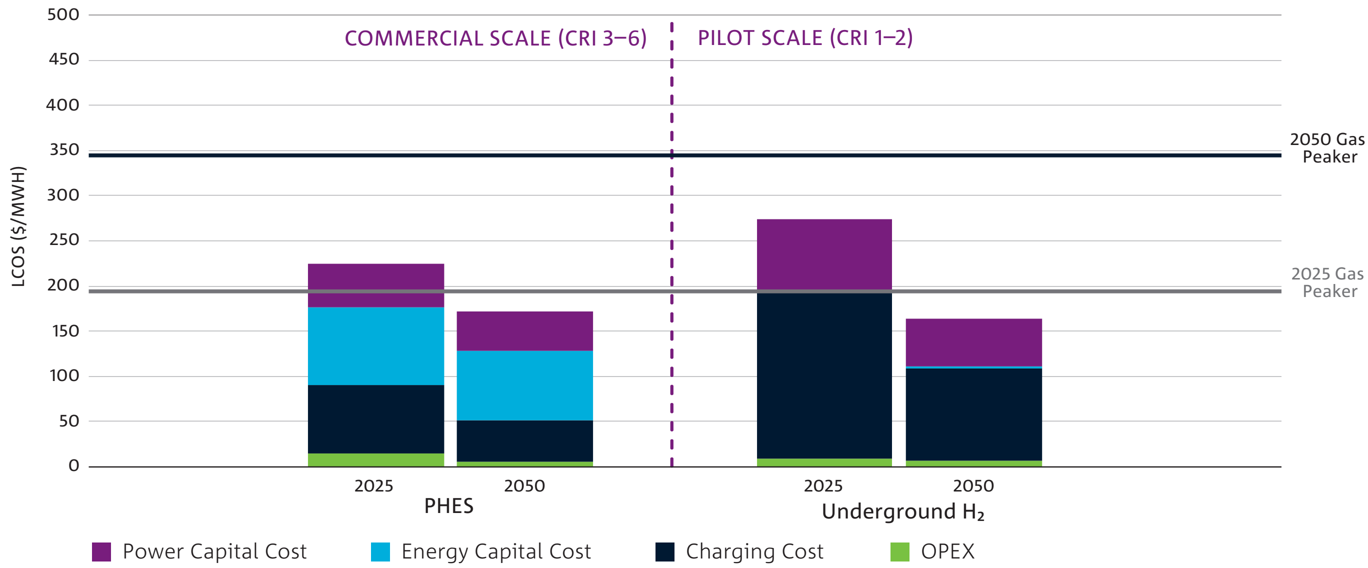
For the specific 48-hour (68 annual cycle) storage duration case, PHES was estimated to have the lowest cost in the near term. In the long term, underground hydrogen storage was estimated to have a slightly lower cost than PHES for the cases analysed. Both technologies were estimated to be competitive with gas peakers in the long term.

Figure 23: LCOS results, long intraday storage (24-hour storage duration, 117 annual cycles)



Notes: See Section 3.1 for further discussion on interpreting LCOS results. For assumptions and approach, see Appendix C. Terminology: A-CAES, adiabatic compressed air energy storage; CRI, commercial readiness index in major grid applications; CST Storage, concentrated solar thermal storage component; eTESe, electricity to thermal storage to electricity; H_2, hydrogen; LCOS, levelised cost of storage; OPEX, operating expenses; PHES, pumped hydro energy storage.

Figure 24: LCOS results, long-multiday storage (48-hour storage duration, 68 annual cycles)



Notes: See Section 3.1 for further discussion on interpreting LCOS results. For assumptions and approach, see Appendix C. Terminology: CRI, commercial readiness index in major grid applications; H_2, hydrogen; LCOS, levelised cost of storage; OPEX, operating expenses; PHES, pumped hydro energy storage.

153 However, its applicability is limited to applications where the energy is supplied as solar generated heat whereas the other technologies can all accept electricity as the charging input. On the other hand, it could also provide advantages if there is a local demand for heat as well as electricity.

3.3 Large-scale, isolated grids: Remote mining

For remote and off-grid mining sites, short-duration energy storage within a hybrid generation grid can provide significant emissions reductions in the near term and reduce existing levels of fossil fuel usage. However, eliminating emissions in remote mining will require long-duration storage technology options. While several options could potentially be commercially competitive with diesel, these are not widely demonstrated at scale across mining operations.

Miners recognise that sustainability, including acting responsibly and generating social value, is critical to business performance, and decarbonising operations is recognised as part of this solution. Emissions on mine sites come from various sources, including fuels for heavy-duty haulage, electricity for onsite operations (particularly for crushing and grinding) and heat generation for minerals processing. Further, as countries continue to accelerate their efforts to reduce emissions and adopt renewable energy technologies, there will be increased demand for critical minerals and metals, including storage technologies, creating an opportunity for the mining industry.[154]

	LARGE-SCALE, ISOLATED GRIDS: REMOTE MINING Electricity energy storage (of different durations) to support Australia's major and isolated grids
Electrochemical	✓
Mechanical	✓
Chemical	✓
Thermal	✓

✓ Technology options explored in section

154 Bruce et al. (2021) Critical energy minerals roadmap. CSIRO, Australia.

Although there are multiple pathways to decarbonise, there is a broad expectation that renewable energy and electrification will play major roles in decarbonisation across the mining industry.[155] This could include replacing diesel-powered equipment with electrically powered equipment, and displacing diesel- or gas-powered electricity generation with VRE.[156]

Energy storage will be key in supporting increasing levels of VRE and electrification, particularly for Australian mine sites that are remote and off-grid. Half of the Australian mines that process onsite are not connected to grid electricity, with the energy for beneficiation, including crushing and grinding, primarily consumed as electricity.[157] Currently, most of this electricity is generated from diesel or natural gas, and typically through a contract with an independent power producer. As this energy transitions to VRE, storage will be needed to manage intermittency and offset the longer-duration storage provided by fossil fuels.

The scale and type of storage deployed, as well as the timeline for VRE and electrification effort, will vary on a site-by-site basis. Typically, mining operations require a largely flat base load of electricity supplied consistently over a day to maintain operations. In an isolated grid, this load can vary in scale, ranging from tens to hundreds of megawatts depending on the operation. One stakeholder suggested that electrification could result in a 10- to 20-fold increase in a given site's electric load, requiring significantly more energy than what the power system was designed for. Further, some sites may have technical or operational constraints that can make it difficult for particular assets or processes to be electrified, such as loading and hauling activities that currently require fuels.

Role of energy storage

Energy storage technologies can play a broad role in supporting decarbonisation efforts in the mining sector. Electricity storage can improve reliability and power quality alongside increasing levels of electrification of mining operations and mining vehicles, and higher proportions of VRE. Thermal energy storage can support both process heat requirements related to beneficiation and metal production and power requirements. Finally, the storage of green hydrogen can help decarbonise heavy vehicles and provide long-duration power.

As stated earlier, sites that are not grid connected have a more complicated transition related to electrification and the use of VRE and storage. While this section focuses on remote mining, storage implications related to a grid-connected mine have been included (see Figure 25), and further information can be gleaned from the discussion of major grids (see Section 3.2).

Although simplified, the role of storage for remote mines is explored through the consideration of a hybrid and fully renewable grid. This is further explored through a site-specific case study (see Figure 26).

Hybrid mining grids

For remote and off-grid Australian mining sites, energy storage within a hybrid grid using VRE can provide an immediate and substantial step in decarbonisation.

Short-duration storage in particular will be required to manage power quality and help meet daytime loads. Without longer-duration storage investments, there would still be a requirement for fossil fuels to cover night-time loads in the short to medium term, leading to a partially decarbonised system.

155 CEFC and MRIWA (2022) Technology solutions for decarbonisation: Mining in a low-emissions economy. <https://www.cefc.com.au/media/omzlxjpl/cefc_mriwa_technology-solutions-for-decarbonisation.pdf> (accessed 24 October 2022).

156 Butler C, Maxwell R, Graham P, Hayward J (2021) Australian industry energy transitions initiative Phase 1 technical report. ClimateWorks Australia. <https://energytransitionsinitiative.org/wp-content/uploads/2021/06/Phase-1-Technical-Report-June-2021.pdf> (accessed 24 October 2022).

157 ARENA, SunSHIFT (2017) Renewable Energy in the Australian Mining Sector: White Paper. <https://arena.gov.au/assets/2017/11/renewable-energy-in-the-australian-mining-sector.pdf> (accessed 12 January 2023).

Depending on a site's requirements and renewable energy resources, a hybrid grid system could result in significant levels of decarbonisation. For example, analysis of the Gold Fields Agnew Gold Mine highlighted this potential and forecast that a hybrid grid consisting of a wind and solar farm with a battery energy storage system could deliver an annual average of 54% renewable energy, with gas and diesel providing the remaining load. The analysis also found that, under favourable weather conditions, the hybrid grid was able to deliver over 85% of the site's power requirements.[158]

Fully renewable mining grids

Long-duration storage technologies will be critical to achieving greater emissions reductions and penetration of renewable generation. Although several systems are potentially competitive with diesel, these are not widely demonstrated at scale across mining operations (including sites with different load profiles, scales and environments).

A fully renewable grid may still use a short-duration energy storage system to manage power quality and will require a long-duration storage system to offset the energy load previously provided by fossil fuels.

The scale of energy required to cover the load provided by fossil fuels and the need for operational reliability and to minimise downtime has various implications for the storage system used, and its feasibility. For example, the long-duration storage system would be required to meet night-time energy loads, which, depending on the site, could require consideration of intraday to multiday storage (i.e. 12–48 hours). Further, the long-duration system would need to be large enough to cover the longest continuous period of time over which the fossil fuel would be used (i.e. in winter, when there is less solar output). It would also need sufficient time and renewable capacity to charge, and may require the VRE system to be oversized. Finally, the system would also need to increase alongside greater levels of electrification, as discussed earlier.

However, as stated earlier, there are a limited number of long intraday and multiday and seasonal storage technologies that have been demonstrated at scale and across a range of environments. This challenge has been recognised by the Electric Mine Consortium in Australia, which has recently launched an energy storage challenge and is seeking expressions of interest from providers to deliver long-duration energy storage systems at nominated sites.[159]

Although beyond the scope of this report, this challenge related to long-duration storage highlights the importance of continued energy efficiency and process change investments, particularly to create options that reduce or defer the required load. For example, to reduce storage requirements, a greenfield mine could examine whether a flexible load profile could be created to maximise production during high-VRE periods. This may include the use of distributed and high-efficiency comminution equipment. The extent to which flexible processing and energy storage are used will depend on the implications on production output. Although not as straightforward in a brownfield operation, there may be similar opportunities to introduce process change depending on mine life and the decarbonisation strategy.

158 Koerting J (2022) Gold Fields Agnew Gold Mine hybrid micro-grid project. <https://arena.gov.au/assets/2022/03/gold-fields-agnew-gold-mine-final-report.pdf> (accessed 24 October 2022).

159 Electric Mine Consortium (n.d.) The EMC's energy storage challenge – expression of interest. <https://www.electricmine.com/projects/the-emcs-energy-storage-challenge/> (accessed 12 October 2022).

Figure 25: Storage considerations for grid-connected mines

For grid-connected mines, the decision to invest in storage or not will relate to the local grid's ability to support the projected increase in load from electrification activities. For grid-connected sites, it will be important to understand the implications of electrification. For example, for some sites, increasing levels of electrification may outpace the relevant power system's ability to support the increased energy load.

In parallel, these sites will need to work with local providers to understand the current and proposed future storage mix across the local grid and any transmission and distribution (T&D) infrastructure development plans underway, alongside the projected life of the mine. Sites with a short mine life may not be able get approval for the development or upgrade of transmission infrastructure. Once understood, operators will need to consider existing power contracts in place and green power purchase agreement options, as well as future electricity prices, local market sensitivities and risks, such as the impact of an outage on production. For some, this may result in investment in behind-the-meter storage (e.g. to take advantage of low-cost electricity during the day to help offset higher night-time energy costs).

Although not explored in this report, fringe-of-grid mines have challenges similar to remote mines because some can face high electricity costs and potential unreliability due to their location near the end of a grid network. It is also important to acknowledge that, with approval, it is possible for a remote mine to be grid connected if economic and technically feasible based on factors such as the proximity of the site to a major grid and available resources, as well as mine life. Further storage considerations can be found in the discussion of major grids (Section 3.2).

Deployment considerations

Storage deployment considerations vary on a site-by-site basis and play into a mining company's overall decarbonisation strategy, with energy storage technology being only one factor.

Although not exhaustive, this section builds on the considerations discussed in Section 3.1 to highlight specific storage deployment considerations related to remote mining.

- **Cost:** Base load electricity supply can be a large component of costs for some mines and will increase with greater levels of electrification. As such, storage-related costs will need careful consideration to ensure that the overall levelised cost of energy for a given mine is economic. The costs will be site specific. However, an example of storage costs for a specific site can be seen through the developed case study (see Figure 26). Deployment will need to consider system redundancy to support planned maintenance and avoid risk of interruptions.
- **Maturity:** Maintaining operations and minimising downtime is critical for the mining industry and will likely result in the preferencing of mature technologies (CRI 3 or above) that offer reliability and have been widely demonstrated at scale. However, given the difficulties and costs in providing reliable long-duration energy storage, some organisations (or the industry more broadly) may have the appetite and financing to demonstrate technologies in development and deployment stages (TRL 6–9/CRI 1–2) where there are clear gaps.
- **Economies of scale:** Given the opportunity to reduce overall costs with larger systems, some operations may choose to consider larger, less geographically flexible systems depending on the mine life and other site characteristics. A large storage asset may be economical where there are multiple end-users of storage in a given area.

- **Modularity and scalability:** In general, stakeholder feedback suggested that modular systems without geographical constraints will be preferred. One stakeholder suggested that the need for modularity may support future trends towards shorter-term energy contracts (<10 years). In addition, modularity may support future low-impact mining trends or modular mining of small, dispersed deposits. The ability to scale a storage system over time is expected to be valuable in helping to incrementally increase decarbonisation efforts. For example, this would allow an operator to increase levels of renewable deployments and electrification while incrementally stepping up the storage required.
- **Geographical and site characteristics:** The scale, remoteness and mixed types of energy used in the mining industry results in unique geographical-, region- and site-specific storage considerations. It also gives rise to technology options not available in other settings, for example, technology subsystems that make use of underground mining caverns for storage or using mine closure projects in a region to create energy and storage potential.
- **Construction times:** It is assumed that construction time frames (and lead time for planning and approvals) will generally need to be short (3 years or less) to keep pace with expected VRE deployments and net zero ambitions. This assumption may also align with the often-cyclical nature of the mining industry and its investment horizons. However, sites with a long mine life or greenfield developments may be open to longer-term investments. This may also be the case in regions where there is a concentration of mining activity, such as the Pilbara, where investment could be shared between multiple users.
- **Safety and risk management:** Workforce and community safety is critical to mining operations. As such, storage technologies, even those that have been widely deployed in other industries, will undergo careful planning and evaluation to understand risks and how best to manage them. Technologies still under development may require additional piloting and data gathering in a way that does not impact safety and operations.
- **Social and environmental considerations:** Beyond decarbonisation objectives and safety considerations, the mining industry recognises the importance of social impact and will need to assess local community and environmental considerations related to their technology choices. This is particularly important for storage technologies that use large amounts of land or where the shift to renewables and storage will change workforce requirements and necessitate the creation of new jobs.

Technology options

The availability of large-scale and commercially proven long-duration storage technology options is expected to be a key challenge for remote mining. As such, this section focuses on technology options related to long-duration (intraday and multiday) energy storage. Further discussion related to the short-duration technologies can be found in Section 3.2 (major grids).

The technology options are not exhaustive and provide examples of the application of deployment considerations discussed above. A quantitative LCOS analysis has been conducted for a subset of these technologies to provide a point of comparison for the modelled assumptions. A summary is provided in Table 8.

More information on each of the technologies and the approach to LCOS modelling can be found in Sections 2.2, Section 3.1 and Appendices C and E.

Table 8: Summary of deployment considerations for long-duration storage technologies in mining applications

Consideration[160]	PHES	CST	A-CAES	Compressed hydrogen tanks	Underground hydrogen	eTESe	Gravity
Maturity (CRI) in mining applications	4	3	2	2	1–2	1–2	1–2
Economies of scale	Large opportunity to reduce cost per kilowatt for larger systems	Large opportunity to reduce cost per kilowatt for larger systems	Large opportunity to reduce cost per kilowatt for larger systems	Small opportunity to reduce cost per kilowatt for larger systems	Large opportunity to reduce cost per kilowatt for larger systems	Moderate opportunity to reduce cost per kilowatt (depends on system type)	Moderate to large (depends on system type)
Modularity and scalability	Not modular Limited incremental scalability	Modularity depends on system design Some systems have modular and scalable towers and arrays	Not modular Incrementally scalable (cavern expansions)	Modular Incrementally scalable (additional tanks)	Not modular Limited incremental scalability	Modularity depends on system design Thermal media can be modular and scalable	Not modular Limited incremental scalability (depends on system design)
Geographical and site characteristics	Topography requirements Water requirements Large footprint	Solar resources Larger footprint for larger-scale capacities (including solar array)	Geological requirements Moderate above-ground footprint	Flexible deployment Moderate footprint for larger-scale capacities	Geological requirements Moderate above-ground footprint	Flexibly deployed Moderate footprint	Geographical and footprint requirements depend on system type
Construction times	3–7 years	<2 years	2.5–3.5 years	1 year	1–5 years	Insufficient data	1–3.5 years
Use of critical materials[161]	Low	Moderate – (depends on alloy type)	Low	Low – depends on composite materials supply chain	Low	Low	Low

Pumped hydro energy storage

Although PHES deployments are generally commercially available, smaller-scale systems are at the supported commercial deployment stage (CRI 4). However, geological constraints and long development times may limit the use of PHES in mining. Depending on the region, there may be opportunities for the mining industry to consider PHES developments alongside mine closure and reuse activity.

For example, the Kidston Pumped Hydro Storage Project in Queensland takes advantage of two existing mining pits.[162] Although there is potential, further investigation is required to determine the cost competitiveness of small-scale systems on a site-by-site basis.

160 Explanation of the criteria can be found in Deployment Considerations in Section 3.1; References can be found in Appendix E.

161 A supply chain analysis for each technology was not conducted; Geoscience Australia (n.d.) Overview of critical minerals. <https://www.ga.gov.au/scientific-topics/minerals/critical-minerals#heading-2> (accessed 23 November 2022).

162 Genex (n.d.) 250MW Kidston pumped storage hydro project. <https://genexpower.com.au/250mw-kidston-pumped-storage-hydro-project/> (accessed 24 October 2022).

Concentrated solar thermal plus storage

CST combined with thermal storage can be used in various geographical locations. Although the storage system is scalable on its own, the overall CST technology, including its mirrored solar fields and power block, does not scale well to systems below approximately 20 MW in size. CST could have additional benefits by providing firming alongside higher VRE deployments and supporting thermal requirements related to onsite processing. Small scale, high temperature CST systems with molten salt storage is undergoing commercial-scale demonstrations (CRI 3) and can be used in remote locations.[163] Rio Tinto and Heliogen plan to deploy CST with molten salts at a borates mine in California.[164]

Although molten salts are the most commercially mature thermal storage deployed with CST, there are several other media that can be considered. Other media that can be used in CST are at pilot scale and include concrete and packed beds (e.g. 4-MW Airlight Energy CST plant in Morocco), particle systems (e.g. CSIRO's Newcastle facility), MGAs and graphite.

Although the scope of this roadmap is focused on the storage media discussed above, alternative CST systems that use hot and cold water are also being demonstrated. For example, RayGen is demonstrating grid-scale storage in its Carwarp project, Victoria, which will include 17 hours of storage (3 MW/50 MWh),[165] and completed a smaller demonstration for an agribusiness in regional Victoria.[166]

Compressed hydrogen tanks

Compressed hydrogen in tanks can be deployed quickly, is scalable and is involved in pilot-scale demonstrations (CRI 2). The case for using hydrogen for a mining operation could be strengthened if hydrogen (or a low-emission hydrogen derivative) was produced and available onsite for other activities, such as haulage. In this case, the capital investment could be spread across power and transport needs. Further, there could be additional benefits if an operation is near a proposed hydrogen hub or pipeline. For example, if hydrogen is delivered to the site via pipeline, this could reduce onsite energy storage requirements.

Underground hydrogen

Underground hydrogen (CRI 1–4) can supply long-duration and seasonal storage for mining, but its applicability will depend on the geological characteristics of the site, such as the availability of suitable salt caverns, depleted fields and aquifers. Storage of hydrogen in large quantities may be more cost-effective if there are multiple end users, such as multiple mining and industrial operations in the area, or as part of a hydrogen hub. There could be benefits if a given site was using hydrogen (or a derivative) to meet site haulage requirements or if the site was close to a pipeline.

Compressed air

Current large A-CAES systems are based on underground storage, which is not modular, but caverns can be scaled with excavation techniques to increase storage capacity. A-CAES has not been deployed in a mining context (CRI 2), but can be considered for long-duration (intraday and multiday) storage in mining because these systems can use mine caverns and depleted gas wells, thereby reducing construction time frames. A current example includes Hydrostor's plans to construct a 200-MW A-CAES plant at the former Broken Hill mine, NSW, beginning in early to mid-2023.[167] There have also been several studies that have considered A-CAES using repurposed mines and hard rock caverns (taking advantage of nearby electricity generation infrastructure); however, not all sites are suitable.[168]

163 POLYPHEM (2022) Objectives < https://www.polyphem-project.eu/about-us/#objective>l POLYPHEM (2022) > (accessed 22 November 2022; Ferriere A (2022) The project POLYPHEM: objectives, challenges and results. Presentation. Available < https://www.polyphem-project.eu/wp-content/uploads/2022/09/1_POLYPHEM_AF_compressed.pdf> (accessed 22 November 2022)

164 Rio Tinto (2021) Rio Tinto selects Heliogen's breakthrough solar technology to provide carbon-free energy to Boron mine <https://www.riotinto.com/en/news/releases/2021/Rio-Tinto-selects-Heliogens-breakthrough-solar-technology-to-provide-carbon-free-energy-to-Boron-mine> (accessed 11 November 2022)

165 RayGen (2022) RayGen power plant – Carwarp. <https://raygen.com/projects/raygen-power-plant> (accessed 22 November 2022).

166 RayGen (2018) RayGen's PV Ultra: Expanding the global solar market beyond daylight power. <https://arena.gov.au/assets/2018/08/raygen-pv-ultra-expanding-global-solar-market-beyond-daylight-power.pdf> (accessed 23 November 2022).

167 Hon Chris Bowen MP (2022) $45 million for underground renewable energy storage in Broken Hill. Media releases. https://minister.dcceew.gov.au/bowen/media-releases/45-million-underground-renewable-energy-storage-broken-hill (accessed 11 December 2022); Marshall C (2022) Broken Hill's compressed-air energy storage project chosen as best back-up power supply option. ABC Broken Hill. <https://www.abc.net.au/news/2022-05-27/transgrid-hydrostor-broken-hill-back-up-power-option/101103082> (accessed 10 June 2022); Transgrid (2022) Preferred option for Broken Hill back up electricity supply identified. <https://www.transgrid.com.au/media-publications/news-articles/preferred-option-for-broken-hill-back-up-electricity-supply-identified> (accessed 10 June 2022).

168 Clennell MB, Czapla J, Green C, Wilkins A, Sheldon H, Cousins A, Lacey J, White C, Ahmed S, Irons M (2022) Underground energy storage. CSIRO, Australia. [Unpublished]

Thermal energy storage systems

Standalone eTESe with a VRE input source can be used with a variety of thermal storage media. Molten salt systems are at pilot-scale demonstrations (CRI 1–2), and can be used to provide medium-duration and intraday storage. Although molten salts are the most mature form of thermal storage to date, current commercial molten salt systems have limited modularity and incremental scalability (i.e. two-tank systems); however, there is potential for smaller-scale modular designs to be developed. Current systems require maintaining temperatures above melting point or using antifreeze systems, and require regular maintenance.

There are several other thermal media that benefit from modularity and scalability, which can be helpful given the variety of system sizes required at different mining sites, and for de-risking projects. Silicon can be used in eTESe systems to provide firming services to a grid (TRL 4–5/CRI 1); for example 1414 Degree's TESS-GRID technology could be used to provide energy services to isolated or fringe-of-grid mining areas.[169] Other media that could be considered for grid-scale eTESe but have not yet been demonstrated at large scale include concrete and packed bed systems, graphite and MGAs.

Gravity

Gravity storage has garnered interest in the mining industry, particularly in relation to BHP's investment in the gravity storage company Energy Vault.[170] There are also several startups promoting different above- and underground gravity storage systems, including the use of potential energy from the weight of unloaded trains. As discussed earlier, gravity storage is still being demonstrated at pilot scales (CRI 1–2).

Alternative technologies

There are several other technologies of varying maturity levels that can be applicable for long duration storage on large isolated grids for mining including hydrogen derivatives and bioenergy. Mine sites may continue to depend on small portions of fossil fuels for backup power in the short and medium term, and make use of offsets. Although not considered in this roadmap, biofuels could be used as a low emissions alternative to diesel generation in off-grid environments.[171] However, supply of biofuels or biogas is a key consideration given the scale of operations. Hydrogen derivatives can also be used to replace diesel peakers; for example, methanol can be used directly by a turbine engine to generate electricity with current technology. Ammonia can be cost-effectively transported and stored using current technologies, but the combustion of ammonia for power applications is under development to overcome challenges such as nitrogen oxides (NO_x) emissions.[172]

Technologies to enable the integration and optimisation of multiple storage systems could help manage system needs and intermittency, cover short- medium- and long-duration power needs and provide additional reliability. Although beyond the scope of this report, technologies to enable demand-side flexibility can also be considered. This includes continued energy efficiency and process change investments that can reduce or defer required loads, such as high-efficiency comminution equipment and flexible site operations that maximise production during high-VRE periods.

169 1414 Degrees (2019) 1414 Degrees acquiring Aurora Project near Port Augusta. <https://1414degrees.com.au/acquiring-aurora-project/> (accessed 22 November 2022).

170 BHP (n.d.) BHP ventures. <https://www.bhp.com/about/our-businesses/ventures> (accessed 24 October 2022).

171 ENEA Australia, Deloitte Financial Advisory (2021) Australia's bioenergy roadmap. <https://arena.gov.au/assets/2021/11/australia-bioenergy-roadmap-report.pdf> (accessed 24 October 2022).

172 Erdemir D, Dincer I (2020) A perspective on the use of ammonia as a clean fuel: Challenges and solutions. International Journal of Energy Research 45, 4827–4834.

Figure 26: Remote mining case study

The role of storage has been explored through the case of an off-grid mine located in remote north-western WA that aims to shift its electrical load from being provided via diesel power generation to a high penetration of renewables (solar and wind) with storage.

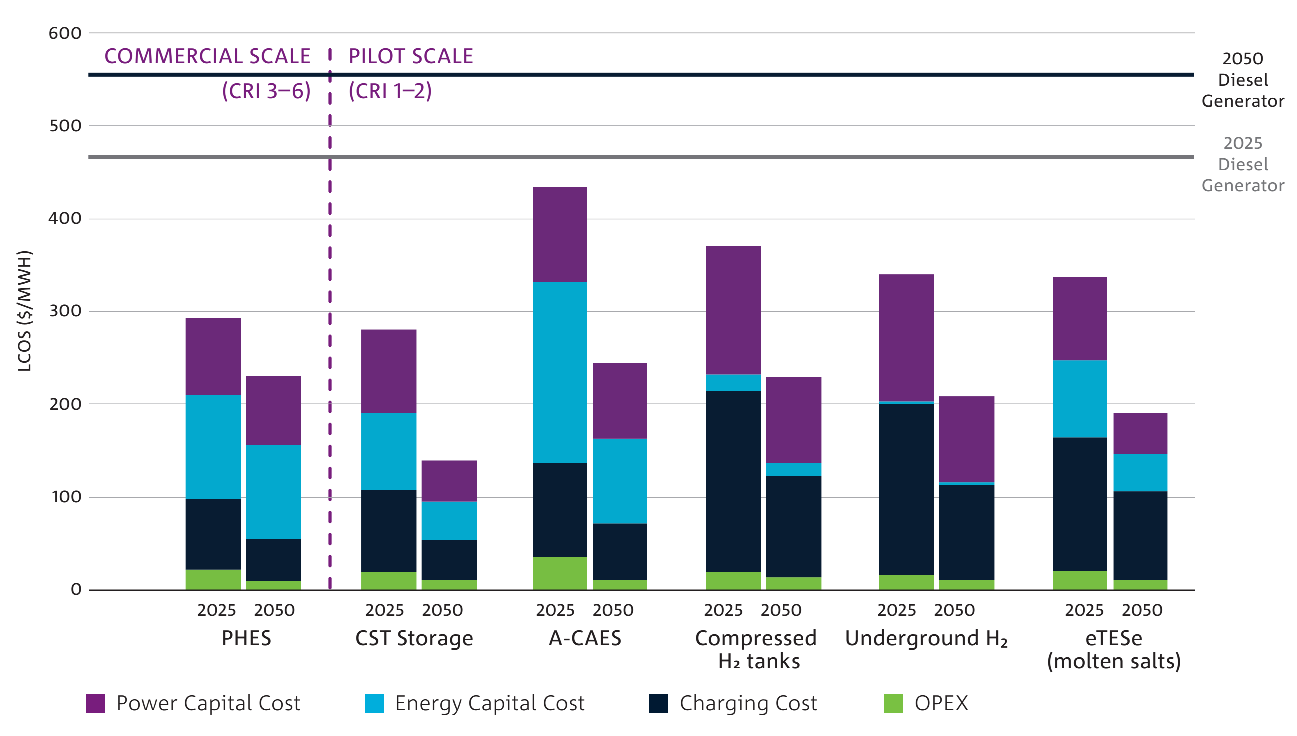
For simplicity, the case uses VRE to largely offset daytime load requirements and considers the potential for energy storage to meet the remaining base load requirements currently being fulfilled by diesel. The site has a peak and largely flat load of 47.7 MW (average load 44.46 MW), average daily energy usage of 1,067 MWh per day and a 19.3% day-to-day variability in its load. Approximately 200 MW of PV was assumed to be installed, accounting for approximately 42% of the site's load, with the remaining 58% met by diesel.

Two types of storage requirements were identified for the specific remote mining case analysed: a short-duration energy storage system to support the VRE deployment and a long-duration storage system to cover the diesel system.

The short-duration energy storage system identified required a fast response time to manage renewable energy intermittency. On average, storage was required for a 30-minute duration and had the equivalent of 102 full discharge cycles per year. A long-term energy storage system to cover the energy provided via diesel would require an energy storage capacity of 3.3 GWh and 93 MW, or 93 MW with a total duration of 36 hours and with 52 full discharges per year (or once per week, on average).

CST Storage was estimated to be the least cost system in the near and long term. All technologies considered are projected to be competitive with diesel in the near and long term.

LCOS results, remote mining case study supporting 200MW solar PV (36-hour storage duration, 52 annual cycles)



Notes: See Section 3.1 for further discussion on interpreting LCOS results. For case study background and approach see Appendix D and for further information on LCOS analysis see Appendix C. Terminology: A-CAES, adiabatic compressed air energy storage; CRI, commercial readiness index in mining application considered; eTESe, electricity to thermal storage to electricity; LCOS, levelised cost of storage; OPEX, operating expenses; PHES, pumped hydro energy storage.

3.4 Isolated microgrids: Remote communities

Energy storage paired with renewables has the potential to increase access to electricity supply for remote communities, support high levels of decarbonisation and reduce electricity costs. However, the ability to achieve these outcomes across diverse community types and regions will require community engagement. Storage systems will need to be cost-effective in terms of upfront investment and ongoing costs, and easy to maintain. Eliminating emissions will require storage systems capable of maintaining power quality and providing reliable energy for days or weeks.

As a result of Australia's geographically distributed population, there are numerous isolated grid networks in operation to service regional and remote electricity demand. For example, in WA, Horizon Power provides services to 34 remote and isolated microgrids and their communities.[173] In Queensland, Ergon Energy Network provides generation and network services for 33 isolated microgrid systems across 39 communities.[174]

Supply of electricity to remote, small communities is serviced by isolated microgrids, classified as those with scale capacities of between 200 kW and 2 MW.[175] For example, Sandstone in WA has a population of around 89 people and is supported by a microgrid with an installed generation capacity of 456 kW.[176]

	ISOLATED MICROGRIDS: REMOTE COMMUNITIES Electricity energy storage (of different durations) to support Australia's major and isolated grids
Electrochemical	✓
Mechanical	✓
Chemical	✓
Thermal	✓

✓ Technology options explored in section

173 Horizon Power (2021). Connecting vibrant communities – annual report 2020/21. <https://web.horizonpower.com.au/media/7092/part-1_horizonpower_annual-report_2020_2021.pdf> (accessed 12 October 2022).

174 Ergon Energy (n.d.) Decarbonising isolated communities. <https://www.ergon.com.au/network/network-management/network-infrastructure/isolated-and-remote-power-stations/decarbonising-isolated-communities> (accessed 12 October 2022).

175 Phillips R, Rose B, Porter I (2018) Inquiry into microgrids and associated technologies in WA. Sustainable Energy Now Inc. <https://www.parliament.wa.gov.au/Parliament/commit.nsf/luInquiryPublicSubmissions/0D74033E005825704825827900 2403B8/$file/20180418%20-%20MAT%20-%20Sub%20No.%2027%20-%20Sustainable%20Energy%20Now.pdf> (accessed 23 November 2022).

176 Australian Bureau of Statistics (2016) Sandstone: 2016 Census all persons QuickStats. <https://www.abs.gov.au/census/find-census-data/quickstats/2016/SSC51315> (accessed 24 June 2022).

Energy storage has the potential to help address various challenges involved in the supply of electricity to these remote areas, including:

- **Increasing access:** In remote areas, electricity is important for thermal comfort and safety in extreme weather; however, access can be challenging. This is particularly true for First Nations communities that are off-grid and require prepayments for electricity access.[177] Numerous factors can increase the risk of temperature-related harm faced by First Nations communities when disconnected from electricity.[178] Community-owned renewable generation and storage are seen as approaches to address outages and improve access to power in extreme weather. This is one focus area of the First Nations Clean Energy Network, which was established to ensure the cost, reliability and economic benefits of the renewable energy transition are shared with First Nations people.[179]
- **Supporting decarbonisation:** Numerous remote communities are reliant on diesel generation for electricity supply. Storage can help reduce this reliance on diesel by supporting integration and optimising the use of power generated from renewable energy sources.[180]
- **Reducing costs:** It can be more expensive to supply electricity to remote areas. For example, there can be high fuel, transport and maintenance costs associated with the use of diesel generators.[181] Renewable energy alternatives and storage are becoming an increasingly cost-competitive option for new power supplies.

Although energy storage can play a key role in improving access to electricity in remote areas, the storage system required and its potential to achieve the desired outcomes will vary across community types. It will depend heavily on the local energy resources available, as well as careful evaluation of deployment considerations and technology options (discussed later).

Role of energy storage

To help understand the role of energy storage in remote communities, a hybrid and fully renewable microgrid has been considered. This is supported by a case study to explore storage needs across two sites with different energy resources (see Figure 27).

Hybrid microgrids

The use of storage in a hybrid microgrid with renewables can reduce a community's reliance on diesel and help achieve high levels of decarbonisation. In the case of remote communities, these hybrid microgrids would typically consist of a renewable energy system coupled with diesel-fuelled generation, with storage playing a key role in helping to maintain power quality. The level of decarbonisation will be heavily influenced by community size and local energy resources. For example, for the two sites analysed in the case study, a hybrid microgrid was found to cover 50–80% of the sites' electrical load (Figure 27).

Fully renewable microgrids

Achieving a fully renewable microgrid can be challenging for some communities and will require energy storage technologies that can completely offset the role of diesel by maintaining power quality and providing reliable energy for days or even weeks. For example, a fully renewable microgrid that uses only renewable energy resources to generate electricity could use short-duration storage to smooth VRE fluctuations and power quality issues, and longer-duration storage to provide energy overnight and manage periods that alter energy loads. These altered energy loads could occur during a heatwave or as a result of extended weather periods that affect renewable generation from solar or wind.

177 Clean Energy Regulator (2021) Solar power for remote Indigenous communities. <https://www.cleanenergyregulator.gov.au/Infohub/case-studies/Pages/ret-case-studies/Solar-power-for-remote-Indigenous-communities.aspx> (accessed 16 September 2022).

178 Logden T, Quilty S, Riley B, White LV, Klerck M, Davis VN, Jupurrurla NF (2021) Temperature extremes exacerbate energy insecurity for Indigenous communities in remote Australia. Nature Energy 7, 43–54.

179 First Nations Clean Energy Network (n.d.) What we stand for. <https://www.firstnationscleanenergy.org.au/what_we_stand_for> (accessed 2 September 2022).

180 ARENA (n.d.) $50 million to ramp up microgrids in regional Australia. <https://arena.gov.au/news/50-million-to-ramp-up-microgrids-in-regional-australia/> (accessed 2 September 2022).

181 ARENA (n.d.) Off grid. <https://arena.gov.au/renewable-energy/off-grid/> (accessed 30 August 2022).

The scale of the long-duration storage challenge and the depth of storage required are highly variable depending on the community and are heavily influenced by the local energy resources available. For example, both sites analysed in the case study required diesel for long periods. It was found that offsetting diesel use would require a long-duration storage technology capable of providing 48 and 163 hours of storage for the two sites considered (Figure 27). These types of storage durations create a gap, or risk, for some remote communities interested in fully decarbonising. However, as discussed later, there are options, such as considering the use of short- and/or medium-duration storage with biodiesel, to achieve a fully renewable system.

Deployment considerations

Technology deployment considerations for remote microgrids are highly varied given the diversity of communities across Australia. Although not exhaustive, this section builds on the considerations discussed in Section 3.1 to highlight specific storage deployment considerations related to remote communities.

- **Cost:** Whole-of-system expenses are important factors to consider in remote communities. In particular, an understanding of operating costs, including inputs, maintenance cycles and support requirements, is extremely important. Resilience (see Serviceability and maintenance) could add additional costs that are unique to remote communities.
- **Maturity:** Remote communities will generally require mature technologies (CRI 3 or above) with a known track record of deployment and well-understood capital and operating costs. Given the varied nature of these communities, there is an opportunity for utility companies to innovate. For example, some power providers and trialling technologies in development and demonstration stages (TRL 6–9/CRI 1–2) in small-scale community contexts. However, consideration should also be given to potential challenges of servicing and maintaining technologies that are less mature in a remote setting (see Serviceability and maintenance).
- **Economies of scale, modularity and scalability:** There are limited opportunities for storage technologies to achieve economies of scale in remote communities due to their small-scale energy demand. As such, technologies that are more modular and incrementally scalable, with low CAPEX, would be beneficial. Modularity may support serviceability (discussed later) and the management and delivery of replacement units. Further, some level of portable storage may be of interest to communities to provide power needs in an emergency, such as an extreme weather event.
- **Geographical and site characteristics:** Remote areas of Australia can face particularly extreme weather conditions, and this can limit the effectiveness of certain storage technologies. In terms of temperatures, some parts of Australia may require storage systems that can operate effectively in temperatures above 50°C, requiring cooling, which can impact round-trip efficiency. Some communities are based in tropical climates, which could create technical challenges related to humidity. In these environments, there may also be a need to manage flora or fauna (e.g. geckos, frogs and snakes) ingress, creating system protection needs and the development of effective management approaches.

- **Serviceability and maintenance:** Microgrids located in remote areas may have reduced access to maintenance and emergency support services. Stakeholder feedback suggested that technologies are assessed by their serviceability. This includes considering local training and employment opportunities, the local presence of a technology vendor or a key agent and whether the vendor has integration experience and/or a relationship with a local deployment partner. Given this, it may be the case that a few standard types of systems become common solution sets for communities across Australia.

  Given the difficulty of accessing remote communities, it is important to plan and design for early life failures. Compared with diesel generator sets, less demonstrated storage technologies may experience early life failures for various reasons; for example, failures due to their maturity, their limited exposure to different environmental conditions (discussed previously) or to the way they were installed and integrated. Given this, it is important for a remote community to have additional storage units available (e.g. an extra unit connected and available in case there is an issue or for when there is planned maintenance, as well as an additional unit in storage in case there is a critical failure). This adds to the cost considerations for a given community. The community would also need to have sufficient spare parts to avoid a technician having to make multiple trips.

- **Safety and risk management:** There is a low threshold for potential safety risks and hazards to surrounding communities and the environment. For example, a battery fire in a remote community could be extremely difficult to resolve because some communities may not have available fire services or the local skills to manage an incident. Similarly, some communities could have constraints on water access, posing additional challenges. Understanding existing deployments, either in Australia or overseas, can help better identify and manage potential risks. This includes considering risks that could be introduced under different weather-related events, such as bushfires or floods.

- **Social and environmental considerations:** In addition to safety, the direct and indirect social impacts of storage technologies will be important for technology selection. Technology selection may be influenced through engagement of communities in identifying needs and co-developing solutions, and identifying opportunities for job creation. Consideration of various factors, including noise, heat, water and land use, will also be important in technology selection. Although beyond the scope of this report, it is important to understand the direct and indirect services that an existing emissions-intensive solution may be providing and the flow-on effects of removing a diesel generator. For example, in some communities, the services that bring in diesel are also used to bring in other items, including food, which can help drive down the costs of these items for the community.

Technology options

Long-duration energy storage systems that are cost-effective, easy to maintain, reliable and able to maintain power quality are expected to be a key challenge for remote communities. As such, this section focuses on technology options related to long-duration and seasonal energy storage. Further discussion related to the short-duration technologies can be found in Section 3.2 (major grids).

The technology options are not exhaustive and provide examples of the application of deployment considerations discussed previously. A summary is provided in Table 9. Further discussion is available through a case study and supporting LCOS analysis (see Figure 27).

More information on each of the technologies and the approach to LCOS modelling and case studies can be found in Sections 2.2, Section 3.1 and Appendices C, D and E.

Table 9: Summary of deployment considerations for long-duration storage technologies in remote microgrid applications

Consideration[182]	PHES	VRFB	Compressed hydrogen tanks	eTESe	Metal hydrides	Gravity
Maturity (CRI) in remote microgrid applications[183]	4	3–4	2	1–2	2	1
Modularity and scalability	Not modular Not incrementally scalable	Modular Incrementally scalable (tank capacity)	Modular Incrementally scalable (additional tanks)	Modularity depends on system design Thermal media can be modular and scalable	Modular Incrementally scalable (additional units)	Not modular Limited incremental scalability (depending on system type)
Geographical and site characteristics	Topography requirements Water requirements Large footprint	Flexibly deployed Smaller footprint for small-scale deployments Operating temperature from –15°C to 50°C	Flexible deployment Small footprint for small-scale capacities	Flexibly deployed Moderate footprint	Flexible deployment Small footprint	Geographical and footprint requirements depend on system type
Construction times	3–7 years	1–1.5 years	1 year	Insufficient data	Insufficient data	1–3.5 years, depending on system type and site
Use of critical materials[184]	Low	Moderate – vanadium	Low – depends on composite materials supply chain	Low	Low – depends on the type of hydride material used	Low

182 Explanation of the criteria can be found in Deployment Considerations in Section 3.1; References can be found in Appendix E.

183 Explanation of the criteria can be found in Deployment Considerations in Section 3.1; References can be found in Appendix E.

184 A supply chain analysis for each technology was not conducted; Geoscience Australia (n.d.) Overview of critical minerals. <https://www.ga.gov.au/scientific-topics/minerals/critical-minerals#heading-2> (accessed 23 November 2022).

Pumped hydro energy storage

Although associated with commercially competitive deployments at large scales worldwide and in Australia, there is potential to consider smaller-scale projects in the future if geographical, site and water requirements can be met. Although still large for many of Australia's remote communities, Western Power's Walpole Mini-Pumped Hydro project provides an example of a microgrid using small-scale PHES, with a maximum output of 1,500 kW helping to support a 400-kW average load in Walpole, WA.[185] The use of such a system could provide synchronous services, but would only be available to a subset of remote communities with the right geographical features.

Vanadium redox flow batteries

VRFB could be suitable for remote use given they are involved in supported commercial deployments (CRI 3–4). However, deployment may be limited to larger-scale remote applications to provide scale efficiencies and cover fixed system costs. VRFB feature a modular design, and the electrolyte solution can be repurposed for long-term use because it does not easily degrade upon discharge. VRFB systems may require air conditioning when there are sustained high temperatures to prevent the precipitation of the electrolyte over time (which lowers capacity), but they do not face thermal runaway issues.

Compressed hydrogen tanks

Hydrogen gas tanks are involved in pilot scale demonstrations (CRI 2) for power applications. They have minimal geographical requirements because the tanks are modular and can be interconnected to fit site requirements. Cost competitiveness may be limited due to round-trip energy efficiencies, compression infrastructure and safety and maintenance costs. Examples of demonstration projects being undertaken include the Denham Hydrogen Demonstration Plant, scheduled to be fully operational in 2024, which aims to replace diesel generation in a coastal town using a VRE and fuel cell system comprising compressed hydrogen storage tanks.[186] See alternative technologies for discussion of hydrogen derivatives.

Thermal energy storage systems

Standalone eTESe used with a VRE input source can be used with various thermal storage media. Molten salt thermal storage systems used with electricity input sources are at pilot-scale demonstrations (CRI 1–2). Although molten salt thermal storage systems are used in large-scale (>50-MW) systems, smaller systems could, in principle, be built (but at a higher unit cost). Advanced power cycles, such as supercritical CO_2 or Stirling cycles, may allow smaller systems to be built in the future. The Swedish company Azelio was identified as one example with systems (using recycled alumina as the storage medium) targeting projects as low as 500 kW and the aim of having 10 projects of different scales ranging from 0.5 to 5 MW delivered by 2023.[187]

There are several other thermal media that benefit from modularity and scalability, including silicon, graphite and MGAs. Graphite eTES systems have been demonstrated in a hybrid solar PV power plant (CRI 1–2) in regional NSW. MGA systems are undergoing RD&D (CRI 1), as well as a pilot demonstration of 5 MWh/500 kW.[188]

Metal hydrides

Metal hydrides are undergoing pilot-scale demonstrations (CRI 2), yet have numerous characteristics to support their use in remote microgrids, namely a modular design, low combustion risk and minimal geographical requirements.

185 Western Power (n.d.) Walpole mini-pumped hydro. <https://www.westernpower.com.au/our-energy-evolution/projects-and-trials/walpole-mini-pumped-hydro/> (accessed 24 October 2022).

186 ARENA (2020) Horizon Power Denham Hydrogen Demonstration < https://arena.gov.au/projects/horizon-power-denham-hydrogen-demonstration/> accessed 12 January 2023; Horizon Power (2022) Horizon Power leads the country in demonstration of hydrogen for energy use < https://www.horizonpower.com.au/about-us/news-announcements/horizon-power-leads-the-country-in-demonstration-of-hydrogen-for-energy-use/>

187 Azelio (2022). First half 2022. <https://www.azelio.com/wp-content/uploads/2022/08/wkr0006-1.pdf> (accessed 24 October 2022); Azelio (n.d.) The solution. <https://www.azelio.com/the-solution/technology/> (accessed 24 October 2022).

188 MGA Thermal (2022) MGA Thermal pilot. <https://mgathermal.com/pilot> (accessed 8 November 2022); LDES Council (2022) Net-zero power: Long duration energy storage for a renewable grid. McKinsey & Company. <https://www.mckinsey.com/capabilities/sustainability/our-insights/net-zero-power-long-duration-energy-storage-for-a-renewable-grid> (accessed 8 November 2022).

Gravity

Gravity systems are undergoing pilot-scale demonstrations (CRI 1), but they are expected to be able to offer long-duration storage for remote microgrid scales. New modular building designs are expected to offer systems that scale incrementally,[189] but, like other technologies, larger scales may be required to balance fixed capital costs. For above-ground systems, geographical constraints are moderate, with system size varying depending on capacity.[190]

Alternative technologies

Given the diversity of community types and locations, there is the potential for a range of alternative storage technologies to be considered. For example:

- **Biofuels:** Although not explored in this roadmap, biofuels could be used as a low emissions alternative to diesel generation in off-grid environments.[191] Considerations include reliability of supply and a lower shelf life compared with fossil fuels. Biogas could also be considered, but would require the conversion of gas generators.
- **Hydrogen derivatives:** These could include derivatives such as methanol, ammonia[192] and liquid organic hydrogen carriers. Methanol can be used directly by a turbine engine to generate electricity with current technology. Ammonia can be cost-effectively transported and stored using current technologies, but the combustion of ammonia for power applications is under RD&D to overcome challenges such as NO_x emissions.[193] For fuel cell-based power systems, hydrogen derivatives like liquid organic hydrogen carriers and ammonia require an additional hydrogen extraction process.

Additional technologies to consider include ancillary technologies to enable the integration and optimisation of multiple storage systems to help manage system needs, intermittency, cover medium- and long-duration power needs and provide additional reliability.

189 Energy Vault (2022) Modular by design – EVx™. <https://www.energyvault.com/evx> (accessed 18 November 2022).

190 Novel modular buildings require 0.6 to 0.8 hectares for a 50 MWh system: Kelly-Detwiler P (2021) Vaulting Into Global Energy Storage markets: Energy Vault Is A Player To Reckon With. Forbes. <https://www.forbes.com/sites/peterdetwiler/2021/12/02/vaulting-into-global-energy-storage-markets-energy-vault-is-a-player-to-reckon-with/?sh=72bc141d217b> (accessed 22 November 2022)

191 ENEA Australia, Deloitte Financial Advisory (2021) Australia's bioenergy roadmap. <https://arena.gov.au/assets/2021/11/australia-bioenergy-roadmap-report.pdf> (accessed 24 October 2022).

192 Patonia A, Poudineh R (2020) Ammonia as a storage solution for future decarbonised energy systems. Oxford Institute for Energy Studies. <https://www.oxfordenergy.org/publications/ammonia-as-a-storage-solution-for-future-decarbonized-energy-systems/> (accessed 24 October 2022).

193 Erdemir D, Dincer I (2020) A perspective on the use of ammonia as a clean fuel: Challenges and solutions. International Journal of Energy Research 45, 4827–4834.

Figure 27: Energy storage requirements for two remote communities with different energy resources

The energy storage needs for remote communities seeking to reduce their reliance on diesel have been explored through two sites with different solar and wind energy resources.

The first community is assumed to be located in a coastal location in northern Queensland with strong wind resources; the second community is located in the middle of the Northern Territory with strong solar resources. Ergon Energy Network provided total diesel generation data in half-hourly intervals from 2013 to 2018 for a remote coastal community in Queensland with an annual energy use of 13,371,500 kWh and peak demand of 2,000 kW. For comparison, the current generation of the two community sites considered the same mix, consisting of four diesel generators, one large used for primary power and the smaller sets used as back-up.

It was found that both communities required short and long duration storage. However, the requirements for long-duration varied considerably based on the renewable resources available.

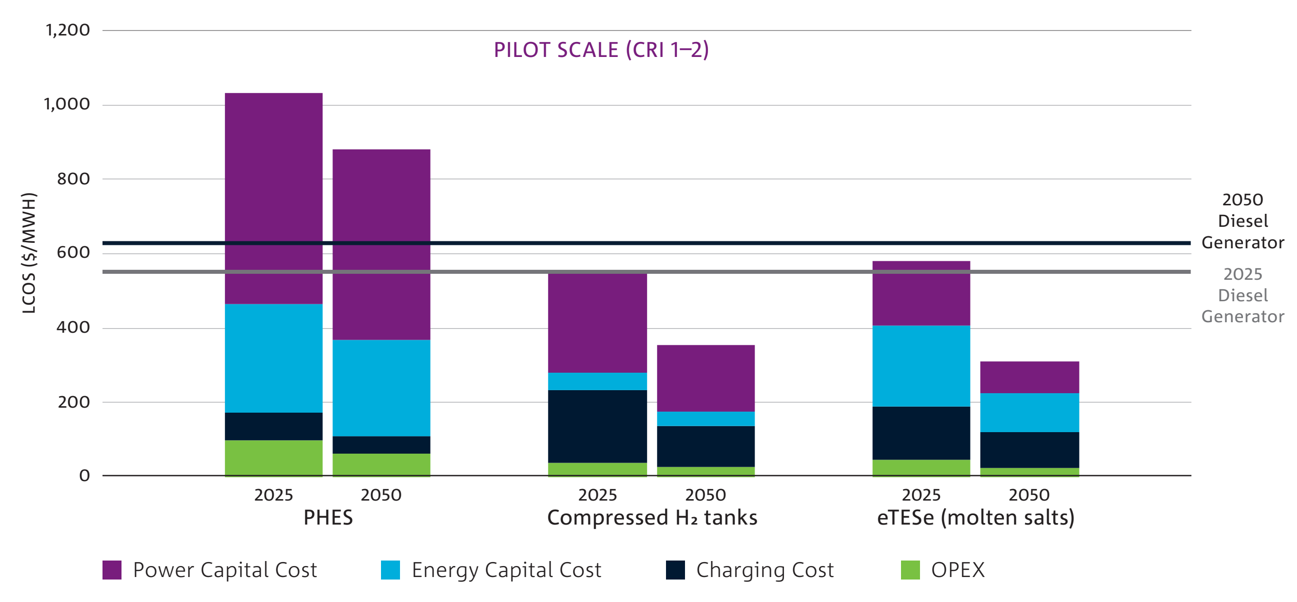
Remote community with strong wind resources

The remote community with strong wind energy resources assumed five wind turbines, each with 1.5-MW capacity, were installed. It was found that short-duration storage and long-duration storage was required.

For this location, Li-ion batteries were estimated to be the least-cost system and competitive against diesel and a gas peaking plant by 2025. The short-duration battery required a storage duration of 30 minutes and a daily complete discharge cycle, on average, to reduce intermittency. For the specific community, it was estimated that replacing diesel with wind and short-duration energy storage could meet 80% of the site's electrical load and result in an annual fuel reduction of 635 kL and a reduction of 1.7 kT in CO_2 emissions.

A long-duration energy storage system was also required. It was found that the system needed a power rating of 2.5 MW and a total storage duration of 48 hours with 20 complete discharge cycles per year, on average, in order to replace diesel (alongside the wind and short-duration technologies deployed).

LCOS results, remote community with strong wind resources, supporting 7.5MW wind (48-hour storage duration, 20 annual cycles)



Notes: See Section 3.1 for further discussion on interpreting LCOS results. For case study background and approach see Appendix D and for further information on LCOS analysis see Appendix C. Terminology: CRI, commercial readiness index in remote community application; eTESe, electricity to thermal storage to electricity; H_2, hydrogen; LCOS, levelised cost of storage; OPEX, operating expenses; PHES, pumped hydro energy storage.

The LCOS analysis for long-duration energy storage for this community is shown in the figure below. In the near term compressed hydrogen tanks and eTESe were both estimated to have a lower cost than PHES. In the long term, both compressed hydrogen tanks and eTESe were estimated to be competitive with diesel generators.

Remote community with strong solar resources

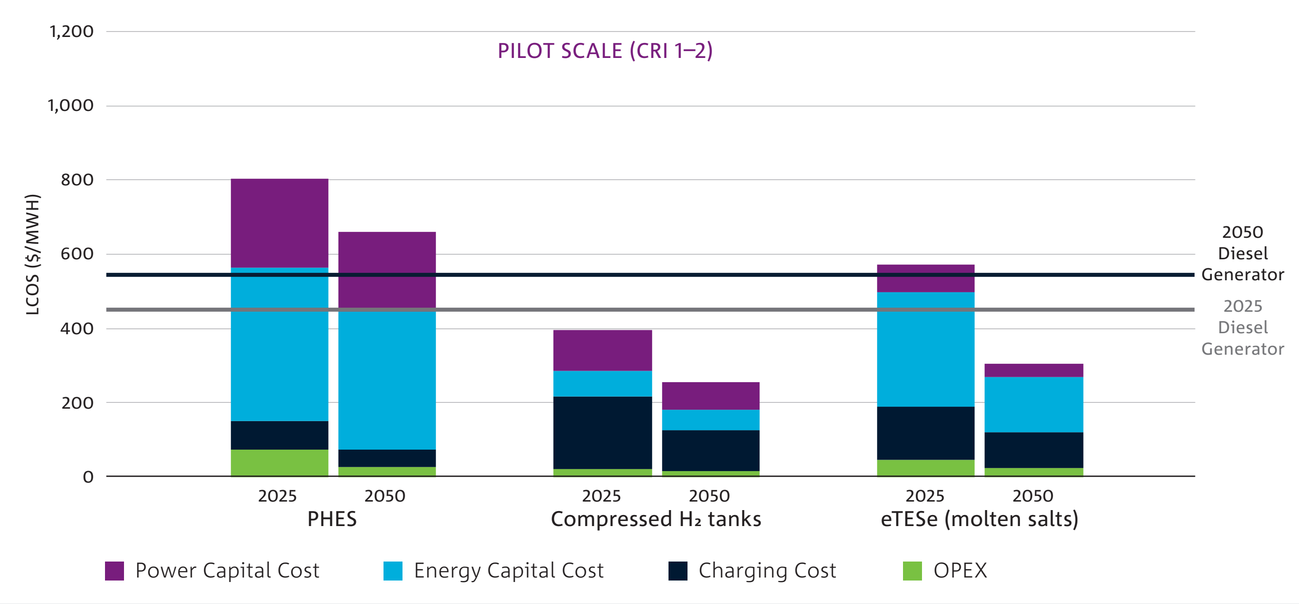
The remote community with strong solar energy resources assumed approximately 8.5 MW of solar PV was constructed. It was found that short-duration storage and long-duration storage was required, similar to the remote community with strong wind resources.

For this community, solar PV with short-duration storage was able to meet 48% of the site's electrical load. The short-duration storage technology required a storage duration of 30 minutes and was found to undergo 280 complete discharge cycles, on average, per year. Li-ion batteries were estimated to be the least-cost short-duration storage system against diesel and in 2025.

In order to replace diesel in this community, a long-duration energy storage system was required. This analysis suggested that the system needed to have a power rating of 2.5 MW and a total storage duration of 163 hours, or approximately 1 week of storage (alongside the renewable deployment and short-duration storage system). This system would need to undergo the equivalent of 14 complete discharge cycles per year. Based on the technologies considered, compressed hydrogen tanks was estimated to have the lowest cost and also be competitive in the near and long-term.

It is worth noting the difference between the long duration storage results and assumptions for the sunny community compared with the community with strong wind resources (i.e. assumptions for community with strong solar resources: 163hrs, 14 cycles; community with strong wind resources 48hrs, 20 cycles (previous figure)). The difference in assumptions in the strong solar region leads to an increase in total net present value costs for the system and an increase in the total amount of energy discharged. For PHES and compressed hydrogen tanks this change in discharged energy is greater than the net present value cost increases, leading to in an overall reduction in LCOS. For the eTESe system, the increases in discharged energy and total net present value costs are roughly equal resulting in a similar LCOS result between the two regions.

LCOS results, remote community with strong solar resources, supporting 8.5MW solar PV (163-hour storage duration, 14 annual cycles)



Notes: See Section 3.1 for further discussion on interpreting LCOS results. For case study background and approach see Appendix D and for further information on LCOS analysis see Appendix C. Terminology: CRI, commercial readiness index in remote community application; eTESe, electricity to thermal storage to electricity; H_2, hydrogen; LCOS, levelised cost of storage; OPEX, operating expenses; PHES, pumped hydro energy storage.

3.5 Mid-temperature industrial processes: Manufacturing

Thermal and chemical storage systems, as well as process electrification, have the potential to enable the manufacturing industry to cost-effectively decarbonise and meet their mid-temperature heat requirements. However, further demonstration and scale up are required to increase knowledge of decarbonisation pathways and associated storage technology options, as well as reduce real (or perceived) commercial and technical risks.

Mid-temperature industrial processes require heat at temperatures between 150°C and 500°C, and are part of a broad range of Australian industries. Examples of processes that fall into this category include the digestion phase of alumina refining, malt kilning in the beverage industry and steam for various applications in the commercial and services sectors (see Figure 28). In Australia, industrial process heat accounts for 23% of energy consumption. Of this, over 40% requires mid-temperature heat.[194]

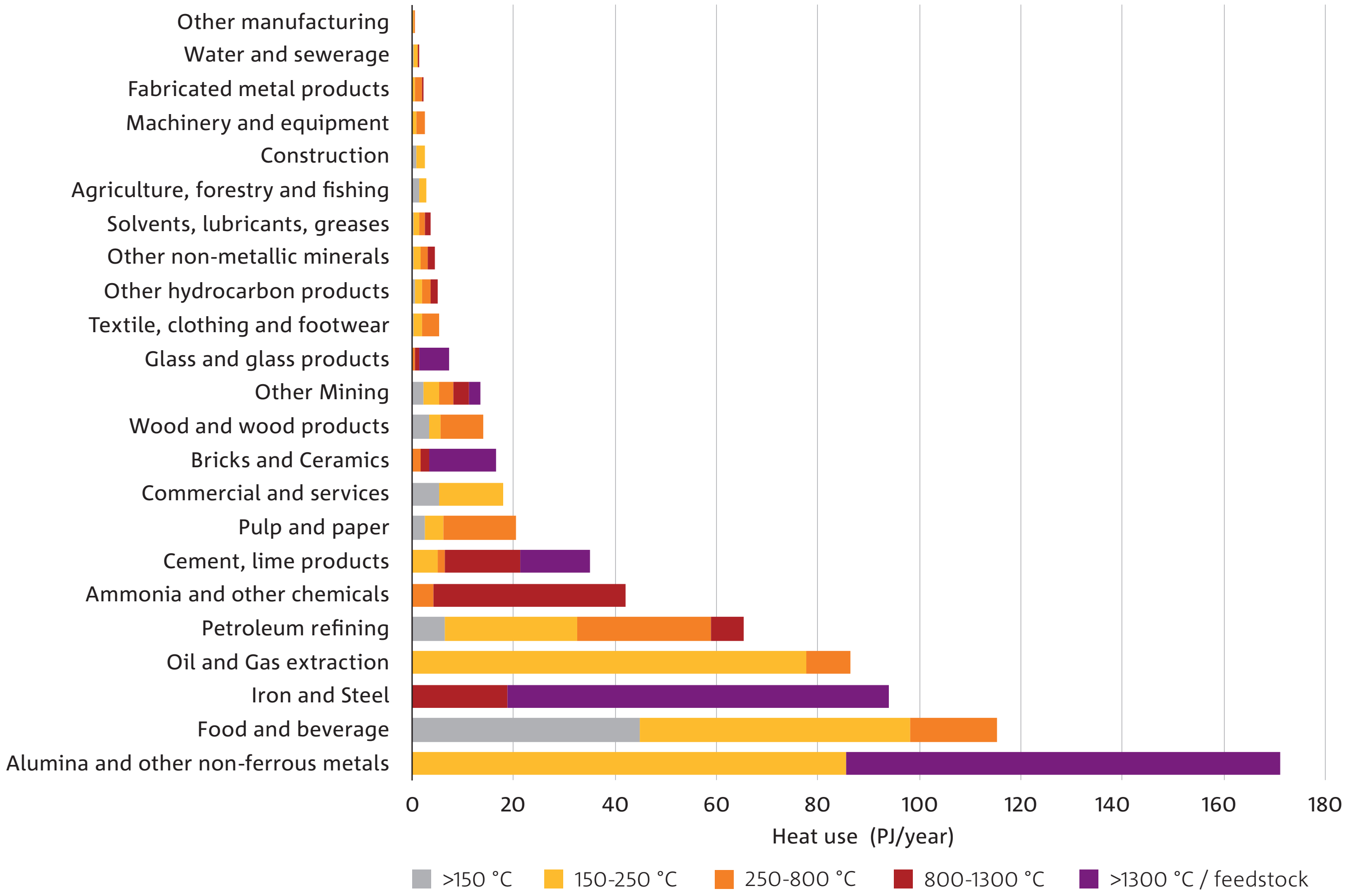
	MID-TEMPERATURE INDUSTRIAL PROCESSES: MANUFACTURING Thermal and chemical energy storage to support industrial process heat requirements
Electrochemical	*
Mechanical	*
Chemical	*
Thermal	✓

✓ Technology options explored in section

* Technology applies but not discussed in chapter, cross reference to other sections

194 Industry accounts for 44% of Australia's end use energy, of which 52% is process heat; Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/knowledge-bank/renewable-energy-options-for-industrial-process-heat/> (accessed 21 October 2022).

Figure 28: Industrial heat use in Australia 2016–17 by sector and end-use temperature[195]



Terminology: PJ, petajoules

In the manufacturing context, mid-temperatures are typically reached via the burning of natural gas (to generate process heat and steam). A key challenge for decarbonisation is how to cost-effectively provide thermal energy from a low-emission energy supply. For many manufacturers, the upfront cost of capital for the transition is a key factor in decision making, even in light of currently high east coast natural gas prices. Further, manufacturing plants often have a long lifespan and integrated and optimised processes. Because of this, technologies that impact infrastructure requirements may not be cost-effective and need to consider existing assets.

Multiple decarbonisation pathways apply to mid-temperature industrial processes, including electrification, thermal storage and alternative fuels. However, this chapter provides a deeper dive on thermal energy storage options specifically. Further information on storage deployment considerations related to electrification can be found in the discussion on major grids (Section 3.2); information on the deployment of hydrogen storage can be found in the discussion of hydrogen export and transport (see Sections 3.7 and 3.8 respectively).

195 Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/knowledge-bank/renewable-energy-options-for-industrial-process-heat/> (accessed 21 October 2022)

Role of energy storage

There are multiple pathways to decarbonising mid-temperature industrial heat, each with unique storage considerations. These include electrification, the use of alternative fuels and thermal energy storage. Despite the decarbonisation potential, the extent to which technologies are deployed will depend on a variety of factors. This includes costs relative to other solutions, land availability, operational requirements (i.e. day / night operations), and renewable resource availability (solar, wind, waste energy streams).

Although they have the potential to be cost-effective, further investigation and scale up are required because uptake and commercial and technical risk will vary by process and site. For example, although thermal storage media such as molten salts are being used in power applications, there are limited commercially available end-to-end thermal storage systems for different industrial process heat applications, particularly at a small and modular scale.

Electrification

Electrification has the potential to decarbonise a large portion of mid-temperature processes (150–500°C). This could be achieved with currently mature technology options, whereas the remaining portion could be electrified with technologies that are still under development.[196] Examples that have been used across various manufacturing operations include mechanical vapour recompression, electric boilers and infrared heating.[197] Although onsite renewable energy and storage can be deployed to support this pathway, manufacturers located around major cities may face space constraints. In this case, leveraging local grids and grid-side storage infrastructure will be important (for storage implications of electrification, see also Section 3.2, Major Grids).

Thermal energy storage

Various solar thermal installations could be paired with thermal energy storage media to generate and store the heat required. For example, converting sunlight into thermal energy can be done via a CST system with thermal storage. Thermal energy storage could be used to provide thermal energy during periods with low sunlight and overnight. These systems can simultaneously store and generate thermal energy (i.e. they can charge and discharge at the same time).

An eTESh system (thermal storage medium charged with electricity as an input and heat as an output) could take advantage of the local grid and be used to generate and store the heat required for a given mid-temperature process. Here, storage can be used to generate the required heat and to minimise the average cost of heat for the user. Where grid connected, energy storage may be beneficial for the purpose of time shifting energy, allowing an operation to store heat by using cheap renewable electricity during the day. This avoids the need to use peak electricity for heating, and thus minimises the peak power charge that the user incurs.

Alternative fuels

Alternative fuels can replace natural gas, in which case chemical storage is required to ensure that an adequate supply of the fuel is available. For example, hydrogen, synthetic methane or biofuels could be used in place of natural gas. The use of alternative fuels requires appropriate storage at multiple points along the fuel supply chain, including production site, distribution (pipelines or tank transportation), and onsite buffering.

196 Madeddu S, Ueckerdt F, Pehl M, Peterseim J, Lord M, Kumar KA, Krüger C, Luderer G (2020) The CO_2 reduction potential for the European industry via direct electrification of heat supply (power-to-heat). Environmental Research Letters 15, 124004.

197 Madeddu et al. (2020) The CO_2 reduction potential for the European industry via direct electrification of heat supply (power-to-heat). Environmental Research Letters 15, 124004.

Deployment considerations

As with other industries, storage deployment considerations vary by decarbonisation pathway and operational factors related to an individual manufacturing operation. Although not exhaustive, this section builds on the considerations discussed in Section 3.1 to highlight specific storage deployment considerations associated thermal storage technologies that could be used under the CST and eTESh and solar pathways.

Cost: Manufacturers face short payback periods and have a high sensitivity to investment risk, making high-CAPEX energy storage systems and associated process changes challenging to implement.[198] Capital and operating costs will vary on a site-by-site basis depending on the application (e.g. if there a need for high- or low-pressure steam, hot air or water) and its specific operating requirements (e.g. inlet and outlet temperatures and pressures). To support discussion, the levelised cost of a tonne of steam has been analysed (see Figure 29).

- **Maturity:** Many manufacturers will require storage technologies that are not only technically viable and mature, but also those that have been widely deployed as end-to-end systems across different manufacturing processes. There may be some manufacturers willing to take on systems with lower maturity that offer strong sustainability outcomes and longer-term cost savings.
- **Economies of scale, modularity and scalability:** Systems that are in discrete units that can be invested in at small scales, and scaled up as required, will likely be preferable in smaller-scale manufacturing locations to overcome barriers related to CAPEX. Conversely, co-investment in larger systems within industrial clusters could allow manufacturers to benefit from economies of scale and the efficiencies created through the sharing of assets.
- **Geographical and site characteristics:** The footprint of different technologies will vary based on the energy input (e.g. electricity versus solar heat), as well as the temperature differential required for the thermal process. For manufacturers located around towns and cities, land availability may be limited. Higher energy density technology options with smaller footprints may be preferable in such contexts. Conversely, regional and remote manufacturing plants may have flexibility to deploy larger systems if they have access to more land.
- **System integration:** Systems that are easy to integrate into a site with minimal balance of plant or required infrastructure will likely be preferable for manufacturers. The ability to readily integrate systems will depend on existing site infrastructure.
- **Target heat delivery temperature:** The desired process heat delivery temperature may impact which thermal storage technologies are best suited. This is due to the different temperature ranges over which different thermal storage technologies are most efficient and cost-effective. For latent heat systems that involve a phase change, it is generally preferable to provide delivered heat at or near the phase change temperature. For sensible heat systems, it is generally preferable to operate the storage system at a higher temperatures than the temperature required for the delivered process heat. The higher the temperature differential between stored thermal energy and the required process heat, the lower the quantity and cost of the required energy storage.
- **Safety and risk management:** The safety of equipment is a priority for manufacturing facilities and may present additional considerations in high-density metropolitan areas. There are inherent risks involved with the use of medium- and high-temperature pressurised water or steam, but manufacturers that use steam are likely to be already managing these risks. For example, sites that already have high-pressure steam infrastructure require minimal plant changes to balance the output of a steam accumulator.[199] Therefore, it will be important for a manufacturer to understand if and how these existing practices will need to evolve based on the technology used.

198 Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/knowledge-bank/renewable-energy-options-for-industrial-process-heat> (accessed 21 October 2022).

199 Internal source.

Technology options

The approach to decarbonisation of mid-temperature process heat will alter storage options and will need to be supported by further testing and demonstration to increase knowledge and reduce real (or perceived) commercial and technical risks. The technology options discussed are not exhaustive and provide examples of the application of deployment considerations discussed previously. These are summarised in Table 10. To support discussion, levelised cost analysis has been included at the end of this section. This analysis explores the use of thermal storage for low-pressure steam as an output. However, it is important to recognise that different manufacturers may require different outputs, such as steam at different pressures, hot air and hot water.

More information on each of the technologies and the approach to LCOS modelling can be found in Sections 2.2, Section 3.1 and Appendices C and E.

Steam accumulators

This technology has multiple supported demonstrations (CRI 5) and is available for purchase from suppliers worldwide. The size of these systems varies by site requirements, but vessels are often modular and assembled as multiple units onsite. These systems can face commercial limitations beyond temperatures of 300°C because the thickness of the storage vessels becomes excessively large and difficult to manufacture.[201]

Concrete and packed bed

Concrete and packed bed systems are undergoing commercial-scale demonstrations (CRI 2–3).[202] These are modular (40-foot shipping containers) and scalable, which can assist integration into existing manufacturing systems.[203] Although these systems are low cost, they have lower energy densities than molten salts.[204]

Table 10: Summary of deployment considerations for thermal storage technologies in manufacturing (low-pressure steam)

Consideration[200]	Steam accumulators	Concrete and packed bed	Molten salts	Graphite	MGA
Maturity (CRI)	5	2–3	1–2	1–2	1
Modularity and scalability	Vessels can be modular and assembled as multiple units	Modular and scalable depending on system design	Current technology not modular and scalable; modular systems under development	Modular and scalable depending on system design	Modular and scalable depending on system design
Geographical and site characteristics	Depends on the scale required and whether the system is deployed as part of a CST system and (moderate to large footprint, requires a solar array) or an eTES system (small to moderate footprint, doesn't require land unless deploying onsite VRE)				
Target heat delivery temperature	Commercially feasible up to 300°C	Up to ~400°C (concrete) and ~800°C (packed bed)	Typically up to 600°C	From 200°C to over 750°C	Up to ~800°C
System integration	N/A	Typically deployed for eTES applications Can be considered for CST applications	Most commonly deployed in CST applications Integrates with eTES	Technology proponents are targeting the eTES market Can be considered for CST	Integrates with TES systems CST systems have been tested

Terminology: CRI, commercial readiness index; CST, concentrated solar thermal; eTES, thermal energy storage (electricity input); MGA, miscibility gap alloys.

200 Explanation of the criteria can be found in Deployment Considerations in Section 3.1; Sources can be found in Appendix E.

201 Lovegrove et al. (2019) Renewable energy options for industrial process heat appendices. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/appendices-renewable-energy-options-for-industrial-process-heat.pdf> (accessed 22 October 2022).

202 IRENA (2020) Innovation outlook: Thermal energy storage. IRENA, Abu Dhabi.

203 Internal source.

204 Internal source.

These technologies are well suited for low- and mid-temperature manufacturing processes, with the ability to discharge temperatures of 400°C for concrete or up to 800°C for packed beds. To improve safety, packed bed systems can also be installed underground.[205]

Graphite

Graphite as a thermal energy storage technology is undergoing pilot-scale demonstrations (CRI 1–2). Graphite systems generally operate from 200°C to over 750°C,[206] within the temperature range required for mid-temperature heat processes. These systems are flexible to manufacturing site requirements because they are modular and scalable by design. The materials are not flammable or reactive, posing a low risk of fire. Technical challenges include the deformation of graphite under higher operating temperatures, and the need for an inert atmosphere to prevent oxidation.

Molten salts

Molten salts within CSP systems are relatively mature (CRI 4–5) and have an operating range of around 300–600°C, making them suitable for mid-temperature industrial process heat. However small-scale CST systems have a moderate footprint, and would only be applicable for a plant with several hectares of adjacent land (e.g. in regional or remote areas).

Molten salts used with a heat pump or heat exchanger for thermal energy applications are still undergoing RD&D (CRI 1). Due to the relatively high freezing point of most molten salts (285°C), they are better suited to process heat applications above this temperature (220–565°C).[207] However, operating temperatures can be altered through the salt composition to better match end-use application. As with most thermal energy storage technologies, the footprint of molten salt systems can vary significantly depending on the application. Typical molten salt storage systems use a two-tank system, but modular systems are in development. Technical challenges include the corrosivity and decomposition of molten salts at temperatures above 600°C, and preventing the molten salts from hardening by maintaining temperatures above melting point or by using antifreeze systems.

Miscibility gap alloys

MGA blocks are still undergoing RD&D (CRI 1). They have wide operating temperatures of 232–800°C, which can align to mid-temperature industrial processes, have high thermal conductivity and thermal stability compared to other mediums such as molten salts. These blocks are modular and able to be stacked and scaled in insulated storage tanks. To benefit from the key feature of this technology (latent heat storage), the melting point of the phase change material must align with the end-use process temperature. Challenges include the material and manufacturing costs compared to molten salts.

Alternative storage technologies

Technologies that may also be deemed applicable for mid-temperature storage for industrial processes include hydrogen and bioenergy storage systems to support the use of alternative fuels in industrial applications, geothermal energy storage, hot water storage (for temperatures up to 180°C) and additional thermal energy storage systems, such as thermal oils.[208]

Given Australia has several manufacturing precincts, there may be potential to consider shared infrastructure. This shared infrastructure could encompass both heat and power requirements and elevate footprint and capital cost constraints faced by some manufacturers. Further, recovered heat can be utilised or augmented for other processes, used to generate electrical or mechanical power, or to provide district heating.[209] However, further analysis is required to understand the potential to utilise recovered heat in mid-temperature manufacturing processes and industrial precincts.

205 Knobloch et al. (2021) A partially underground rock bed thermal energy storage with a novel air flow configuration. Applied Energy 315, 118931; Zhang et al. (2016) Thermal energy storage: Recent developments and practical aspects. Progress in Energy and Combustion Science 53, 1–40.

206 Guan et al. (2020) Regulation of the output temperature in a novel water heating system using solid graphite as sensible heat thermal energy storage medium: Effects of water tank. Energy Reports 6 (Supplement 7), 160–171; Graphite Energy (2022) Proven, reliable graphite thermal energy storage. <https://www.graphiteenergy.com/technology> (accessed 18 November 2022).

207 Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/knowledge-bank/renewable-energy-options-for-industrial-process-heat/> (accessed 21 October 2022)

208 Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/knowledge-bank/renewable-energy-options-for-industrial-process-heat/> (accessed 21 October 2022)

209 Jouhara H, Khordehgah N, Almahmoud S, Delpech B, Chauhan A, Tassou SA (2018) Waste heat recovery technologies and applications. Thermal Science and Engineering Progress 6, 268–289; IEA (2022) District heating. <https://www.iea.org/reports/district-heating> (accessed 11 November 2022).

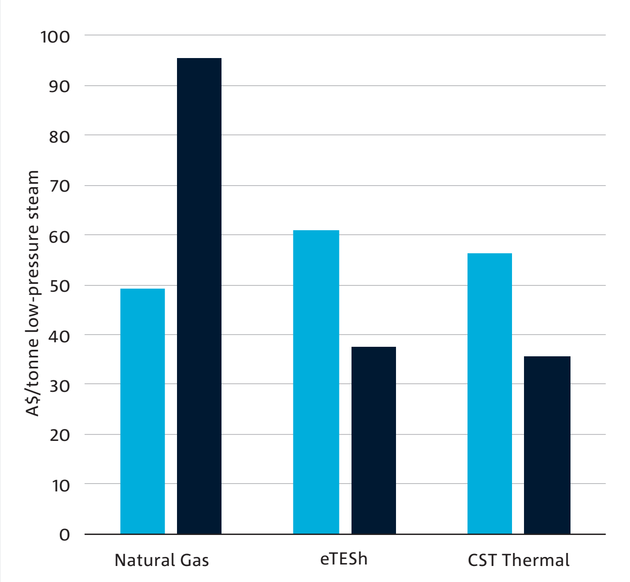
Figure 29: Levelised cost of low-pressure steam[210]

Techno-economic modelling was conducted to compare the cost of providing low-pressure steam at a temperature of 250°C using natural gas, CST and eTESh (molten salts).

The results indicate that thermal storage systems can be competitive with natural gas in the long-term. However, the competitiveness of these systems in the short-term is dependent on natural gas price assumptions. This report has elected to exclude current gas price volatility from the analysis (see Appendix C for price assumptions). If the currently high gas prices are sustained then thermal systems could be competitive in the near term.

Although these technologies can be cost-effective, the uptake of these technologies faces several challenges. For example, although thermal storage media such as molten salts are being used in power applications, there are limited commercially available end-to-end thermal storage systems for different industrial process heat applications. This introduces technology and process change risks into operations and the requirement for capital expenditure. Further, compared with other storage processes, there appears to be limited information and a lack of knowledge about thermal storage technology options available. However, recent increases in east coast natural gas prices, coupled with decarbonisation objectives, may incentivise many to take on these challenges.

Levelised cost of tonne low-pressure steam (250°C outlet temperature)



Terminology: CST Thermal, concentrated solar thermal for steam generation; eTESh, electricity to thermal storage for heat (steam generation).

210 For a summary of the methodology and assumptions, see Appendix D.

3.6 High-temperature industrial processes: Alumina refining

The decarbonisation of Australian industries that require high temperature process heat, such as alumina calcination, can have significant implications on storage, with the appropriate solution depending on the chosen decarbonisation pathway. However, industry decisions related to storage will be made in the context of a broader and highly integrated system. Such decisions often bear high up-front costs and are high-risk exercises which can be exacerbated by insufficient information due to a lack of technology maturity and scale.

Decarbonisation of high-temperature industrial processes is extremely challenging given their requirement for temperatures above 500°C, the scale and complexity of the operations with these types of processes and their reliance on fossil fuels to achieve the desired temperatures. This challenge is compounded by a lack of available and/or proven technologies that can operate at this scale. Examples of these industrial processes include high-temperature kilning for mineral processing operations (including iron, alumina, lithium, nickel and mineral sands), steelmaking, and the production of ammonia, cement and lime products.[211]

	HIGH-TEMPERATURE INDUSTRIAL PROCESSES: ALUMINA REFINING Thermal and chemical energy storage to support industrial process heat requirements
Electrochemical	*
Mechanical	*
Chemical	*
Thermal	✓

✓ Technology options explored in section

* Technology applies but not discussed in chapter, cross reference to other sections

211 Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/knowledge-bank/renewable-energy-options-for-industrial-process-heat/> (accessed 21 October 2022).

The calcination process in alumina refining provides a strong example of the scale and complexity of the decarbonisation and potential storage challenges that exist for high-temperature industrial processes. Alumina refining is the conversion, through the various steps of the Bayer process, of bauxite ore to alumina. The process heat requirements for alumina refining are a combination of low- to mid- temperature heat for digestion (between 125°C and 280°C, depending on the quality of the bauxite) and high temperatures reaching approximately 800–1,100°C for the calcination process. Each alumina refinery has significant energy demands, which must be met continuously,[212] with the calcination process accounting for approximately one-third of the energy consumed onsite.

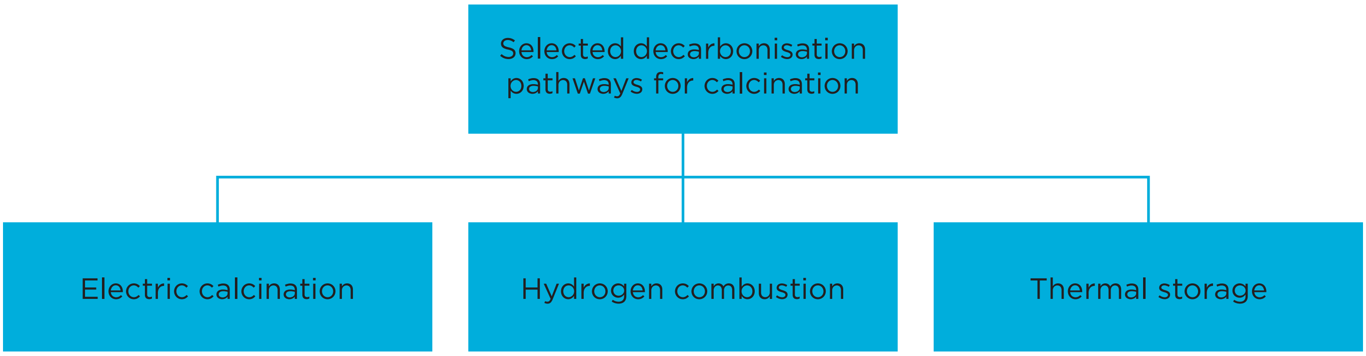
Australia has six alumina refineries: four situated in south-west WA connected to the SWIS and two located in Queensland connected to the NEM.[213] Currently, alumina refineries using the Bayer process are collectively the largest users of natural gas in Australia and the dominant contributor to national greenhouse gas emissions from the mining and minerals sector (responsible for 40% of national mineral CO_2 emissions).[214] This totalled 24% of national direct emissions (14 million tonnes of CO_2 equivalent) in 2019.[215] Historically, alumina refineries relied on the combustion of fossil fuels (natural gas and coal) to provide the high-temperature process heat required.

Multiple calcination decarbonisation pathways are currently being explored, but all are at a low TRL and all have significant storage implications given the scale of the industry.

Role of energy storage

Based on industry consultations, three major decarbonisation pathways have been selected for calcination (see Figure 30) to better understand the Australian energy storage implications. Although these pathways are presented separately, in reality they may be used together as part of a hybrid energy supply and storage system for calcination and digestion (discussed further as alternative technology options).

Figure 30: Calcination decarbonisation pathways



212 Butler et al. (2021) Australian industry energy transitions initiative Phase 1 technical report. ClimateWorks Australia. <https://energytransitionsinitiative.org/wp-content/uploads/2021/06/Phase-1-Technical-Report-June-2021.pdf> (accessed 24 October 2022).

213 Australian Aluminium Council (2021) Australian alumina. <https://aluminium.org.au/australian-alumina/> (accessed 16 September 2022).

214 Bader R, Lovegrove K, Bayon A, Beath A (2019) Feasibility study of CST technologies for the low temperature requirements of the Bayer alumina process. ITP Thermal, Turner.

215 ARENA (2021) ALCOA to investigate low emissions alumina. <https://arena.gov.au/news/alcoa-to-investigate-low-emissions-alumina/> (accessed 21 October 2022).

Electric calcination

In this pathway, the calcination process is electrified, with the electricity used to generate thermal energy, displacing the need for thermal energy from fuels. Sites may primarily make use of grid electricity, potentially combined with some onsite VRE. An Australian Renewable Energy Agency (ARENA)-funded project to develop a pilot electric calcination plant is underway.[216]

Electric calcination will require significant levels of electricity storage on the grid, but also has the potential to provide demand response and support greater levels of VRE. For example, if grid electricity is used by alumina refineries, an additional burden of electricity supply and storage may fall onto the major grids. This could present risks for the grid's capacity to meet the increased demand, and potentially cause the need for large-scale grid storage or network augmentation. However, alumina refiners can provide demand response to the grid.[217] Therefore, there is the potential to increase these activities and provide firming to support greater levels of VRE deployments in a major grid (for further implications, see Section 3.2). Further, because thermal energy is generated for the calcination process, this pathway can make use of stored thermal energy as an input. The provision of this storage may also enable participation in the demand–response market.

Hydrogen combustion

In this pathway, hydrogen is used as an alternative process heat source and is combusted to provide thermal energy for calcination. A key challenge with hydrogen (and other renewables, such as those derived from biomass) is its cost competitiveness with natural gas, particularly when considering west coast gas prices. ARENA is currently funding a technical feasibility study investigating the use of hydrogen to decarbonise alumina refining at a Rio Tinto refinery in Gladstone, Queensland.[218]

The hydrogen combustion pathway would require a substantial quantity of stored hydrogen to provide a consistent supply to support production. This hydrogen could be secured from an offsite hydrogen producer and for example, could be delivered via a 100% hydrogen pipeline. Additional hydrogen storage may be warranted onsite or at the hydrogen production site to ensure a reliable supply. The scale of hydrogen required could be supported by national strategies related to the development of hydrogen hubs. This scale is further explored through a case study (see Figure 31). For an extended discussion of hydrogen storage options for different distribution models see Sections 3.7 and 3.8.

Thermal energy storage

Two thermal energy storage systems have been considered for use in alumina calcination: CST and eTESh. CST with a thermal storage medium can be used to store the high-temperature heat required. Such a system could make use of storage to maintain thermal energy during low CST generation periods, such as overnight. In an eTESh system, a thermal storage medium is charged with electricity as an input to generate and store the heat required for the calcination process. The medium (e.g. air) is then used as the heat transfer fluid to transmit thermal energy stored for the calcination process.

216 ARENA (2022) Alcoa renewable powered electric calcination pilot. <https://arena.gov.au/projects/alcoa-renewable-powered-electric-calcination-pilot/> (accessed 24 October 2022).

217 Australian Aluminium Council (2022) Australian aluminium pathways fact sheet #3: Alumina. Australia will help develop low carbon alumina refining technologies for the world. <https://aluminium.org.au/wp-content/uploads/2022/07/220719-PATHWAY-FACT-SHEET-03-ALUMINA.pdf> (accessed 24 October 2022).

218 ARENA (2022) Rio Tinto Pacific operations hydrogen program. <https://arena.gov.au/projects/rio-tinto-pacific-operations-hydrogen-program/> (accessed 24 October 2022).

The eTESh pathway differs from electric calcination given the use of a thermal storage medium, but has similar grid storage implications if the electrical input is sourced from the grid. As mentioned earlier, this may require additional grid augmentation or grid-based storage systems. Although not analysed, the eTESh pathway could also source its energy via an independent power producer or by using onsite VRE.

For a thermal storage medium to support continuous operations, it would need to be able to sustain temperatures beyond those required for the operation (at ~800–1,100°C). As a result, there are very few thermal storage media that could be used for high-temperature industrial processes.

Deployment considerations

Storage deployment considerations vary by decarbonisation pathway and operational factors related to an individual alumina refinery. Although not exhaustive, this section builds on the considerations discussed in Section 3.1 to highlight specific deployment considerations.

- **Cost:** All decarbonisation pathways and technologies discussed in this section will require further analysis, research and piloting in order to identify low-cost pathways. Cost factors that will play a key role in determining the chosen pathway and storage system include the cost of electricity from the grid, the cost of storage technologies once mature and any new processes or modifications required once technically proven.
- **Maturity:** High-temperature systems are, in general, at lower technology and commercial readiness levels than low-temperature systems. Industries with high-temperature needs will require each pathway to reach technical maturity in order to understand performance parameters, expected costs of storage and integration into plant processes. Some industry players have the appetite and financing to invest and accelerate emerging technologies and are currently co-investing with government in studies and pilot projects to accelerate storage systems and associated emerging industrial processes.
- **Geographical and site characteristics:** The pathway and storage system chosen will depend on industry location, including proximity to major grids and hydrogen infrastructure, as well as industry clusters. For example, there are four major alumina refineries all located in WA that could benefit from sharing the same pathway.
- **System integration:** All storage technologies choices require careful consideration with respect to integration within plant systems and the overall energy system. For example, at the plant level hydrogen storage will require calcination processes compatible with hydrogen. At an energy system level this would require hydrogen infrastructure. Similarly, electric calcination would have electricity storage implications across the grid.
- With respect to high-temperature thermal storage, some thermal mediums can be integrated with CST using thermal energy from solar radiation as an input or be integrated with eTESh systems, using electricity to heat the storage medium and output heat when required.

- **Safety and risk management:** Alumina refineries, as with other heavy industrial sites, have comprehensive safety and risk management practices to protect personnel, operations and the nearby local community. Existing practices related to working with high temperatures can be leveraged. New industry practices related to the use of emerging technologies such as hydrogen, will need to be developed. Given each decarbonisation pathway (and storage technology) can impact plant processes, these practices will need to be reviewed.
- **Target heat delivery temperature:** For thermal storage technologies in particular, meeting the required output temperature for calcination is critical for candidate technologies. If new approaches to lower-temperature calcination can be achieved, this may enable a greater range of thermal storage technologies to service this lower-temperature requirement.

Technology options

Different decarbonisation pathways are being considered for high temperature processes; however, regardless of the chosen pathway, storage options are limited and require further development and consideration in the context of a broader and highly integrated system.

This section focuses on thermal storage technology options that could potentially be used for high-temperature processes (of 800°C and above). The technology options are not exhaustive and provide examples of the application of deployment considerations discussed above. With respect to thermal storage mediums applicable to high-temperature thermal processing, a summary of considerations is provided in Table 11. More information on each of the technologies and the approach to case studies can be found in Sections 2.2 and Appendices D and E.

To support discussion, a case study exploring a hydrogen combustion and electrified digestion pathway has been included at the end of this section. This analysis explores the potential scale of energy storage required for the decarbonisation of the four alumina refineries located in south-west WA. Storage technology options that could support electric calcination and hydrogen combustion pathways can be found in the discussion of major grids and hydrogen export respectively (see Sections 3.2 and 3.7).

Table 11: Summary of deployment considerations for thermal storage technologies in alumina calcination

Consideration[219]	Silicon	Particle systems[220]
Maturity in alumina applications	TRL 4–6	TRL 5–6
Target heat delivery temperature	Latent systems target temperatures above 1,000°C[221]	Typically targets temperatures of 800–1,000°C Some proponents target temperatures of up to 1,500°C[222]
System integration	Integrates with eTES systems	Integrates with CST

Terminology: CRI, commercial readiness index; CST, concentrated solar thermal; eTES, thermal energy storage (electricity input); TRL, technological readiness level.

219 Explanation of the criteria can be found in Deployment Considerations in Section 3.1; References can be found in Appendix E.

220 CSIRO (2021) CSIRO plays part in US next-gen solar thermal technology. <https://www.csiro.au/en/news/news-releases/2021/csiro-plays-part-in-us-next-gen-solar-thermal-technology> (accessed 24 October 2022).

221 1414 Degrees (2021) SiBox commercialisation path. <https://1414degrees.com.au/sibox-commercialisation-path/> (accessed 23 November 2022); 1414 Degrees (2019) Technology & commercial review update. ASX. <https://1414degrees.com.au/wp-content/uploads/2020/06/Technology-Commercial-Review-Update-1.pdf> (accessed 23 November 2022).

222 Heliogen (2019) Press release: Heliogen achieves breakthrough temperatures from concentrated sunlight for industrial processes. <https://heliogen.com/press-release-heliogen-achieves-breakthrough-temperatures-from-concentrated-sunlight-for-industrial-processes-with-momentum-toward-commercial-hydrogen-fuel-creation/#:~:text=In%20addition%20to%20industrial%20process,such%20as%20hydrogen%20or%20syngas> (accessed 23 November 2022).

Silicon

The maturity of silicon systems varies depending on system design and the target temperature range. Latent heat systems targeting the melting point of silicon at 1,414°C are at TRL 4–5, and are typically used in eTES systems. This temperature range makes silicon well suited for high-temperature industrial processes. However, silicon is not currently used in CST systems because it could be too optically inefficient to beam solar radiation into silicon storage containers. However, further research is required. Further research is required to determine future applicability of silicon for CST. Technical challenges include the thermal expansion of silicon and operation at ultra-high temperatures, which can lower the strength and durability of containment vessels.

Particle systems

Particle systems are a slightly more mature technology (TRL 5–6) than silicon, but are still undergoing RD&D. This is due to the amount of research and development performed worldwide. These systems typically target a temperature of 800–1,000°C depending on the type of system and material. Some systems are capable of storing bulk amounts of thermal energy at temperatures of up to 1,500°C, making particles ideal for high-temperature mineral processes, such as calcination.[223] Particles are being designed for use in CST systems. Further analysis would be needed to determine the applicability of particles with eTESh systems. However, they show some potential, given particles can function as a fluid and be used to trickle or fall over tubes or electric heaters to capture thermal energy.

Alternative technologies

Given the emergence of high-temperature thermal storage media, lower TRL and CRI technologies should be considered as they progress to higher levels of maturity. For example, graphite systems can operate with heat outputs up to 1,500°C,[224] and are currently under R&D.[225]

Given the limited options for storing thermal energy at high temperatures and the costs of transitioning an operation, it is important for alumina refiners to consider alternative strategies, such as using hybrid systems. Although beyond the scope of this report, decarbonisation of alumina could be achieved with a hybrid strategy that uses multiple decarbonisation pathways together, taking into consideration both digestion and calcination and optimising the strategy for a given site to achieve the energy requirements for both (e.g. considering both a thermal storage system and electrification).

There are also various other approaches being actively researched, for example through the Heavy Industry Low-carbon Transition Cooperative Research Centre (HILT CRC).[226] Relevant projects under development through the HILT CRC include: evaluating the use of thermal storage and mechanical vapour recompression to allow variable renewable input for steam in alumina production; preliminary assessment of the technical and economic feasibility of key options for low-carbon alumina calcination; green hydrogen supply modelling; and green heat for industry.[227]

223 Heliogen (2019) Press release: Heliogen achieves breakthrough temperatures from concentrated sunlight for indusutrial processes. <https://heliogen.com/press-release-heliogen-achieves-breakthrough-temperatures-from-concentrated-sunlight-for-industrial-processes-with-momentum-toward-commercial-hydrogen-fuel-creation/#:~:text=In%20addition%20to%20industrial%20process,such%20as%20hydrogen%20or%20syngas> (accessed 23 November 2022).

224 Briggs J Antora Energy (2021) Solid State Thermal Battery. ARPA-E DAYS Annu. Meet., Advanced Research Projects Agency – Energy, cited in Novotny et al. (2022) Review of Carnot battery technology commercial development. Energies 15, 647; Guan et al. (2020) Regulation of the output temperature in a novel water heating system using solid graphite as sensible heat thermal energy storage medium: Effects of water tank. Energy Reports 6 (Supplement 7), 160–171.

225 Antora Energy (2022) Zero-carbon industrial heat & power. <https://antoraenergy.com/technology> (accessed 23 November 2022); ARPA-E (2010) Antora Energy: Solid state thermal battery <https://arpa-e.energy.gov/technologies/projects/solid-state-thermal-battery> (accessed 8 November 2022).

226 HILT CRC (n.d.) Home. <https://www.hiltcrc.com.au/> (accessed 24 October 2022).

227 HILT CRC (n.d.) QuickStart projects. <https://www.hiltcrc.com.au/quickstart-projects> (accessed 24 October 2022).

Figure 31: The potential scale of storage related to the electrification of alumina digestion and the use of hydrogen for calcination [228]

The potential scale of energy storage required has been explored by considering the decarbonisation of the four alumina refineries located in south-west WA. Together, these refineries are responsible for 14 Mt per year alumina and have an estimated total consumption of energy of 150 PJ per year (36 TWh), derived largely from natural gas.

Although each of the four refineries will determine its own decarbonisation strategy based on individual operations, for simplicity this case study considers the decarbonisation of calcination using the hydrogen combustion pathway and the electrification of the digestion process (which is a mid-temperature process and explored further in relation to the manufacturing industry; see Section 3.5). As a rough-order magnitude estimate, the analysis assumes that approximately 70% of energy from natural gas is used for digestion and 30% is used for calcination, acknowledging that this assumption differs across sites and that electricity is also consumed for various uses across operations. It is also important to note that both decarbonisation pathways are still low TRL, as with the other pathways discussed, and that it is highly likely that multiple pathways and technologies will be considered depending on the operation.

The analysis found that by 2050 there would need to be approximately 250 t per day (46 PJ) of hydrogen storage if the four refiners in the region chose to use hydrogen to decarbonise their calcination phases. With regard to digestion, the analysis found that such a strategy could result in the need for 3 GW (6 TWh per year) of additional electrical storage capacity in the SWIS.

Estimated additional energy and storage requirements for Alumina refining in South-West WA under specific case assumptions

		2050 ESTIMATE
DIGESTION	Energy for digestion	25 TWh/year
	Storage: Power capacity	**3 GW**
	Storage: Energy capacity	**6 TWh/year**
CALCINATION	Energy for calcination	11 TWh/yr (1.2 GW)
	Energy and storage: Thermal calcination using hydrogen	
	H_2 required for calcination	1,000 t/day
	Electricity for H_2 generation	17 TWh/year
	Electrolyser size	2.5GW
	Storage: Extra hydrogen required	**250 t/day**

228 For a summary of the methodology and assumptions, see Appendix D.

3.7 New energy exports: Hydrogen export

Large-scale storage will play a critical role in realising Australia's hydrogen export industry and could support the development of a domestic hydrogen economy. However, the choice and type of storage required will depend on how a given export value chain is optimised, with implications for maritime and pipeline infrastructure.

In the hydrogen export value chain, hydrogen is generated using renewable energy, then either liquefied or converted to a derivative, such as ammonia, before export. Unlike the other industries analysed, hydrogen export represents an entirely new energy export industry for Australia, bringing about a broad range of challenges and uncertainties. Beyond the development of policies and standards, the industry requires rapid scale up and integration of commercially competitive and developing hydrogen technologies in global markets.

Energy storage will be essential to enable the growth of Australia's hydrogen export industry. Energy storage can be used to provide a reliable and consistent supply of energy to support the hydrogen value chain from production through to the point of export. However, the hydrogen export industry will use various complex value chains, and individual project proponents will take responsibility for optimising their respective value chains and meeting their operational storage and buffering needs. The scale of demand and type of product (hydrogen or derivatives) will also depend on the strategic directions taken by export partners such as Japan, Korea, Singapore and Germany, which are driven by end-use markets in those countries.

	NEW ENERGY EXPORTS: HYDROGEN EXPORT Storage of hydrogen (as an example of large and distributed chemical energy storage) to support export and transport
Electrochemical	*
Mechanical	*
Chemical	✓
Thermal	*

✓ Technology options explored in section

* Technology applies but not discussed in chapter, cross reference to other sections

Given the potential scale of the export industry, it is important for Australia to understand infrastructure implications and opportunities to support export scale up and domestic applications based on the volume and type of storage that may be required. This includes storage considerations related to existing infrastructure and understanding the value of shared storage assets that could be leveraged by multiple users. For example, in the near term, shared storage assets could be developed through government and industry investment in storage infrastructure such as pipelines, alongside investment in other assets, such as those related to water, ports and power generation. These shared assets may be particularly important in de-risking investments for early domestic movers as the export market develops and should take into consideration existing plans related to hydrogen hubs and Australia's National Hydrogen Strategy.[229] The domestic uptake of hydrogen is discussed further under the *Hydrogen Superpower* scenario, see Section 1.3.

Role of energy storage

There are multiple points at which energy can be stored to support hydrogen production, conversion and transportation for use domestically and internationally. Figure 32 provides an overview of potential storage points across the value chain.

Hydrogen production

Electricity storage can help underpin the continuous production of hydrogen, whether it is deployed in islanded systems dedicated to hydrogen production or on the grid to support grid-connected hydrogen production. The magnitude of electricity storage will depend on how value chains are optimised, subject to factors such as electricity prices, and the cost of hydrogen storage.

Analysis of hydrogen export volumes under the *Hydrogen Superpower* scenario found that using grid-connected power would place a significant load on the power system, leading to a doubling in electrical storage demand between 2020 and 2050 across the NEM (see Section 1.2). As such, a significant portion of electricity used to produce hydrogen may come from onsite VRE. An islanded site with energy from predominantly VRE may require onsite electricity storage to extend electrolyser operations. Storage systems, charged with a combination of wind, solar PV and/or CST, could allow extended operations to increase the capacity factor of the electrolysers. However, in this case there is a trade-off between the cost of storage and the cost of flexible electrolyser operation at lower capacity factors.

Although the *Hydrogen Superpower* scenario assumes polymer electrolyte membrane electrolysis is used, other approaches, such as solid oxide electrolysis are being considered for their high energy conversion efficiency. Solid oxide electrolysis requires high temperatures, as such it may be beneficial to make use of thermal storage (eTESh or CST) to maintain operations and reduce the need for continuous power. The storage options for enabling high temperature electrolysis are not covered in this section, however eTESh and CST for high-temperature process heat applications are discussed in Section 3.6.

The storage options for powering hydrogen production are not covered in this section. However, electrical applications for major grids and large-scale isolated grids are covered in Sections 3.2 and 3.3 respectively.

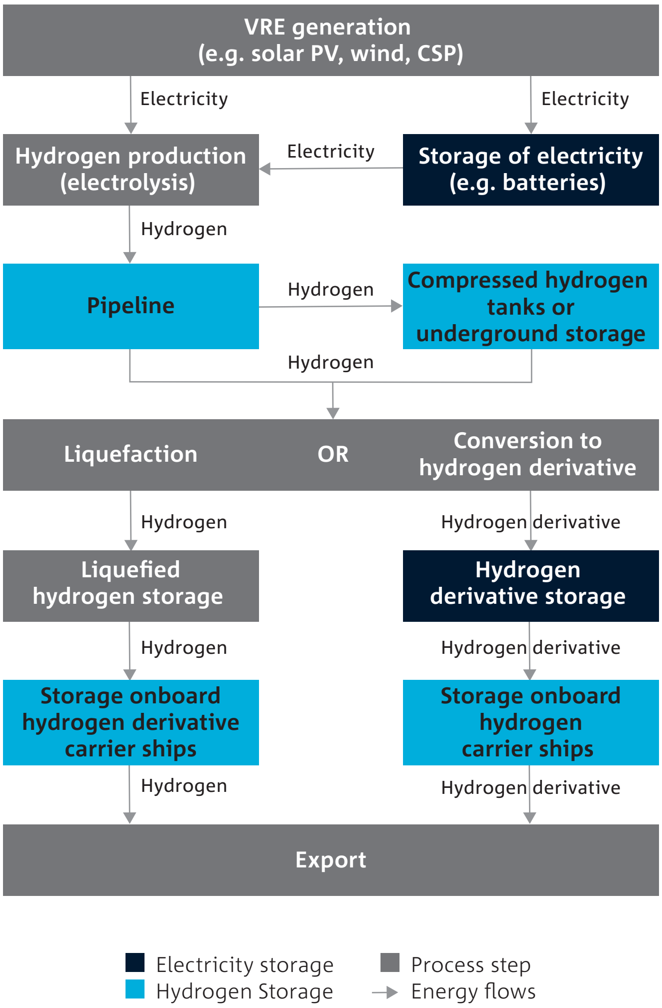
Hydrogen distribution and preparation for export

Prior to export or conversion to a hydrogen derivative, high-volume hydrogen storage may be required to buffer fluctuations in supply and demand (this is explored further in Figure 33). This storage could occur at various supply chain points, such as at the production site, liquefaction site, a derivative production facility or at a port. For example, if ammonia is being used for export, there may be a need to store hydrogen gas in tanks at an ammonia synthesis facility to ensure the plant can operate continuously. Storage along the hydrogen supply chain can also be supplemented by hydrogen pipelines. The points at which renewable electricity, compressed and liquefied hydrogen and hydrogen derivatives are stored along the export supply chain are illustrated in Figure 32.

The scale of export demand, although uncertain, will have implications for storage related to shared infrastructure assets (e.g. storage and buffering related to Australia's port infrastructure to allow for multiple ships with different docking and reloading schedules).

229 Taylor A (2021) Future hydrogen industry to create jobs, lower emissions and boost regional Australia. [Media release] <https://www.minister.industry.gov.au/ministers/taylor/media-releases/future-hydrogen-industry-create-jobs-lower-emissions-and-boost-regional-australia> (accessed 22 October 2022); COAG Energy Council (2019) Australia's national hydrogen strategy. <https://www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf> (accessed 22 October 2022).

Figure 32: Energy storage across the hydrogen export value chain



Terminology: PV, photovoltaic; VRE, variable renewable energy.

Deployment considerations

Storage technology deployment considerations will be informed by, and can influence, how an individual hydrogen export value chain is optimised. Although not exhaustive, this section builds on the considerations discussed in Section 3.1 to highlight specific considerations for stationary hydrogen storage deployment that may exist along various points of the export value chain.

- **Cost:** As shown in Figure 32, storage may be required at various points of the value chain. The capacity of storage required at each point varies and requires techno-economic analysis to find the least-cost configuration. Analysis of a *Low-Cost Hydrogen Storage* sensitivity illustrated that, for hydrogen production, the choice of storage system is sensitive to storage costs and affects how processes are optimised (see Appendix B).
- **Maturity:** To enable a rapid scale up of the hydrogen industry, the ability to deploy hydrogen storage infrastructure in the near term will be beneficial. Most of the hydrogen storage options discussed in this roadmap are at or near commercial stages; however, their deployment in specific contexts may require further investigation and demonstration prior to deployment at scale. There are also trade-offs between scaling up mature technologies with limited end uses in the near term versus investing in accelerating emerging technologies with a greater variety of end uses. The export pathways chosen (e.g. ammonia vs liquefied hydrogen) will also inform maturity considerations and will partly be determined by Australia's export partners and their strategic priorities.
- **Economies of scale:** Despite high initial CAPEX costs, high-capacity hydrogen storage systems may benefit from economies of scale because storing large volumes of hydrogen can help lower the unit cost of energy storage. This comes at a risk if hydrogen offtake is uncertain.
- **Modularity and scalability:** The ability to incrementally increase hydrogen storage capacity at relatively low marginal costs may help reduce the risk inherent to large-CAPEX systems, and enable gradual growth of storage as offtake demand increases. This could be beneficial in contexts such as storage buffering along certain points in the value chain, and piloting and demonstrating exports.

- **Geographical and site characteristics:** The type of hydrogen storage that can be deployed will be determined by a variety of geographical and site characteristics. This includes the availability of land, geological formations and reservoirs and the proximity storage to hydrogen production sites and key infrastructure (e.g. ports, pipelines and connection to major grids).
- **Supply chain considerations:** Consideration should be given to the scale up of associated supply chains in line with the growth of the hydrogen export industry. This includes the components and specialised materials (e.g. composite materials) required for high-pressure storage tanks, as well as the lining of hydrogen pipelines and, in some cases, underground caverns.
- **Safety and risk management:** Large quantities of hydrogen pose safety risks, and despite potentially low probability with strong management practices, the consequences can be severe. Depending on the storage option chosen, different measures may be needed to ensure safety. For example, reskilling workforces to become familiar with hydrogen and its risks will play an important role in this.

Figure 33: Hydrogen storage for export[230]

To help understand the potential scale of storage required for export, the role of storage and buffering has been explored for the final stages of a liquefied hydrogen export value chain. Liquefied hydrogen is one of the options being considered by Australia's export partners due to the ability to transport high concentrations of hydrogen per ship and because of the versatility of liquefied hydrogen in end-use markets.

The analysis considered storage requirements related to a small and large hydrogen export ship, with an assumed round trip time of 14 days. This means that, by the end of a 14-day period, the hydrogen export ship returns to port to be loaded with liquefied hydrogen.

- The analysis considered the buffering of liquefied hydrogen storage that needs to be ready at the port to fill the capacity of the ship. The quantity of hydrogen is slightly larger due to assumptions of loading loss and the use of standard tank sizes.
- The analysis also considered the amount of gaseous hydrogen that would need to be reliably supplied into the liquefaction facility.

The analysis found that to fill a small or large ship, approximately 4.2 or 14 kt liquefied hydrogen respectively would be needed to be stored as a buffer at the port. A further 270–860 t gaseous hydrogen would need to be buffered to ensure there is a reliable supply of hydrogen available to support the liquefaction process.

Although footprint was not analysed, the five to six hydrogen storage tanks identified would require considerable land alongside a port, as well as associated approvals. Similarly, the development or upgrade of pipelines would require appropriate regulatory approvals and have other commercial and environmental considerations. These requirements would increase in the case of a larger export facility servicing multiple ships.

Scenario	Ship capacity	Buffer of liquefied H_2 required at port for loading	Buffer of compressed H_2 tanks required for input to liquefaction
Small ship	50,000 m^3 (~3.5 kt H_2)	6 × 10,000 m^3 (6 × ~0.7-kt H_2 tanks)	270 t H_2
Large ship	160,000 m^3 (~11.3 kt H_2)	5 × 40,000 m^3 (5 × ~2.8-kt H_2 tanks)	860 t H_2

230 For a summary of the methodology and assumptions, see Appendix D.

Technology options

Storage technology options will vary based on how a given export value chain is optimised and while there are at or near commercial storage technologies, further development is required given the potential scale of operations and the various export value chain configurations.

This section focuses on four hydrogen storage technologies that could support export-scale needs. Storage technologies that can support the electricity needs for hydrogen production can be found in the discussion of major grids and large-scale isolated grids respectively (see Sections 3.2 and 3.3).

The technology options are not exhaustive and provide examples of the application of deployment considerations discussed earlier (summarised in Table 12). As stated, there are a wide variety of hydrogen derivatives being considered for export. While beyond the scope of this report, some of these derivatives are discussed later as alternative storage technologies.

More information on each of the technologies can be found in Sections 2.2 and Appendix E.

Compressed hydrogen tanks

Compressed hydrogen is not suitable for export, but can be used at multiple points along the hydrogen supply chain, such as at ammonia and liquefaction facilities. As mentioned earlier, conventional compressed hydrogen gas tanks used in the chemicals industry (e.g. ammonia plants) have been in use commercially for a long time and are at a high maturity. Cost and supply chain considerations for compressed hydrogen gas tanks depend on the type of pressure vessel used. For stationary storage, Type I tanks are widely used by industry and are the lowest-cost vessel; however, in cases where higher pressures are needed, Type II tanks (which are lined with composite materials and are more expensive) are used.[232] To transport hydrogen to facilities, Type III and IV tanks are used due to their lightweight properties, but these are significantly more expensive due to the composite materials used.[233] For these types of tanks, supply chain considerations include the speed of scale up of advanced composite materials relative to the growth of the hydrogen industry.

Table 12: Hydrogen export storage criteria and technologies

Consideration[231]	Compressed hydrogen tanks	Liquefied hydrogen	Hydrogen pipelines	Underground hydrogen
Maturity (CRI) in chemical storage applications	TRL 9/CRI 5–6	TRL 8–9/CRI 1–2	TRL 9/CRI 2–3	TRL 5–9/CRI 1–6 (varies based on the geographical subsystem available)
Economies of scale	Small opportunity to reduce cost per kilowatt for larger systems	Small opportunity to reduce cost per kilowatt for larger systems	Large opportunity to reduce cost per kilowatt for larger systems	Large opportunity to reduce cost per kilowatt for larger systems
Modularity and scalability	Modular Incrementally scalable (additional tanks)	Modular Incrementally scalable (additional tanks)	Not modular Capacity can be incrementally scaled through increasing pipe diameter Ability to line pack increases flexibility	Not modular Limited incremental scalability
Geographical and site characteristics	Flexible deployment Small footprint for small-scale capacities	Flexible deployment Small footprint for small-scale capacities	Distance between hydrogen production and end use is a factor	Geological requirements Moderate above-ground footprint

Terminology: CRI, commercial readiness index; TRL, technological readiness level.

231 Explanation of the criteria can be found in Deployment Considerations in Section 3.1; Sources can be found in Appendix E.

232 Barthélémy H (2012) Hydrogen storage – industrial prospectives. International Journal of Hydrogen Energy 37, 17364–17372.

233 Barthélémy H (2012) Hydrogen storage – industrial prospectives. International Journal of Hydrogen Energy 37, 17364–17372.

Liquefied hydrogen

Liquefied hydrogen is being considered for export due to its volumetric density, but requires further RD&D to bring down the cost of liquefaction and logistics, reduce boil-off losses and increase the scale (e.g. tank capacity). Although liquefied hydrogen is less mature than ammonia as an export medium, hydrogen in pure form has wider end-use applications than hydrogen derivatives (unless an additional hydrogen extraction process is undertaken). As such, it can potentially enable greater decarbonisation opportunities in the long term and avoid costs related to changing the type of storage and related infrastructure and logistics later on.[234]

For the purposes of this report, a liquefied hydrogen case study has been examined to explore the potential volumes of storage that may be required to meet export demand (see Figure 33). It found that in the case of a single large ship, five 40,000-m^3 tanks of liquefied hydrogen would be required at the port. However, in terms of liquefied hydrogen, volumes of up to 100,000 m^3 are being developed internationally.[235]

As mentioned earlier, there are safety risks associated with the large-scale storage of compressed and/or liquefied hydrogen that will require risk management protocols.

Underground hydrogen

Relative to other hydrogen storage options, underground hydrogen is a preferred option for the storage of large volumes of hydrogen, both in terms of safety and costs.[236] Due to its large capacity, underground hydrogen storage can provide seasonal storage to buffer longer-term imbalances between export supply and demand. In the context of export, underground storage could be used to store hydrogen at a distance away from the port itself, with the two connected via a hydrogen pipeline.

The applicability and maturity of this technology is highly dependent on local geology (i.e. the type of reservoirs available in the area). Underground salt caverns for chemical storage applications are at TRL 9/CRI 6 overseas, but are yet to be demonstrated under Australian conditions. Aquifers, depleted gas fields and engineered rock caverns require further RD&D (TRL 5–7/CRI 1).[237] Underground hydrogen storage has a relatively small above-ground geographical footprint, allowing for better space management compared with other large-scale hydrogen storage options.

Hydrogen pipelines

Line packing may be an option to consider for hydrogen export storage if the hydrogen production plant and the export point are far enough apart to warrant a hydrogen pipeline.[238] One of the benefits of line packing is the ability to increase storage capacity by altering the pressure of hydrogen within the pipes, and by incrementally increasing pipe diameter. As such, this storage technology is complementary because it can supplement forms of storage located along other points of the hydrogen value chain. In terms of safety, pilot trials and materials RD&D are ongoing to improve a pipeline's ability safely transport large volumes and high concentrations of hydrogen.[239]

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234 Shibata Y, Sichao K, Yoshida M, Nakamura H, Sakamoto T (2021) Study on the economics of the green hydrogen international supply chain. The Institute of Energy Economics, Japan. <https://eneken.ieej.or.jp/data/9882.pdf> (accessed 22 October 2022).

235 Shell, NASA, CB&I and the University of Houston are undertaking a project to develop liquid hydrogen tanks with target volumes between 20,000 and 100,000 m3. The target CAPEX for the 100,000-m3 tanks is less than A$250 million: Stetson N (2021) Importance of liquid hydrogen for decarbonizing the energy sector. <https://www.energy.gov/sites/default/files/2021-10/doe-perspectives-lh2.pdf> (accessed 22 October 2022).

236 Ennis-King et al. (2021) Underground storage of hydrogen: Mapping out the options for Australia. Future Fuels CRC. <https://www.futurefuelscrc.com/wp-content/uploads/FutureFuelsCRC_UndergroundHydrogenStorage2021.pdf> (accessed 22 October 2022).

237 CRI 1–2 for power and chemical storage applications of rock caverns, depleted gas fields and aquifers: IEA (2022) Global hydrogen review 2022. <https://www.iea.org/reports/global-hydrogen-review-2022> (accessed 20 October 2022).

238 Tanker trucks are often competitive for shorter distances, but costs depend on several factors, including the volume of hydrogen carried, its pressure and concentration and the level of utilisation of the distribution channel: IEA (2019) The future of hydrogen: Seizing today's opportunities. <https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf> (accessed 22 October 2022).

239 Abohamzeh E, Salehi F, Sheikholeslami M, Abbassi R, Khan F (2021) Review of hydrogen safety during storage, transmission and applications processes. Journal of Loss Prevention in the Process Industries 72, 104569.

Alternative storage technologies

Although not considered in this report, there are numerous hydrogen derivatives that can be used to store and export hydrogen:

- Ammonia is a cost-effective way to store and distribute hydrogen because it relies on existing technology, infrastructure and logistics. It also has a higher energy density than liquefied hydrogen. Key export partners are exploring the long-term benefits and trade-offs of investing in ammonia export at scale compared with liquefied hydrogen. Ammonia can enable the scale up of hydrogen export sooner because it uses mature technology; however, there are fewer end-use applications for ammonia (compared with pure hydrogen) unless costly hydrogen extraction and purification processes are undertaken.[240]
- Liquid organic hydrogen carriers are also being considered as an export option. For example, the University of Queensland, Nippon Oil & Energy Corporation, Chiyoda Corporation and the University of Tokyo partnered to pilot production of methylcyclohexane, which was then shipped to Japan, where the hydrogen was extracted for use.[241]
- Metal hydrides are also being piloted for export. One project considers the production of hydrogen in South Australia and transport in the form of metal hydrides to power fuel cells and other applications in the Asia Pacific region.[242]

240 Shibata et al. (2021) Study on the economics of the green hydrogen international supply chain. The Institute of Energy Economics, Japan. <https://eneken.ieej.or.jp/data/9882.pdf> (accessed 22 October 2022).

241 JTXG Nippon Oil & Energy, Chiyoda Corporation, The University of Tokyo, University of Queensland (2019) Succeeded in the world's first technical verification to produce 'CO_2-free hydrogen' at low cost. [Press release] <https://www.chiyodacorp.com/media/190315_e.pdf> (accessed 23 November 2022); Arias J (2019) Hydrogen and fuel cells in Japan. EU-Japan Centre for Industrial Cooperation. <https://www.eu-japan.eu/sites/default/files/publications/docs/hydrogen_and_fuel_cells_in_japan.pdf> (accessed 23 November 2022).

242 Global Environment Centre Foundation, Japan (2021) Pilot project for comprehensive support throughout the whole hydrogen supply chain abroad. <https://gec.jp/category/hydro/> (accessed 23 November 2022).

3.8 Transport: Heavy-duty hydrogen vehicles

Hydrogen storage could play a key role in decarbonising heavy-duty vehicles, as FCEVs are expected to become increasingly competitive for high load, long range operations requiring short recharging times. A reliable hydrogen refuelling network will require hydrogen storage at various points along the distribution system. Storage choices will be based on the optimal distribution model to service a given area and should consider opportunities to leverage shared hydrogen assets, such as large-scale hydrogen production and storage at hubs.

The transport sector was responsible for 18% of Australia's greenhouse gas emissions in 2020, with 47% of these emissions produced by light passenger vehicles, 21% by medium- and heavy-duty road freight and 11% by domestic aviation and shipping.[243]

The two primary pathways being considered for decarbonising Australia's road transport sector are electrification and hydrogen (or a derivative), with both being considered for light and heavy vehicles. For heavy road transport specifically, hydrogen is expected to become more competitive for long-range operations requiring short recharging times.[244]

	TRANSPORT: HEAVY-DUTY HYDROGEN VEHICLES Storage of hydrogen (as an example of large and distributed chemical energy storage) to support export and transport
Electrochemical	*
Mechanical	*
Chemical	✓
Thermal	

✓ Technology options explored in section

* Technology applies but not discussed in chapter, cross reference to other sections

243 Climate Change Authority (2021) Fact sheet: Transport. <https://www.climatechangeauthority.gov.au/sites/default/files/2021-03/2021Fact%20sheet%20-%20Transport.pdf> (accessed 13 September 2022).

244 IRENA (2022) Geopolitics of the energy transformation: The hydrogen factor. <https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jan/IRENA_Geopolitics_Hydrogen_2022.pdf> (accessed 22 October 2022).

To manage scope, this section focuses on stationary storage applications to support hydrogen-based transport applications, with a particular focus on heavy-duty vehicles. As such, it does not cover onboard (or in-vehicle) storage. It is important to note that the electrification of vehicles will have stationary storage considerations that largely relate to the electricity grid, with a few exceptions discussed at the end of this section (see Figure 35). Further, specialised vehicles, such as haul trucks on mine sites, were not included in the scope, but both hydrogen and electrification are being considered as options. This has implications for hydrogen storage on mine sites and large isolated mining grids, including opportunities for vehicles to share the storage infrastructure used to support other onsite operations.

Hydrogen demand from commercial fleets of heavy-duty vehicles and their use of 'back-to-base' commercial transport routes make them a target market for hydrogen refuelling stations (HRS) demonstration and scale up.[245] A 2020 market study for hydrogen use in Australia analysed potential transport end-use applications and deemed four to be commercially viable or expected to approach commercial viability by 2030. These were typically used in medium- to heavy-duty transport: line haul vehicles, mining vehicles, return-to-base vehicles (e.g. buses) and vehicles for materials handling.[246] Energy storage will play a key role at fuelling stations and across the distribution network, similar to the storage and buffering at traditional fuel stations. However, the model and structure of the distribution network require careful consideration and are major determinants of the type of energy storage system that will be required.

Role of energy storage

Creating a reliable fuel storage and refuelling network that facilitates hydrogen adoption necessitates a coordinated rollout of refuelling clusters[247] and standalone HRS along corridors,[248] each with sufficient energy storage capabilities to meet customer demands.[249]

HRS will require their own onsite hydrogen storage capabilities. In addition to onsite storage, the method of hydrogen delivery to individual refuelling sites can have implications for the type of storage system deployed and the reliability of the broader refuelling network. Three distribution models are being actively considered; each of these requires hydrogen storage along different points of the refuelling distribution network (illustrated in Figure 34).

- **Hub-and-spoke model:** A hub-and-spoke model operates with a central point of hydrogen production that distributes the hydrogen to sites beyond where it is produced, including refuelling stations, to develop comprehensive refuelling networks. Industry consultations and international examples indicate that hub-and-spoke models are likely to be the more viable distribution pathway compared with pipelines and the onsite production of hydrogen due to costs and technical barriers.
- **Onsite hydrogen production:** Onsite hydrogen stations may be equipped with infrastructure to produce hydrogen via electrolysis.
- **Mobile/portable hydrogen refuelling:** Mobile hydrogen refuelling infrastructure involves a hydrogen storage tank that is filled at a hydrogen production facility and towed to refill vehicles at another site when needed. A portable HRS involves a semipermanent structure with a compressor and dispenser, but can be moved to another site.

245 Bruce S, Temminghoff M, Hayward J, Schmidt E, Munnings C, Palfreyman D, Hartley P (2018) National hydrogen roadmap. CSIRO, Australia.

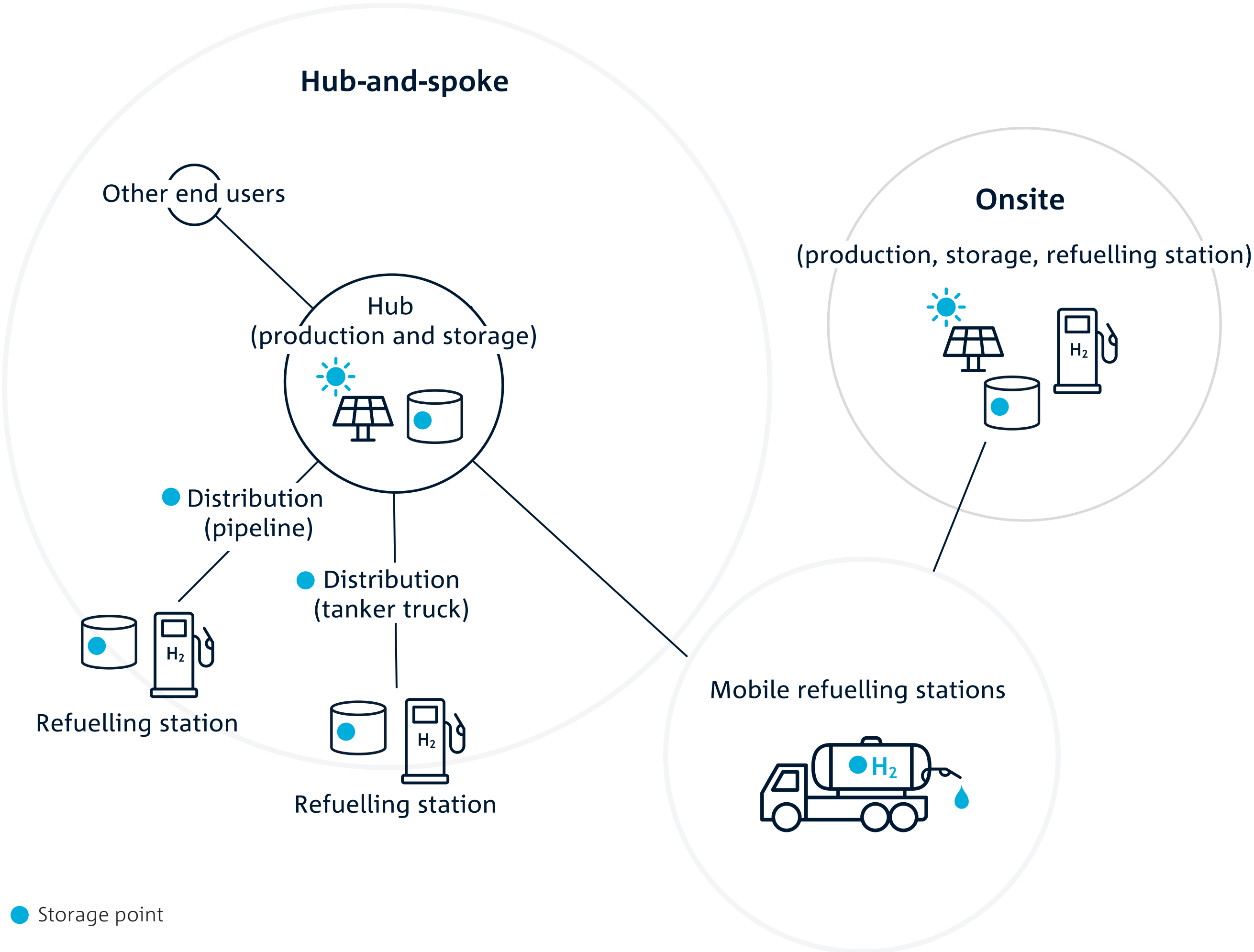
246 Advisian (2021) Australian hydrogen market study: Sector analysis summary. <https://www.cefc.com.au/media/nhnhwlxu/australian-hydrogen-market-study.pdf> (accessed 4 July 2022).

247 'Clusters' describes the distribution of refuelling stations within a limited geographical area where there is expected to be a large portion of fuel cell EV customers.

248 'Corridors' refer to a distribution of refuelling stations spanning a broad geographical area, enabling customers to move freely between clusters and to have their needs serviced.

249 Isenstadt A, Lutsey N (2017) Developing hydrogen fueling infrastructure for fuel cell vehicles: A status update. The International Council on Clean Transportation. <https://theicct.org/sites/default/files/publications/Hydrogen-infrastructure-status-update_ICCT-briefing_04102017_vF.pdf> (accessed 4 July 2022).

Figure 34: Storage points along the hydrogen refuelling network



Deployment considerations

The type of refuelling model is a key determinant for the type of energy storage system deployed in the context of vehicle refuelling. Although not exhaustive, this section builds on the considerations discussed in Section 3.1 to highlight specific stationary storage deployment considerations associated with each distribution model, namely the hub-and-spoke model, refuelling stations with onsite hydrogen production capabilities and portable/mobile refuelling systems.

- **Cost:** In the context of refuelling networks, the cost of individual hydrogen storage technologies cannot be looked at in isolation. Rather, the entire distribution model must be taken into consideration, including the overall costs of all the storage points along the system, as well as distribution infrastructure and logistics costs. The storage system chosen will depend on how the distribution network is optimised.
- **Maturity:** To enable the rapid scale up of hydrogen use in the transport sector, the ability to deploy hydrogen storage infrastructure in the near term will be beneficial. Most of the hydrogen storage options discussed in this roadmap are at or near commercial stage, but deployment in the context of refuelling networks requires further analysis and demonstration at scale in Australia, particularly with respect to integrating storage systems with refuelling infrastructure, distribution infrastructure and logistics.
- **Economies of scale:** Large-scale hydrogen storage systems at hydrogen hubs benefit from economies of scale because storing large volumes of hydrogen can help lower the per-unit cost of energy storage. Further, the shared use of hydrogen production and storage assets by other end users (e.g. industry and export) creates a broader value proposition for investment in large-scale hydrogen storage. Considerations when deploying large-scale hydrogen storage include the breadth and location of potential transport and other end users.
- **Modularity and scalability:** Areas with high and frequent refuelling demands will require stations in clusters to be capable of handling increasing numbers of vehicles with increased hydrogen capacity and should be amenable to upgrades.[250] In such cases, storage systems that can incrementally increase capacity over time are beneficial. HRS with onsite hydrogen production capabilities are likely to use tank-based storage. These stations can vary markedly in size depending on the scale of hydrogen generation.[251] Because of this, modular storage designs that can be scaled as demand increases can help mitigate fuel supply risk.[252] Mobile refuelling stations require modular forms of storage (and associated refuelling equipment) in order to be flexibly located and utilised (including for emergency refuelling of heavy-duty transport).

250 Isenstadt A, Lutsey N (2017) Developing hydrogen fuelling infrastructure for fuel cell vehicles: A status update. The International Council on Clean Transportation. <https://theicct.org/sites/default/files/publications/Hydrogen-infrastructure-status-update_ICCT-briefing_04102017_vF.pdf> (accessed 4 July 2022).

251 Ehrhart BD, Bran Anleu GA, Ye D, Hecht E, Muna AB, LaFleur CB. Hydrogen stations for urban sites. <https://www.osti.gov/servlets/purl/1570553> (accessed 22 October 2022).

252 Bruce et al. (2018) National hydrogen roadmap. CSIRO, Australia.

- **Geographical and site characteristics:** The location and availability of land can limit the storage systems that can be deployed. For example, in the case of refuelling stations with limited space, modular and stackable systems may be required to meet buffering capacities. With respect to hub-and-spoke models, the availability of water and geological storage sites may dictate where hydrogen hubs and associated storage can be located. Further, the distances between production sites and refuelling stations may dictate whether pipeline storage is used or whether tanker trucks are used with greater buffering at distribution points.
- **Safety and risk management:** In the context of refuelling, safety will need to be considered for all storage types used across the distribution system and in the transmission and handling processes. In terms of storage, this includes the materials of the tanks and pipelines being used and their resistance to hydrogen, fire and other types of damage, temperature variations and leakages.[253]
- **Onsite storage capacity at stations:** For refuelling stations, the expected vehicle demand in the serviceable area partly determines the onsite storage capacity required (e.g. number of vehicles, frequency of refuelling, vehicle capacity and distances between refuelling stations). The storage capacity required onsite also depends heavily on the configuration and optimisation of the distribution network. For example, if hydrogen is distributed via tanker truck, stations will likely require buffering storage onsite, and capacity will depend on the frequency and capacity of the tanker trucks. If hydrogen is supplied continuously from a hub via a pipeline, this will reduce the buffering capacity required onsite. If hydrogen is produced onsite, this will also require onsite storage.
- **Vehicle type:** The most mature fuel cell vehicle technologies use high-pressure in-vehicle storage of 350 or 700 bar. Depending on their target vehicle base, stations can be equipped to service one pressure or be equipped with dual refuelling pressures to service both types of vehicles (350 or 700 bar). Stations may consider dual refuelling pressures to futureproof for growth in customer base and the types of vehicles that could be serviced. Although fuel cell vehicles are the predominant hydrogen vehicle type, hydrogen internal combustion engine vehicles are being considered due to the benefits of modifying existing equipment.[254] This will have implications for the choice of storage (and dispensing equipment) at the refuelling site and may impact the type of storage upstream, as well as distribution network configuration. For heavy-duty and long-haul trucking, the energy density of fuel is advantageous for reducing weight onboard and minimising refuelling time. As new fuels are explored, related storage will need to be taken into account.

253 Abohamzeh et al (2021) Review of hydrogen safety during storage, transmission, and applications processes. Journal of Loss Prevention in the Process Industries 72, 104569.

254 IEA (2022) Global hydrogen review 2022. <https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf> (accessed 20 October 2022); Cummins (2022) Cummins to reveal zero-carbon H2-ICE concept truck at IAA Expo powered by the B6.7H hydrogen engine. [Media release] <https://www.cummins.com/news/releases/2022/09/13/cummins-reveal-zero-carbon-h2-ice-concept-truck-iaa-expo-powered-b67h> (accessed 22 October 2022).

Technology options

Storage choices will be based on the optimal distribution model, and this will depend on the development of large-scale hydrogen production, end use clusters and shared infrastructure. This section focuses on five hydrogen energy storage options to support the refuelling needs of Australia's heavy-duty transport sector.

The technology options are not exhaustive and provide examples of the application of deployment considerations discussed above (summarised in Table 12). For example, beyond hydrogen, there are a number of alternative low-carbon fuels that can support industry-wide decarbonisation (see Alternative technologies).

More information on each of the technologies can be found in Part II (see Section 2.2) and Appendix E.

Underground hydrogen

There are multiple supported commercial examples of underground hydrogen storage systems in the chemical sector globally, and these are now being demonstrated in the context of emerging end uses. With regard to a hub-and-spoke model, there may be an opportunity for underground hydrogen to support bulk hydrogen storage at a 'hub' prior to distribution. Mass storage of hydrogen in an underground cavern creates economic opportunities to supply to co-located industries (refer to Section 3.7) and creates a broader value proposition for the investment in hydrogen generation and storage infrastructure.

As discussed earlier, the deployment of underground hydrogen for bulk storage will depend on the availability of appropriate geological underground landforms. It is unlikely that underground geological storage would be a viable storage option for individual refuelling stations due to their scale and geological requirements.

Hydrogen pipelines

Hydrogen pipelines are being considered as a storage and distribution method for transport applications and are currently at TRL 9/CRI 3. If used, a pipeline system can mitigate the need for onsite hydrogen storage because the hydrogen can be passed directly through a compressor prior to being dispensed (hydrogen delivered via a pipelines is usually low pressure, ~20 bar).[255,256] The costs of hydrogen pipelines need to be compared to the costs of delivering hydrogen via trucks and storing hydrogen onsite in order to determine the lowest-cost route. Due to the high upfront capital costs for construction, new pipelines are typically only considered in regions where there is substantial demand that is expected to remain relatively stable for decades. Blended gas networks are also being considered and are a lower-cost alternative to new hydrogen pipelines, however for transport applications, hydrogen extraction and purification would be required at offtake locations, which increases CAPEX and OPEX costs.[257] Refuelling stations may also be required to repressurise hydrogen prior to storage and dispensing if the distance between the production site and the HRS causes a pressure drop. Further RD&D is required to support the establishment of standards for hydrogen pipeline networks in Australia, including the resistance of pipeline materials to hydrogen.

Compressed hydrogen tanks

Gaseous hydrogen storage is the most widely used and most mature storage option for onsite storage at refuelling stations. Although compressed hydrogen is a commercially mature storage option, its integration at refuelling stations requires further improvements to improve costs and efficiency, and to increase refuelling speeds.

255 H_2 Mobility. Overview: Hydrogen refuelling for heavy duty vehicles. <https://h2-mobility.de/wp-content/uploads/sites/2/2021/08/H2-MOBILITY_Overview-Hydrogen-Refuelling-For-Heavy-Duty-Vehicles_2021-08-10.pdf> (accessed 22 October 2022).

256 Reddi K, Mintz M, Elgowainy A, Sutherland E (2016) 13 – Building a hydrogen infrastructure in the United States. In Compendium of hydrogen energy, Volume 4: Hydrogen use, safety and the hydrogen economy. Woodhead Publishing Series in Energy. (Eds Ball M, Basile A, Veziroğlu TN) 293–319. Woodhead Publishing. doi:10.1016/B978-1-78242-364-5.00013-0

257 H_2 Mobility. Overview: Hydrogen refuelling for heavy duty vehicles. <https://h2-mobility.de/wp-content/uploads/sites/2/2021/08/H2-MOBILITY_Overview-Hydrogen-Refuelling-For-Heavy-Duty-Vehicles_2021-08-10.pdf> (accessed 22 October 2022); Wickham D, Hawkes A, Jalil-Vega F (2022) Hydrogen supply chain optimisation for the transport sector – focus on hydrogen purity and purification requirements. Applied Energy 305, 117740.

With regard to delivery, storage and transportation, compressed hydrogen is considered to be a cost-effective option for shorter distances or areas with lower overall demand.[258] Hydrogen can be pressurised and stored onsite at any pressure (e.g. 200–400 bar).[259] It can also be delivered by tanker truck at various pressures (e.g. 180–500 bar).[260] Hydrogen must go through further compression of up to 1,000 bar before it is dispensed into a vehicle (fuel cell vehicles typically store hydrogen onboard at a pressure of 350 or 700 bar, so dispensing pressure must be slightly higher).[261]

Compressed hydrogen for buffering is typically stored in above-ground vessels, with the ability to stack additional vessels to increase capacity in line with demand. Although these systems do not come with the economies of scale of large-scale underground systems, they can be used at hydrogen hubs. HRS with onsite hydrogen production capabilities are likely to use compressed tank-based storage with modular and scalable storage designs.

For HRS with EV charging capabilities, there must be sufficient space between hydrogen storage/refuelling and battery charging in compliance with safety regulations and protocols. Consideration must also be given to how much hydrogen is being stored onsite, the materials used and their resistance to damage, temperature variations arising from fast-filling configurations and leakages.[262]

Liquefied hydrogen

Liquefied hydrogen is a well-established technology, commonly transported and delivered via tanker trucks.[263] In the context of transport, liquefied hydrogen is an emerging option being considered for storage at HRS[264] because it allows hydrogen to be transported in a more energy-dense state. In this case, stationary cryogenic storage vessels will be required onsite at HRS to accommodate new vehicle deployments. The systems also differ in how they are deployed (i.e. above or below ground), and in their technical storage parameters (i.e. pressures, temperatures, volumes etc.).

Challenges include the costs associated with liquefying hydrogen and keeping it in a liquid state (due to the energy required to maintain low temperatures). Although mature, longer transportation times can lead to evaporation as heat enters the storage tanks. To minimise these losses, tanks require greater insulation.[265] It is unlikely that hydrogen stations with onsite production would also liquefy and store hydrogen in its liquefied form, given the additional costs on top of the costs of electrolysis.[266]

258 European Commission (2021) Assessment of hydrogen delivery options. Science for Policy Briefs. <https://joint-research-centre.ec.europa.eu/system/files/2021-06/jrc124206_assessment_of_hydrogen_delivery_options.pdf> (accessed 22 October 2022); Rodel A, Wulf C, Kaltschmitt M (2018) Chapter 3. Assessment of selected hydrogen supply chains – factors determining the overall greenhouse gas emissions. In Hydrogen supply chains. (Ed. C Azzaro-Pantel) 81–109. Academic Press. doi:10.1016/B978-0-12-811197-0.00003-8

259 Reddi et al. (2016) 13 – Building a hydrogen infrastructure in the United States. In Compendium of hydrogen energy, Volume 4: Hydrogen use, safety and the hydrogen economy. Woodhead Publishing Series in Energy. (Eds Ball M, Basile A, Veziroğlu TN) 293–319. Woodhead Publishing. doi:10.1016/B978-1-78242-364-5.00013-0

260 U.S. Department of Energy (2022) Hydrogen tube trailers. <https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers> (accessed 22 October 2022).

261 Bruce et al. (2018) National hydrogen roadmap. CSIRO, Australia.

262 Abohamzeh et al. (2021) Review of hydrogen safety during storage, transmission and applications processes. Journal of Loss Prevention in the Process Industries 72, 104569.

263 U.S. Department of Energy (n.d.) Liquid hydrogen delivery. <https://www.energy.gov/eere/fuelcells/liquid-hydrogen-delivery> (accessed 22 October 2022); Burke A, Fulton L (2022) Use of liquid hydrogen in heavy-duty vehicle applications: Station and vehicle technology and cost considerations. <https://escholarship.org/content/qt22z8260f/qt22z8260f_noSplash_471a1fd55d7f6bc82febb5e5897f7b4c.pdf> (accessed 22 October 2022); TüV Nord (n.d.) Hydrogen storage: Overview of possibilities. <https://www.tuev-nord.de/en/company/energy/hydrogen/hydrogen-storage/> (accessed 22 October 2022); H_2 Mobility. Overview: Hydrogen refuelling for heavy duty vehicles. <https://h2-mobility.de/wp-content/uploads/sites/2/2021/08/H2-MOBILITY_Overview-Hydrogen-Refuelling-For-Heavy-Duty-Vehicles_2021-08-10.pdf> (accessed 22 October 2022).

264 Burke A, Fulton L (2022) Use of liquid hydrogen in heavy-duty vehicle applications: Station and vehicle technology and cost considerations. <https://escholarship.org/content/qt22z8260f/qt22z8260f_noSplash_471a1fd55d7f6bc82febb5e5897f7b4c.pdf> (accessed 22 October 2022); Hy Responder (2021) European train the trainer programme for responders. Lecture 12: Hydrogen refuelling stations & infrastructure. <https://hyresponder.eu/wp-content/uploads/2021/06/L12_HyResponder_L4_210622.pdf> (accessed 22 October 2022); H_2 Mobility. Overview: Hydrogen refuelling for heavy duty vehicles. <https://h2-mobility.de/wp-content/uploads/sites/2/2021/08/H2-MOBILITY_Overview-Hydrogen-Refuelling-For-Heavy-Duty-Vehicles_2021-08-10.pdf> (accessed 22 October 2022).

265 Bruce et al. (2018) National hydrogen roadmap. CSIRO, Australia.

266 Bruce et al. (2018) National hydrogen roadmap. CSIRO, Australia; Ehrhart et al. Hydrogen stations for urban sites. <https://www.osti.gov/servlets/purl/1570553> (accessed 22 October 2022).

Metal hydrides

Hydrogen can be stored in a 'solid state' using metal hydrides. Although large-scale metal hydride systems could support storage at refuelling sites, this has not yet been demonstrated. The technology has been investigated for its storage ability onboard vehicles, which could reduce hydrogen dispensing costs for station operators.[267] Further, given that hydrogen compression is a key contributor to capital and operation costs of hydrogen refuelling infrastructure, metal hydrides can offer an alternative to mechanical compressors through a reversible thermal reaction. Although metal hydrides are still being demonstrated at pilot scales (TRL 8–9/CRI 2), this technology is promising for stations that have existing pipeline infrastructure.[268] This metal hydride compression technology has been showcased by Impala Platinum refineries in South Africa, with the refuelling station under operation since 2015.[269]

Alternative technologies

Although not considered in this report, several other hydrogen derivatives can be used for storage to support transport applications. For example:

- **Green methanol** (MeOH) can be used as a drop-in fuel and can be synthesized from CO_2 (which can be obtained via carbon capture and utilisation processes) and green hydrogen. Although some CO_2 is released during combustion, the level is low compared with conventional fuels.[270] MeOH is already used in light- and heavy-duty transportation and being considered for maritime applications. MeOH is generally stored in above-ground tanks constructed from carbon steel or austenitic stainless steel.
- **Ammonia** has a higher energy density than hydrogen, making it easier and less costly to transport. Although there are no vehicle fleets operating that are currently 100% fuelled by ammonia, using ammonia as a fuel has been under investigation by researchers.[271] Ammonia is generally stored at atmospheric pressure at –33°C. Hybrid storage tanks that can support the transition from liquefied natural gas to ammonia are also under investigation.[272]

267 Frank ED, Elgowainy A, Khalid YS, Peng J-K, Reddi K (2019) Refueling-station costs for metal hydride storage tanks on board hydrogen fuel cell vehicles. International Journal of Hydrogen Energy 44, 29849–29861.

268 Lototskyy M, Davids MW, Swanepoel D, Louw G, Klochko Y, Smith Y, Haji Y, Tolj I, Chidziva S, Pasupathi S, Linkov V (2020) Hydrogen refuelling station with integrated metal hydride compressor: Layout features and experience of three-year operation. International Journal of Hydrogen Energy 45, 5415–5429.

269 Implats (n.d.) Harnessing PGMs for fuel cell technology. <https://www.implats.co.za/stories/Harnessing-PGMs-for-fuel-cell-technology.php> (accessed 22 October 2022).

270 EIBIP (n.d.) Methanol fuel. <https://eibip.eu/publication/methanol-fuel/> (accessed 22 October 2022).

271 Mounaïm-Rousselle C, Brequigny P (2020) Ammonia as fuel for low-carbon spark-ignition engines of tomorrow's passenger cars. Frontiers in Mechanical Engineering. doi:10.3389/fmech.2020.00070

272 Black & Veatch (n.d.) Designing ammonia-ready LNG storage tanks. <https://www.bv.com/perspectives/designing-ammonia-ready-lng-storage-tanks> (accessed 22 October 2022).

Figure 35: Additional stationary storage considerations for EVs

While this section is focused on the use of hydrogen for heavy-duty and long-haul vehicles, the adoption of electric vehicles have large implications for the energy system. They are expected to provide storage capacity to the grid, households or businesses, but will also require electricity for charging, with implications for electricity infrastructure and grid-side storage.

The majority of electric vehicles are likely to be light-passenger and medium-duty vehicles. However, electrification is also being considered for heavy-duty and long-haul vehicles and there are several trails and innovative projects underway, for example the electrification of haul trucks in mining.[273]

From an EV recharging infrastructure perspective, additional stationary storage may be required depending on where charging is occurring, with varying implications:

- **Grid-connected charging:** In most cases, charging infrastructure will be grid connected. This could require management systems and appropriate tariff structures to support the fast charging of multiple vehicles at any one time. In some cases, grid augmentation to increase voltage and capacity may be required; however, charging stations can be strategically located where loads can be supported by the infrastructure in place. Part I of this report discusses the grid-side demand for energy storage with underlying assumptions about EV rollout. For more information on technology options and considerations for grid-side electrical storage, refer to Section 3.2.
- **Off-grid charging:** Isolated areas can benefit from onsite generation and energy storage to power their EV charging stations. Alternative business models being considered for isolated EV applications include battery-swapping models (where batteries are pre-charged at a battery-swapping station and swapped with the discharged vehicle battery to reduce vehicle charging time) and catenary lines (cables connecting heavy electrified transport to power on mine sites and road corridors). In these deployment scenarios, sites will likely need to make use of shared electrical and storage assets because this can significantly reduce the overall costs of generation and storage. For more information on electrical storage in large- and small-scale isolated grids, see Sections 3.3 and 3.4 respectively.
- **Hybrid grid–onsite storage solutions:** In some grid-connected locations, on-station storage may be required to supplement the connection to support charging loads. Although this is a niche application, this scenario can occur in fringe-of-grid, regional or remote charging stations that have a low-voltage grid connection. Although these locations may experience a lower demand, on average, due to fewer vehicles, high maximum-demand events (where multiple vehicles arrive to charge at the same time) can render grid-supplied electricity prohibitively expensive. Aside from reviewing pricing structures, an onsite storage system may be an option to smooth out maximum-demand events. This can also be used as a shared storage asset for community power or site operations to increase utilisation and further bring down storage costs. Although fringe-of-grid areas are not explored in this report, they face similar challenges to large- and small-scale isolated grids in terms of high electricity costs and unreliable power supply. For more information on electrical storage in large- and small-scale isolated grids, see Sections 3.3 and 3.4 respectively.

273 OZ Minerals (2022) Janus, Qube and OZ Minerals partnering for a zero emissions future – vision electric. [Media release] <https://www.ozminerals.com/en/news/media-releases/2022-media-releases/janus-qube-and-oz-minerals-partnering-for-a-zero-emissions-future-vision-electric> (accessed 24 November 2022); Charge on Innovation Challenge (2022) Winning technology innovators announced. News. <https://chargeoninnovation.com/winning-technology-innovators-announced/> (accessed 24 November 2022)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Part IV: Strategic priorities for energy storage

Australia will need to rapidly invest in a pipeline of projects across a portfolio of energy storage technologies, supported by market and ecosystem development, in order to address challenges and realise opportunities across its diverse sector applications and rapidly evolving energy system.

Australia's evolving energy system will require additional renewable energy storage capacity to support the energy transition and provide a reliable, secure and cost-effective supply of energy. However, the scenarios, sectors and technologies analysed in this report highlight several technology gaps and risks in meeting future storage demand. This is due, in part, to the limited set of commercially mature storage options and their inherent constraints and risks based on end-use applications, and is compounded by the fact that today's decisions relating to decarbonisation will alter the scale and type of storage required to 2030 and beyond.

Strong collaboration will be required across government, industry and research institutions to address these gaps and risks. Concerted effort will help to ensure that Australia has the right market settings, develops a portfolio of energy storage technologies to meet diverse end-user needs, and takes advantage of broader local and global ecosystems to avoid duplication of investment.

This section synthesises insights from the report analysis and stakeholder consultations into an action plan for scaling up renewable energy storage in Australia, while acknowledging various uncertainties remain regarding future storage demand and end user requirements.

Figure 36: Strategic priorities for energy storage

Energy market considerations

Near-term energy market design decisions will shape the course of Australia's storage-related needs and investments, requiring further consideration and planning.

Technology recommendations

Australia will need to rapidly develop a pipeline of projects across a portfolio of energy storage technologies to address key technology challenges across different end-use applications and geographic locations.

Ecosystem recommendations

Greater levels of domestic and international engagement can help Australia establish supply chains and de-risk and reduce the cost of renewable energy storage deployment.

4.1 Energy market considerations

Near-term energy market design decisions will shape the course of Australia's storage-related needs and investments, requiring further consideration and planning.

As new energy storage technologies increase in commercial readiness and new business models are introduced to the market, policy and regulatory frameworks will need to evolve to optimise the energy system, underpinned by an efficient mix of energy storage deployments.

Market reforms and research and analysis into the design of Australia's future electricity market are currently underway. In 2022 a national level Capacity Investment Scheme was announced to support a mix of renewable dispatchable storage and generation.[274] Australia's Energy Security Board (ESB) proposed a set of reforms to provide an efficient mix of generation, storage and demand response to replace aging thermal generation, provide essential system services and integrate increasing distributed energy resource assets.[275] A program of work is currently underway to deliver the reforms in consultation with industry and consumer stakeholders.[276]

The National Energy Transformation Partnership will also undertake actions on items such as market mechanisms to ensure storage adequacy in consultation with industry and community stakeholders.[277] ARENA has funded a study on energy storage market design led by Monash University's Grid Innovation Hub looking at incentive design and improved valuation of energy storage services.[278] In WA, ARENA funded a distributed energy resources orchestration pilot led by Western Power looking at the integration of VPPs into the SWIS, including both the technical aspects and the valuation of services to inform future market design.[279] Concurrent work is also being undertaken internationally by governments and industry groups that can support knowledge sharing and inform best practice.

It is beyond the scope of this report to analyse market reforms and regulatory frameworks. However, given their importance, this section summarises key considerations from Australian and international publications and stakeholder consultations. Although largely related to the electricity market, non-electricity considerations have been included in the context of thermal and chemical storage where relevant. The list of considerations is provided in Table 13 and are not exhaustive.

Table 13: Energy market considerations

CATEGORY	CONSIDERATION
Storage specifications	Specifications for storage across grants, tenders, standards and regulations are often framed in terms of technology type (e.g. batteries) or its role (e.g., generation asset, or load-modifying resource).[280,281] This limits the scope of technologies that could be considered to meet end-user needs across sectors. Greater collaboration may be required to identify and amend terms of reference that may create unintended biases and reduce competition. Example considerations include: • Multistakeholder engagement to develop **technology-agnostic specifications** for storage in terms of end-user technical, energy and safety requirements, to eliminate unintended biases and create a fair and competitive playing field among technologies. • **Treatment of storage assets in regulatory frameworks** as a distinct asset type from generation assets. This will also require careful treatment of assets such as CST, which is both a generation and storage asset.

274 Hon Chris Bowen (2022) Capacity Investment Scheme to power Australian energy market transformation. Media releases. Department of Climate Change, Energy, the Environment and Water <https://minister.dcceew.gov.au/bowen/media-releases/capacity-investment-scheme-power-australian-energy-market-transformation>

275 ESB (2021) Post-2025 market design: Final advice to energy ministers. Part A. <https://www.energy.gov.au/sites/default/files/2021-10/Post%202025%20Market%20Design%20Final%20Advice%20to%20Energy%20Ministers%20Part%20A_0.pdf> (accessed 24 October 2022).

276 ESB (2022) Post 2025 electricity market design. <https://esb-post2025-market-design.aemc.gov.au/> (accessed 24 October 2022).

277 Department of Climate Change, Energy, the Environment and Water (2022) National Energy Transformation Partnership. <https://www.energy.gov.au/government-priorities/energy-ministers/priorities/national-energy-transformation-partnership> (accessed 24 November 2022).

278 ARENA (2022) Monash University integrating energy storage into the NEM study. <https://arena.gov.au/projects/monash-university-integrating-energy-storage-into-the-nem-study/> (accessed 24 October 2022).

279 ARENA (2021) Western Australia distributed energy resources orchestration pilot (Project Symphony). <https://arena.gov.au/projects/western-australia-distributed-energy-resources-orchestration-pilot/> (accessed 24 October 2022).

280 LDES Council (2022) The journey to net-zero: An action plan to unlock a secure net-zero power system. <https://www.ldescouncil.com/assets/pdf/journey-to-net-zero-june2022.pdf> (accessed 24 October 2022).

281 LDES, McKinsey & Company (2021) Net-zero power: Long-duration energy storage for a renewable grid. <https://www.mckinsey.com/capabilities/sustainability/our-insights/net-zero-power-long-duration-energy-storage-for-a-renewable-grid> (accessed 24 October 2022).

CATEGORY	CONSIDERATION
Valuing and incentivising energy storage services	Storage incentives should be designed to achieve a low-cost, reliable and secure energy system and should be aligned to the value of the services delivered by the storage asset. Market mechanisms that provide long-term market signals or revenue streams can offer investors and technology proponents greater certainty as to the commercial viability of their storage asset.[282,283] Other more direct forms of support (e.g. targets and tenders) can help incentivise more immediate implementation of energy storage projects. These incentives should be considered across electricity, thermal and chemical storage. Example considerations include: • The identification, design and implementation of effective incentives beyond the short-duration revenue stacking options of FCAS and price arbitrage mechanisms. This includes **valuation and revenue stacking opportunities** for medium-, long- and seasonal-duration storage systems and valuation of hybrid systems that use multiple types of storage to provide a suite of system services. • **Regular review of potential disincentives** that exist in the storage market. A common example cited in stakeholder consultations is the manner in which network charges are imposed on energy storage assets. Although market design is essential for providing long-term certainty, it can involve a lengthy engagement process. • Mechanisms that can be implemented in shorter time frames, such as **targets and tenders**, to help achieve immediate objectives. For example, Victoria has legislated a target of 2.6 GW renewable energy storage capacity by 2030[284] and NSW has announced a long-duration storage target of 2 GW (in addition to Snowy 2.0) by 2030,[285] in addition to starting an initial tender process expected to deliver up to 600 MW of long-duration storage.[286] • Exploration of market mechanisms to **incentivise thermal storage** applications for process heat. For example, this could include reviewing international activity related to renewable heat targets and actions to encourage fuel switching. Consideration should also be given to addressing imperfect information related to thermal storage applications in the market.[287] • **Market mechanisms for chemical storage**, namely hydrogen and its derivatives. Australia's National Hydrogen Strategy highlights incentives, policies and regulations across jurisdictions that can help support the production, storage and use of hydrogen.[288] Several countries have undertaken studies on hydrogen market frameworks and have launched early initiatives. Examples include Germany's H2Global auction-based mechanism, which has established a trade partnership with Australia,[289] and the UK's consideration of a low-carbon hydrogen business model.[290] • Incentivising solutions for **demand-side flexibility** to minimise the need for storage-related investments across the system, resulting in lower overall system costs. For example, electrified heavy industry players with flexible loads can reduce the need for grid-side storage by reducing their electricity use over periods of time to provide grid-smoothing services.[291] Remuneration for this type of demand-side response will need to consider impacts on profit margins (e.g. reduced output, increased plant maintenance costs).

282 LDES Council (2022) The journey to net-zero: An action plan to unlock a secure net-zero power system. <https://www.ldescouncil.com/assets/pdf/journey-to-net-zero-june2022.pdf> (accessed 24 October 2022).

283 LDES, McKinsey & Company (2021) Net-zero power: Long-duration energy storage for a renewable grid. <https://www.mckinsey.com/capabilities/sustainability/our-insights/net-zero-power-long-duration-energy-storage-for-a-renewable-grid> (accessed 24 October 2022).

284 Andrews D (2022) Australia's biggest renewable energy storage targets. <https://www.premier.vic.gov.au/australias-biggest-renewable-energy-storage-targets> (accessed 21 October 2022).

285 NSW Department of Planning and Environment (2020) NSW electricity infrastructure roadmap. <https://www.energy.nsw.gov.au/sites/default/files/2022-08/NSW%20Electricity%20Infrastructure%20Roadmap%20-%20Overview_1.pdf> (accessed 24 November 2022).

286 NSW Government (2022) Q4 2022 tender. <https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/electricity-infrastructure-roadmap/q4-2022-tender> (accessed 14 November 2022).

287 Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/knowledge-bank/renewable-energy-options-for-industrial-process-heat/> (accessed 21 October 2022).

288 COAG Energy Council (2019) Australia's national hydrogen strategy. <https://www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf> (accessed 24 October 2022).

289 Taylor A (2021) Australia and Germany partner on hydrogen initiatives. [Media release] <https://www.minister.industry.gov.au/ministers/taylor/media-releases/australia-and-germany-partner-hydrogen-initiatives> (accessed 24 October 2022).

290 Department for Business, Energy & Industrial Strategy (BEIS) (2022) Low carbon hydrogen business model: Government response. <https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1067504/low-carbon-hydrogen-business-model-government-response.pdf> (accessed 24 October 2022); BEIS (2021) Low carbon hydrogen business model: Consultation on a business model for low carbon hydrogen. <https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011469/Consultation_on_a_business_model_for_low_carbon_hydrogen.pdf> (accessed 24 October 2022).

291 IRENA (2019) Demand-side flexibility for power sector transformation: Analytical brief. <https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Dec/IRENA_Demand-side_flexibility_2019.pdf> (accessed 24 October 2022).

CATEGORY	CONSIDERATION
V2G, VPPs and consumer incentives	Successful integration of customer-owned storage into the grid depends not only on technical developments and consumer engagement, but also on the right market settings.[292] The ESB, in collaboration with energy market bodies and agencies, has commenced designing market reforms to support greater consumer choice and enabling consumers to reap greater value from their assets.[293] In light of projected EV uptake and the strong V2G scenario in AEMO's ISP, several actions are required to futureproof the grid and ensure a least-cost adoption of EV-related technologies. Example considerations include: • **Reviewing tariff structures** to enable efficient integration of V2G in the energy market and including consideration of time-of-use tariffs and dynamic pricing. This also includes consumer revenue streams for bidirectional charging.[294] • Ensuring consumer choice in EV-related products and services while **reducing complexity in regulations and standards.** This includes coordination to streamline and standardise infrastructure, software, hardware and communications between vehicles and the grid, particularly with respect to EV battery bidirectionality.[205] • The collection of **market information to resolve knowledge gaps** necessary for decision making. Uncertainties include consumer behaviour with respect to EV use and charging, the viability of different EV charging business models and the rate of adoption across the system. [295] This should be done through controlled pilot trials as well as real-world market data. In light of the role and benefits of aggregated DER, AEMO undertook demonstrations of VPP on the grid in 2021 to understand consumer experience and barriers to VPP integration.[296] However, minimal changes to regulation in the VPP market have occurred to date, due, in part, to technical readiness.[297] Example considerations for future uptake include: • Ensuring **revenue streams or compensation mechanisms** for both consumers and VPP providers are commensurate with the value provided to the grid. This includes ensuring the benefit to residential consumers participating in a VPP is similar or greater than that of a behind-the-meter battery and developing opportunities for commercial and industrial VPPs to provide demand-response services.[298] • Ongoing **review of regulatory hurdles** for providers in order to strike the right balance between reducing barriers to entry for new VPP providers and the provision of high-quality grid services.

292 RACE for 2030 (2021) N1 Opportunity Assessment: Electric vehicles and the grid – final report 2021. <https://apo.org.au/node/315087> (accessed 24 October 2022).

293 ESB (2022) Integration of consumer energy resources (CER) and flexible demand. <https://esb-post2025-market-design.aemc.gov.au/integration-of-distributed-energy-resources-der-and-flexible-demand> (accessed 24 October 2022).

294 RACE for 2030 (2021) N1 opportunity assessment: Electric vehicles and the grid – final report 2021. <https://apo.org.au/sites/default/files/resource-files/2021-10/apo-nid315087.pdf> (accessed 24 October 2022).

295 RACE for 2030 (2021) N1 opportunity assessment: Electric vehicles and the grid – final report 2021. <https://apo.org.au/sites/default/files/resource-files/2021-10/apo-nid315087.pdf> (accessed 24 October 2022).

296 ARENA (2019) Virtual power plant (VPP) demonstrations. <https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations> (accessed 24 October 2022).

297 AEMO (2022) Amendment of the market ancillary service specification (MASS) – very fast FCAS. <https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/amendment-of-the-mass/final-determination/final-determination.pdf?la=en> (accessed 24 October 2022).

298 Kuiper G (2022) What is the state of virtual power plants in Australia? Institute for Energy Economics and Financial Analysis. <https://ieefa.org/wp-content/uploads/2022/03/What-Is-the-State-of-Virtual-Power-Plants-in-Australia_March-2022_2.pdf> (accessed 24 October 2022); AEMO (2021) AEMO NEM virtual power plant demonstrations: Knowledge sharing report #4. <https://arena.gov.au/assets/2021/09/aemo-virtual-power-plant-demonstrations-report-4.pdf> (accessed 24 October 2022).

CATEGORY	CONSIDERATION
Coordinated long-term infrastructure planning and development	Focused and long-term coordinated planning between government and industry, with the support of the research sector, is required to make informed decisions that will deliver a low-cost energy system in the long run. This includes aligning industry and transport decarbonisation pathways with associated storage and infrastructure investments, as well as incorporating sector coupling in energy system planning. Example considerations include: • Coordinated planning between the heavy industry sector and government to **understand and align industry decarbonisation investment timelines and pathways with the rollout of key energy infrastructure**, including T&D, utility scale storage, hydrogen storage and distribution. This is critical for jurisdictions with energy systems dominated by heavy industrial loads, which can have a large impact on the grid. Coordination includes resolving critical knowledge gaps through pilots and analysis, and reaching consensus in decisions to catalyse energy transformation. This should also align with federal, state and territory strategies and policy. • Similarly, planning will be required around the **coordinated rollout of storage and infrastructure related to electrified and hydrogen road transport** (e.g. charging and refuelling stations, T&D augmentation and hydrogen supply chains). This is essential to ensure that the supply side and demand side are scaled up in parallel. • The **coupling of energy storage systems and the transport, electricity and industry sectors** can yield greater system flexibility, lowering overall energy system costs. This will require further analysis of the energy system to consider the opportunities and challenges related to sector coupling (e.g. extending energy system modelling to include the impacts of bidirectional charging, hydrogen electrolysers and pipelines, the storage and use of waste heat and other sector coupling developments). Such analysis may help coordinate planning and identify near-term sector coupling opportunities in new and existing residential and industrial precincts and emerging hydrogen hubs.

4.2 Technology recommendations

Australia will need to rapidly develop a pipeline of projects across a portfolio of energy storage technologies to address key technology challenges across different end-use applications and geographical locations.

Supporting Australia's diverse end-use and regional energy needs will require storage technology commercialisation and scale up. These activities need to take advantage of both existing commercial technologies and those that are currently in development and reaching commercial milestones. This report has identified six key technology challenges and associated recommendations to support the decarbonisation of Australia's grids and industrial electrical applications, and to create commercially viable decarbonisation options for Australian industries reliant on industrial process heat.

Although this report has examined energy storage needs to 2050, the technology recommendations require urgent action and attention prior to 2030. For example, to achieve net zero commitments, industry and government will require access to a sufficient level of commercially competitive, widely deployed and easy-to-finance (CRI 5–6) technology options. Scaling up technologies in development can take up to a decade, with some technologies requiring long lead times for approvals and construction. As such, leaving technology development to post-2030 in many cases will be too late. Further, although Australia can seek solutions from overseas, there are Australian businesses that have innovative technologies that could be exported and become world-leading.

The recommendations are summarised in Table 14 and are discussed further in this section. It is important to note that identifying and accelerating cost reductions, particularly at larger scales, applies across all categories and requires greater levels of engagement, international collaboration and cross-cutting RD&D.

Table 14: Summary of technology recommendations

CATEGORY	CHALLENGES	RECOMMENDATIONS
Short-duration electricity storage (1–4 hours)	Short-duration storage is expected to play a major role in decarbonisation across Australia's grids and its industries, particularly in the near term (to 2030). Although commercially mature options exist to meet Australia's short-duration storage needs, there are supply chain risks that could create deployment bottlenecks and drive up prices.	• Continue to deploy commercial utility scale (100+ MWh) short duration electrical storage technologies alongside demonstration of technologies currently in development to create optionality. • Consider and develop strategies to de-risk battery supply chains through a number of strategic diversification pathways, including, but not limited to: developing domestic value chains; developing resource circularity; and investing in research, development and demonstration (RD&D) for alternative battery chemistries.
Medium (4–12 hours) and long intraday (12–24 hours) electricity storage	Australia's medium-to-long intraday storage demand will become more significant in the near term with deeper levels of renewables penetration, and for industry sites with limited grid connectivity. Although some commercial technologies exist, they are not always applicable depending on the end use or region in question. There are also several other technology options currently in development, but these are not yet commercially competitive and require further demonstration and deployment.	• Rapidly demonstrate and commercially deploy medium-to-long intraday-duration technologies capable of providing 100+ MWh to multi-gigawatt hours of storage to create a diverse set of options for major grids and industry applications. • Conduct further regional studies to better understand geological storage opportunities, such as with A-CAES and PHES subsystems, as well as opportunities to take advantage of existing capital and sites, including evaluating opportunities created through mine closure efforts.
Long multiday (24–48 hours) and seasonal (100+ hours) electricity storage	Multiday and seasonal storage will play a key energy 'insurance' and resilience role in major and isolated grids, with deployments expected to increase beyond 2030 as higher levels of renewables are adopted. However, at these durations, storage technology options are limited and often have long lead times, with many stakeholders still considering investment options, including those that minimise storage investments, and evaluating trade-offs as they transition to net zero.	• Conduct further analysis to better understand Australia's requirements for multiday and seasonal storage, the trade-offs that exist and the technology pathways available. • Develop the pipeline of projects to meet Australia's potential long-term seasonal and multi-day needs, including identifying and implementing opportunities to accelerate PHES deployments, and progressing emerging multi-day and seasonal technologies.
Storage for mid-temperature processes (150–500°C)	Australia has many industries and industrial sites, small and large, that are currently reliant on what is classified as mid-temperature industrial process heat. These processes are not always easy to decarbonise with conventional electrical pathways alone, creating a potential opportunity for the use of thermal storage or the storage and use of hydrogen. There is a broad range of solutions that are mature, or nearing technical maturity. However, a lack of information on technology options and the CAPEX involved in retrofitting existing plants are barriers to implementation.	• Pilot and commercially deploy end-to-end thermal and hydrogen storage systems, alongside investigating electrification options, in a range of industrial processes to better understand cost, business model and deployment considerations, and reduce actual and perceived risks.

CATEGORY	CHALLENGES	RECOMMENDATIONS
Storage for high-temperature processes (500°C and above)	High-temperature industrial processes are difficult to decarbonise. Although this report focuses on alumina, Australia has various industries with similar high-temperature requirements spanning cement, chemicals, mineral processing and steel. For these industries, several decarbonisation pathways exist: electrification, the use of thermal energy systems or the use of hydrogen to create the heat required. Regardless of decarbonisation pathway, significant knowledge gaps remain related to storage costs and how storage may impact overall plant costs and operations. The decarbonisation pathway may also have broader infrastructure implications given the scale of these industries.	• Pilot and analyse integrated generation and storage technologies for different industrial processes to help identify low-cost pathways and their storage implications (to operations and local energy infrastructure).
Storage and distribution of hydrogen and hydrogen carriers	The storage and distribution of hydrogen and hydrogen carriers will be important in ensuring sufficient volumes are available at refuelling stations, for industrial applications and to support export operations. However, this will depend on export demand, domestic hydrogen industry development and how value chains are optimised. Given the time line related to Australia's ambition for hydrogen export and the domestic use of hydrogen to support decarbonisation, further analysis, piloting and demonstration will be required to help minimise technical and commercial risks related to storage and buffering.	• Analyse optimal distribution models and associated storage volumes required such that sufficient hydrogen (or hydrogen carriers) is stored to support export demand and is available for domestic applications and processes. • Pilot, demonstrate and scale up bulk and small-volume storage systems for hydrogen and its derivatives, and their integration into hydrogen distribution networks, to help de-risk projects across different end-use applications.

Short-duration electricity storage

Continue to deploy commercial short-duration electricity storage technologies alongside demonstration of technologies currently in development to create optionality.

Short-duration storage is expected to play a major role in decarbonisation across Australia's grids and its industries, particularly before 2030. Under the *Step Change* scenario, for the NEM, total short-duration storage could account for approximately 55% of electricity storage power capacity by 2030 and 65% of power capacity by 2050. In WA, total short-duration storage could account for 60% of power capacity by 2030 and 50% by 2050. Short-duration storage will be equally important for fringe-of-grid and remote Australian industries such as mining, manufacturing and agriculture.

- **Continue to deploy and bring down costs related to commercial utility scale short-duration technologies** to help create options that support different operational end-user needs. This could include different requirements related to footprint, power, cycling, response times and operating temperatures. Greater project activity will increase learnings and related domestic skills, resulting in efficiencies and economies of scale. Supporting ecosystem actions are discussed further in Section 4.3.
- **Invest in RD&D for alternative battery technologies** specific to the Australian context and aligned with domestic capabilities.[299] For example, VRFB are deployed at commercial scales overseas, and ZNBR batteries have been demonstrated at pilot scales. However, flow batteries have not been deployed at scale in Australia, and supply chains have not yet reached commercial scale domestically. Technologies with earth-abundant materials in RD&D stages of development could also be considered, such as Na-ion batteries or lithium-based battery chemistries with reduced critical mineral content. Demonstrations could include Australian technology developers, as well as partnering with overseas OEMs.

299 Bruce S et al. (2021) Critical energy minerals roadmap. CSIRO, Australia.

Consider and develop strategies to de-risk battery value chains through a number of strategic diversification pathways.

Li-ion batteries are commercially mature and broadly expected to play a major role in meeting short-duration storage needs. However, there are short-term price risks and long-term supply chain risks that need to be considered. Global demand for batteries is expected to increase, primarily to meet the storage demand from the EV market. This is placing pressure on supply chains with respect to critical mineral production through to battery cell manufacturing. Furthermore, battery materials processing is concentrated in a few countries, and battery cell manufacturing is dominated by a few advanced manufacturers overseas.

De-risking the lithium battery value chain will be a national consideration and could be achieved through one or more of the following actions:

- **Implement measures and partnerships to secure supply** of Li-ion batteries from equipment manufacturers to meet Australia's immediate short-duration needs and near-term targets. This could include ways to increase the involvement of overseas original equipment manufacturers (OEMs) with Australian raw mineral supply chains.
- **Develop technologies and models for developing resource circularity (e.g. second-life use and recycling of lithium-batteries)** in order to overcome supply constraints and price volatility of lithium batteries and critical battery metals.[300]
- **Develop a domestic value chain** from high-purity minerals and metals through to battery manufacturing.[301] This could include the development of battery hubs in proximity to strategic battery minerals resources, and processing and manufacturing capabilities.[302]
- **Partnering with overseas battery technology OEMs to set up domestic manufacturing** in Australia to meet domestic demand.[303] This may also include considering whether Australia's battery imports stem from a diversified set of manufacturers with a diversified set of materials and component suppliers.
- **Conduct a deeper study on supply chains** to estimate the timing and magnitude of projected supply chain constraints, and to inform Australia's Li-ion battery risk management strategy.

Medium to long (intraday) electricity storage

Australia's medium to long (intraday) storage demand will play a key role in the near term with deeper levels of renewable penetration. For example, the need for medium storage is particularly significant in WA, with medium-duration storage accounting for approximately 40% of storage power capacity (GW) by 2030.

There are various technologies that could help meet this need. This project identified PHES, Li-ion batteries, VRFB and CST plus storage as near-term solutions that could be deployed and demonstrated. The analysis also highlighted systems currently at pilot scales of development that are being actively considered, including A-CAES, eTESe and gravity storage. However, these systems are not always applicable depending on the end use or region in question, and many have yet to be demonstrated at scale, particularly at longer durations.

Accelerate the demonstration, commercial deployment and scale up of medium- to long (intraday)-duration technologies to create a diverse set of options for both near-term and future needs.

- **Continue to deploy commercial scale projects and support value chain development and RD&D activities** to target technology constraints and cost reductions. Technologies deployed at commercial scale in Australia include such as PHES, Li-ion batteries and VRFB. For example, high import costs for flow battery systems and components can be addressed by establishing a domestic OEM presence and developing part of the value chain (e.g. electrolyte and component manufacturing) in Australia. In many cases these projects can take advantage of international experience and existing or planned projects.

300 Zhao Y et al. (2021) Australian landscape for lithium-ion battery recycling and reuse in 2020, CSIRO. https://fbicrc.com.au/wp-content/uploads/2021/03/CSIRO-Report-Australian-landscape-for-lithium-ion-battery-recycling-and-reuse-in-2020.pdf (accessed 24 November 2022)

301 Bruce et al. (2021) Critical energy minerals roadmap. CSIRO, Australia; Future Battery Industries CRC (2022) Towards 2030: Australia's battery powered future. <https://fbicrc.com.au/wp-content/uploads/2022/03/Towards-2030-Australias-battery-powered-future-FINAL.pdf> (accessed 24 October 2022).

302 Future Battery Industries CRC (2021) Accelerating Battery Industry Hub Development in Australia < https://fbicrc.com.au/wp-content/uploads/2021/10/Accelerating-Hub-Development-of-Australia.pdf> (accessed 24 November 2022)

- **Demonstrate and deploy technologies that have not yet been deployed at commercial-scale in Australia to provide more options** to meet regional- and industry-specific needs that may be required closer to 2030 and beyond. This includes large-scale projects that demonstrate different technologies in different environments in order to increase certainty around system costs and to identify and overcome technical barriers to scale up. Medium- to long- (intraday) duration technologies include CST plus storage, A-CAES, eTESe, gravity storage and hydrogen storage (e.g. compressed hydrogen, underground hydrogen and metal hydrides). These projects can also be used to demonstrate alternative configurations of systems and identify opportunities for cost reductions. For example, CST plus storage could be configured in multiple ways, and the power capital costs and footprint related to eTESe could be significantly reduced via the use of supercritical CO_2 turbines.

Conduct further geographical and geological studies to accelerate the deployment of A-CAES and PHES subsystems, including evaluating opportunities created through mine closure efforts.

- **Identify suitable geological sites for deploying commercial A-CAES systems** across Australia. It would be beneficial to identify hard rock sites to be in proximity to power networks and industrial users. To extend siting opportunities beyond hard rock, geological studies should be undertaken with respect to other geologies, such as porous rock (aquifers, depleted oil and gas wells).[304] This analysis should consider opportunities to reduce costs by taking advantage of existing infrastructure and analyse environmental and social impacts.
- **Conduct RD&D and siting studies on new pumped hydro subsystems** (e.g. small PHES systems for low head height and saltwater PHES systems).[305] This can help tackle uniquely Australian challenges such as constraints with respect to low elevation and water availability.
- **Evaluate sites and storage opportunities that are or may become available through mine closure efforts.** Mine closure is a multibillion dollar challenge for the Australian and global mining industry. It has been estimated that Australia has over 65,000 abandoned or former mine sites,[306] and that over 150 mines are projected to close between 2019 and 2030.[307] One energy storage example can be seen through the Kidston Pumped Hydro Storage Project in Queensland, which takes advantage of two existing mining pits.[308] Importantly, these sites are often large scale, have established infrastructure and may have existing capital that could be leveraged, turning what is a challenge for Australia's mining industry into an opportunity.

Multiday to seasonal storage

Conduct further analysis to better understand Australia's requirements for multiday and seasonal storage and the trade-offs that exist.

From 2030 onwards, multiday and seasonal electricity storage is expected to play a key role in the NEM alongside infrastructure development as Australia's energy system transitions towards net zero. Under the *Step Change* scenario, the provision of power over long durations accounted for a large share of energy capacity (GWh) in the NEM, with multiday and seasonal storage meeting around 80% and 60% of storage in 2030 and 2050 respectively. This requirement was found to be equally valuable for remote communities and large industries in isolated grids as higher levels of renewables are achieved.

However, at these durations, storage technology options are limited and often have long lead times. As a result, many stakeholders consulted are still considering investment options to meet this need, including those that minimise storage investments, and evaluating trade-offs as they transition to net zero (e.g. investing in T&D, energy efficiency and/or technologies that reduce or defer required load, as well considering the continued use of small levels of fossil fuels as backup).

303 Bruce et al. (2021) Critical energy minerals roadmap. CSIRO, Australia.

304 Bowen et al. (2021) USAID grid-scale energy storage technologies primer. National Renewable Energy Laboratory. <https://www.nrel.gov/docs/fy21osti/76097.pdf> (accessed 20 October 2022).

305 U.S. Department of Energy (2022) HydroWIRES initiative research roadmap. <https://www.energy.gov/sites/default/files/2022-02/HydroWIRES%20Roadmap%20FINAL%20%28508%20Compliant%29_0.pdf> (accessed 24 October 2022); Misech A, Schleiss A, Fry J, Multhaupt H (2021) Hydropower Europe: Research and innovation agenda. Association of European Renewable Energy Research Centres. <https://hydropower-europe.eu/publications/strategic-industry-roadmap-and-research--innovation-agenda/> (accessed 24 October 2022).

306 Saggar S, Rey R, Lin C (Editors) (2022) WA 2050: People, place, prosperity. <https://www.uwa.edu.au/institutes/public-policy/-/media/Public-Policy/Documents/WA-2050---People-Place-Prosperity_WEB.pdf> (accessed 24 October 2022).

307 Vivoda V, Kemp D, Owen J (2019). Regulating the social aspects of mine closure in three Australian states. Journal of Energy & Natural Resources Law 37, 405–424.

308 Genex (n.d.) 250MW Kidston pumped storage hydro project. <https://genexpower.com.au/250mw-kidston-pumped-storage-hydro-project/> (accessed 24 October 2022).

Given this complexity, further analysis should be conducted to better understand the value of multiday and seasonal storage to Australia across different end-use applications, particularly in the near term. This analysis should aim to:

- **Determine the value of multiday and seasonal storage.** This could include identifying storage implications, risks and trade-offs related to different policy and industry decision pathways. Decision pathways include generation development decisions, the degree of technological and geographical diversity in the future power system, resilience to VRE variability and T&D investments.
- **Understand the duration of storage required.** For example, there is a need to consider the insurance value of seasonal storage for month-long windows given extreme weather and uncertainties relating to climate change. This could be supported via further climate and extreme weather sensitivity analysis.
- **Consider the social implications of multiday and seasonal storage.** When considering remote communities, it is important to understand the direct and indirect services that an existing solution may be providing and the flow-on effects with storage deployment. For example, in some communities, the services that bring in diesel are also used to bring in other items, including food, which can help drive down the costs of these items for the community.
- **Analyse the project pipeline and timeline to meet Australia's multiday and seasonal storage requirements.** Multi-day and seasonal storage projects, particular for major and isolated grids often have a long planning, approval and construction lead-times. As such, there is value in better understanding the time at which storage may be required across different scenarios and sensitivities and planning backwards to understand the decision making timeline, considering the current project pipeline.

Develop the pipeline of projects to meet Australia's potential long-term seasonal and multi-day needs, including identifying and implementing opportunities to accelerate PHES deployments, and progressing emerging multi-day and seasonal technologies.

In terms of storage technology options, this project focused on technologies that are at a higher commercial readiness level and those that could operate at scale. In many cases, this resulted in a focus on PHES and hydrogen in various forms to meet multiday and seasonal storage needs.

However, PHES and hydrogen both face several constraints and limitations. For example, although there is a large number of potential pumped hydro sites, these sites are not available in all regions and can have long project lead times. Similarly, although hydrogen has flexibility, the hydrogen value chain will require scale in order to be cost-competitive, and will need to be supported with appropriate storage infrastructure.

Further technology evaluation is required, particularly given the complexity and site specific nature of multiday and seasonal storage for major grids and large-scale and isolated grids.

- **Build on existing Australian PHES analysis to speed up project development timelines, and minimise project, environmental and social impacts.** This could include further site screenings and assessments, reviews of regulatory and approval processes, early community engagement and environmental assessments. This should also consider storage potential (e.g. power and energy capacity) in line with Australia's potential long-term seasonal and multi-day needs, and proximity to current and planned infrastructure (e.g. distance to network).
- **Extend the analysis of multi-day and seasonal hydrogen storage systems to determine the costs and value of shared hydrogen infrastructure to support Australia's power, industry and hydrogen export requirements.**
  - While hydrogen can provide a flexible long duration and seasonal storage option for end-use applications, the competitiveness of end-use industries using hydrogen will depend on costs related to establishing a hydrogen production and distribution network. For example, although hydrogen peaker plants could provide an option for replacing natural gas peakers on a given site, significant scale, as well as suitable storage and pipeline infrastructure. As such further analysis is required to better understand the costs of developing hydrogen-related production and distribution infrastructure, including shared hydrogen infrastructure.
  - Conversely, the scale of these projects may provide opportunities for other industries and communities to leverage the investment. Examples include hydrogen pipeline infrastructure or investment in large-scale electricity storage in close proximity to an isolated grid or end-use industry. This may also result in other valuable assets being developed, such as those related to water, ports and power generation.

Depending on the type of infrastructure and its value to major or isolated grids and industry, shared assets may be particularly important in de-risking investments as Australia's energy export market develops. As such the value of joint government and industry investment to create shared storage assets should be evaluated, taking into consideration existing plans related to hydrogen hubs and Australia's National Hydrogen Strategy.[309]

- **Conduct further analysis on technologies in R&D stages that have not been assessed in this report.** There is a broad range of technologies that are being researched that were beyond the scope of this report and could provide multiday and seasonal storage. These include alternative chemical storage technologies (including various hydrogen derivatives) that have been mentioned throughout the report. In many cases these technologies will require further development and attention to progress them from lab and pilot stages to being demonstrated at larger scales.

Storage for mid-temperature processes

Pilot and commercially deploy end-to-end thermal and chemical storage systems in a range of manufacturing processes to better understand cost, deployment and market considerations.

Australia has many industries and industrial sites, small and large, that are currently reliant on what is classified as mid-temperature industrial process heat (range 150–500°C). At thermal processes above 150°C, decarbonise with conventional electrical pathways (e.g. heat pumps) is not always straightforward and requires site evaluation. This creates an opportunity to take advantage of thermal storage or the storage of a chemical (e.g. hydrogen), which can be used to produce the required heat. In both cases, there is a broad range of thermal and chemical systems that are mature, or nearing technical maturity, and could be developed, piloted and commercially demonstrated to support a range of manufacturing plants.

However, decisions related to the decarbonisation of mid-temperature industrial processes can be quite difficult for many small to medium sized manufactures who may not have capacity and access to expertise to evaluate the vast range of decarbonisation pathways. For example, for electrification, several mature technologies exist to decarbonise processes above 150°C (for example MVR, electric boilers, infrared heaters), however their deployment depends on the relative cost of electrification versus other options. Thermal storage media such as molten salts are commercially deployed in the power sector and CST systems are seeing significant uptake globally for industries using mid-temperature steam. However, there are currently limited commercially available end-to-end thermal systems for different industrial process heat applications. For hydrogen, although tank-based hydrogen storage systems are mature, they are not commonly used across sites to meet process heat requirements, and sites may need to consider the use of hydrogen with existing boilers or burners.

Pilots and commercial deployments will be key to addressing information gaps and may eventually lead to the development of tools to help simplify the technology evaluation process (see cross-cutting R&D in Section 4.3).

- **Increase technical and cost data availability and knowledge of deployment considerations through pilots and commercial demonstrations** of electrification, thermal and chemical storage options. This can help to:
  - Increase knowledge of total system and replacement costs. For example, understanding the cost of replacing existing assets (e.g. gas-fired boilers) with new thermal storage systems. This includes both capital costs and ongoing operation and maintenance costs.
  - Evaluate comparable costs between storage technology options for a given process and output. For example, the cost of producing a tonne of high-pressure steam or hot water within a given system versus the cost of producing the same output through the burning of a fossil fuel.
  - Assess business model opportunities. With various manufacturing precincts and hydrogen hubs under development, there could be opportunities to consider different types of business models. For example, considering combined gas, heat and power opportunities, service-based pricing, shared infrastructure and opportunities to leverage waste streams (e.g. waste heat).
  - In addition to helping improve commercial readiness, these projects can also increase stakeholder awareness (particularly related to thermal technologies; see Section 4.3), help understand standards and certification requirements and identify the skills and training required to manage and maintain these systems.

309 Taylor A (2021) Future hydrogen industry to create jobs, lower emissions and boost regional Australia. [Media release] <https://www.minister.industry.gov.au/ministers/taylor/media-releases/future-hydrogen-industry-create-jobs-lower-emissions-and-boost-regional-australia> (accessed 22 October 2022).

Storage for high-temperature processes

Although this report focused on alumina, Australia has various industries with high-temperature industrial process requirements that are difficult to decarbonise, including cement, chemicals, mineral processing and steel. For these industries, several decarbonisation pathways exist (e.g. electrification, the use of thermal energy systems or the use of hydrogen to create the heat required), all requiring some form of storage to support what are mostly continuous operations.

There are several unknowns relating to energy inputs, energy storage and end-use processes that pose a barrier to decision making around pathways. In the context of industrial plants, combined integrated system costs (including energy inputs, storage and end-use processes) must be considered and optimised in order to pick a pathway. For example:

- Energy input availability and costs: The cost of electricity for an electrification pathway will depend on grid-side developments. Conversely, the cost of hydrogen and the associated scale of hydrogen infrastructure, to facilitate a hydrogen pathway, are also uncertain.
- Energy storage technologies: Although many storage technologies are mature at low and mid-temperature ranges, technical challenges remain with regard to high temperature ranges (e.g. materials); consequently, cost data to support decision making are lacking.
- End-use processes: A final uncertainty relates to the end-use processes themselves and the process change that may be required by using different technologies. For example, the use of hydrogen in the alumina refining process could introduce water to the process, which would have to be carefully managed.

This creates a high-risk environment for investment decision making, particularly given high RD&D and CAPEX costs for the industrial sector. This risk is heightened when considering the retrofitting of existing plants, where firms have incurred the costs of the plant. Integrating a new storage system often requires changing other parts of the plant, which could run into technical challenges and result in cost blowouts. The risk for greenfield plants is lower because integrated systems are designed from the start, but the risk remains considerable.

Pilot projects and further studies of integrated generation and storage technologies for different industrial processes can help identify low-cost pathways and their implications.

There are several projects and initiatives underway that will help provide knowledge in these industries, including the Australian Industry Energy Transition Initiative,[310] the HILT CRC[311] and several ARENA-funded initiatives across electrification, thermal technologies and hydrogen utilisation in heavy industry.[312]

- **Accelerate pilots and trials of integrated generation, storage and industry processes** to help identify the lowest-cost pathways and generate knowledge that could be leveraged across industries. While some pilots exist (e.g. in Alumina) it is suggested that this effort is accelerated given the scale of industries with high-temperature industrial process heat requirements and the timeline for change and decarbonisation. These pilots can help uncover a significant amount of technical and commercial information that needs to be learned from trialling various new technologies within industrial processes. These trials should also consider onsite and regional storage implications, such as storage that may be needed for the grid or whether a hydrogen pipeline may be required.

Storage and distribution of hydrogen and hydrogen carriers

The *Hydrogen Superpower* scenario and individual sector analysis highlights the scale and potential role of hydrogen (and hydrogen carrier) storage in supporting Australia's hydrogen export ambitions, as well as the use of hydrogen across industry and transport applications.

There are various storage technology options, with different levels of technical maturity and risk, that could be leveraged based on how the hydrogen industry develops and how individual value chains are optimised. Australia's has an ambitious timeline for the development of a large scale hydrogen export industry, underpinned by domestic use, both nationally and across jurisdictions,[313] however faces many uncertainties and challenges including technical and commercial risks related to storage and buffering.

310 Australian Industry Energy Transition Initiative (n.d.) Home. <https://energytransitionsinitiative.org/> (accessed 24 October 2022).

311 HILT CRC (n.d.) Home. <https://www.hiltcrc.com.au/> (accessed 24 October 2022).

312 ARENA (2016) Integrating concentrating solar thermal energy. <https://arena.gov.au/projects/integrating-concentrating-solar-thermal-energy-into-the-bayer-alumina-process/> (accessed 24 October 2022); ARENA (2021) Renewable hydrogen could reduce emissions in alumina refining. <https://arena.gov.au/news/renewable-hydrogen-could-reduce-emissions-in-alumina-refining/> (accessed 24 October 2022); ARENA (2022) Word-first pilot to electrify calcination in alumina refining. <https://arena.gov.au/news/world-first-pilot-to-electrify-calcination-in-alumina-refining/> (accessed 24 October 2022).

313 COAG Energy Council (2019) Australia's national hydrogen strategy. <https://www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf> (accessed 22 October 2022).

Analyse the optimal distribution models and associated storage volumes required such that sufficient hydrogen (or hydrogen carriers) is stored and available for export and domestic applications and processes.

This report provides analysis to highlight the scale of hydrogen storage that may be required to support hydrogen energy exports and domestic industry applications. It included national hydrogen storage estimates by building on the *Hydrogen Superpower* scenario, analysis of the volume of hydrogen that may be required to support alumina refining under a hydrogen pathway, an estimate of stored hydrogen that may be required to support liquefied hydrogen export and a qualitative discussion of stationary hydrogen storage to support heavy-duty hydrogen vehicle refuelling networks. While valuable in helping to communicate the challenge, further analysis is required to:

- **Understand different volumes of hydrogen and hydrogen carrier storage** that may be required at different points along the hydrogen value chain to support Australian exports and domestic decarbonisation objectives.
- **Understand how value chains could be optimised,** and how investments in hydrogen infrastructure and hydrogen hubs can help deliver lower-cost outcomes in the long run.
- **Identify additional deployment considerations** (e.g. geographical requirements, cost reduction opportunities and safety and other handling requirements) for hydrogen storage and end uses beyond those discussed in this report.

Pilot, demonstrate and scale up of bulk and small-volume storage technologies for hydrogen and its derivatives, and their integration into hydrogen distribution networks, to help de-risk projects across different end-use applications.

The development of a domestic hydrogen economy and hydrogen energy exports will depend on the demonstration and scale up of hydrogen production, storage and distribution, and end use in parallel. How hydrogen supply chains will be optimised and decision making on hydrogen infrastructure investments will depend, in part, on the costs of integrated hydrogen storage and distribution models. This relies on demonstration and scale up of storage and distribution technologies to ascertain costs and technical readiness, and to deliver cost reductions. For example:

- **Conduct studies to identify suitable sites to pilot and demonstrate underground hydrogen storage**, including depleted gas fields, aquifers and engineered caverns across Australian jurisdictions. This analysis can build on existing work[314] and can help to expand Australia's options for underground storage given the limited number of salt caverns in Australia and their distance from prospective hydrogen production and use.
- **Continue commercial demonstration and scale up of dedicated hydrogen pipelines and blended gas networks** across Australian jurisdictions. Deliver improvements on pipeline materials to provide cost-effective and safe hydrogen storage and distribution, and conduct further RD&D to develop requirements for line packing of hydrogen and hydrogen blends to meet projected export and domestic demand.
- **Deliver improvements to compression and liquefaction** processes and the storage of compression and liquefied hydrogen to improve on storage costs and resolve challenges such as boil-off. Examples include reducing the energy required to liquefy hydrogen, improving the insulation of tanks (using new designs and materials) and improving heat exchangers and coolants.[315]
- **Pilot and demonstrate integrated hydrogen distribution models** that incorporate different forms of hydrogen storage to support decision making around least-cost value chains for export, industrial use and transport. This could include one or more of the storage technologies discussed above, as well as the storage and the use or conversion of hydrogen derivatives. These should be analysed and optimised in the context of production costs, the costs of distribution (including distance), the costs of intermediary processes (e.g. compression, liquefaction, ammonia production, hydrogen extraction and purification) and end uses in industry and transport, as well as overseas demand. This should also include the development of hydrogen safety standards across all transmission and handling points.

314 Ennis-King J et al (2021) Underground storage of hydrogen: mapping out the options for Australia. <https://www.futurefuelscrc.com/wp-content/uploads/FutureFuelsCRC_UndergroundHydrogenStorage2021.pdf> (accessed 24 October 2022).

315 Srinivasan V, Temminghoff M, Charnock S, Hartley P (2019) Hydrogen research, development and demonstration: Priorities and opportunities for australia. CSIRO, Australia.

4.3 Ecosystem recommendations

Greater levels of domestic and international engagement can help Australia establish domestic supply chains and de-risk and reduce the cost of renewable energy storage deployment.

To support energy market and technology recommendations, strong collaboration and engagement between stakeholders across the energy ecosystem is required. Further, this will be important to ensure that storage demand is supported by effective domestic supply chains. This includes the skills and services needed to support cost effective manufacture, deployment, integration and ongoing operation of storage assets, and ensuring that technologies and knowledge are continually enhanced to improve outcomes and de-risk projects. Specifically, this will require:

- **Stakeholder engagement:** Collaboration between government, industry (including investors), research institutions and community will play an important role in choosing technology pathways and designing the future energy market.
- **International collaboration:** There is room for Australia to further participate in international energy storage dialogues and RD&D activities to support the development and deployment of energy storage systems in Australia, and to avoid duplication of effort and investment.
- **Cross-cutting RD&D:** Further consideration of safety and testing, land use and environmental impact, skills and cross-cutting research will play a valuable role in supporting the adoption and scale up of storage technologies in Australia.

Stakeholder engagement

Collaboration between government, industry (including investors), research institutions and community will play an important role in choosing technology pathways, designing the future energy market and ensuring that appropriate expertise is available to help Australia scale up, reduce costs and increase reliability across storage technologies.

Government

In order to deliver effective policy and market design, government will need to engage extensively with industry and research institutions and facilitate cross-sector consensus building. Elements that will require collaboration to drive policy include:

- Deepening understanding of end-user diversity and complex needs and requirements. This includes consulting energy generators, storage providers and industry end users.
- Identifying interdependencies across parts of the energy system, and collaborating with industry on coordinating the timing of public infrastructure rollout, as well as the timing of industry decarbonisation pathway decisions.[316] This includes coordinating sector coupling in light of its role in demand-side flexibility and lowering overall system costs, as well as understanding the impacts of proposed policy decisions and deployment pathways through consultations with industry and the research sector.
- Engaging with First Nations representatives in decision making around energy storage policy, legal and regulatory frameworks to remove barriers to access to storage technologies, ensuring comprehensive consideration of land and water rights, enhancing economic and job opportunities and supporting partnership opportunities with industry. Avenues include the First Nations Clean Energy Network[317] and the co-design of a First Nations Clean Energy Strategy, which is prioritised under the National Energy Transformation Partnership.[318]

316 World Energy Council (2020) Five steps to energy storage: Innovation insights brief 2020. <https://www.worldenergy.org/assets/downloads/Five_steps_to_energy_storage_v301.pdf> (accessed 24 October 2022).

317 First Nations Clean Energy Network (2022) Introducing the First Nations Clean Energy Network. <https://www.firstnationscleanenergy.org.au/> (accessed 24 November 2022).

318 Department of Climate Change, Energy, the Environment and Water (2022) National energy transformation partnership. <https://www.energy.gov.au/government-priorities/energy-ministers/priorities/national-energy-transformation-partnership> (accessed 24 November 2022).

- Assessing and working with industry and research to establish onshore testing facilities, laboratories and centres of excellence to ensure that Australian storage technology proponents have timely and cost-effective access to the facilities required to demonstrate their products and meet the criteria to access Australian and export markets. This is also important to ensure overseas products align with Australian requirements.
- Partnering with industry to support the establishment of integrated domestic value chains, from the production of raw and processed materials through to componentry manufacturing and system assembly of energy storage technologies.
- Partnering with industry and research to support the establishment of end-of-life management systems and technologies to reduce supply chain risks related to critical minerals. Examples include the recovery of high-value metals found in batteries, and vanadium electrolyte solution recycling.
- Encouraging knowledge sharing through processes or platforms, and tying this to project funding support.

Industry

Industry will need to collaborate with government in order to contribute to effective policy outcomes, as well as with other industry and technology proponents and the research sector to develop storage systems to meet their energy and decarbonisation needs. Examples include:

- Helping enhance the policy and research sectors' understanding of industry complexities and needs with respect to energy storage decisions, including through knowledge-sharing platforms established by government. This can be conducted by individual industry organisations or through the formation of industry consortia that face similar needs.
- Enhancing channels linking energy storage technology providers and industry end users to improve the matching of storage solutions to end users in the marketplace. Industry end users include large industrial players as well as small- to medium-sized enterprises and First Nations businesses.
- Engaging technology proponents and collaborating with industry clusters and research institutions to solve technical challenges with respect to integrating energy storage technologies into industry operations.
- Communicate energy storage opportunities to the investment community, including the role of storage technologies in different end use markets, to support project and technology development and the growth of Australian technology solutions.
- Developing Australia's future workforce in partnership with the education sector to grow the skills required for a decarbonised energy system. Alternatively, working with government to attract the required skills and capabilities via Australia's skilled migration strategy. This will include helping identify and develop domestic skills and capabilities to build, maintain and service energy storage systems, including improved accessibility to those skills and capabilities in remote areas.
- Working with international OEMs or domestic technology proponents to ensure there is a suitable distribution and integration presence (or partner) in Australia to guarantee accessible and cost-effective ongoing support, servicing and maintenance of deployed systems.

Research institutions

In order to translate energy storage R&D into tangible outcomes across the energy system, the research sector will need to engage with industry and government on the following:

- Identifying and prioritising high-impact energy storage research areas that are key priorities for Australian industry and that solve uniquely Australian challenges, partnering with industry and government to achieve commercial implementation.
- Avoiding duplication of effort across Australia's research institutions and industry endeavours.
- Communicating and building industry awareness about emerging and mature technology options available and their applicability to industry requirements. This includes improving the awareness of small- to medium-sized enterprise and First Nations businesses of energy storage opportunities.
- Providing decision-making support capabilities and tools, such as modelling and optimisation, for policy makers and industry.

Society and communities

Government, industry and the research sector will need to effectively communicate with the public and engage communities in decision making to bring about socially desired outcomes with respect to energy storage. This includes:

- Public awareness
  - Increasing awareness and understanding of the importance of energy storage for decarbonising the energy system and maintaining energy security and reliability, as well as increasing awareness and understanding of energy storage technologies beyond batteries and PHES[319]
  - Communication and transparency with consumers around the implications of grid or third-party-controlled storage assets, including the benefits and how information will be communicated between providers and consumers[320]
  - Effective management of biases in the media and communications that can result in public misinformation, and provide consistent fact-based messaging
- Community engagement
  - Effective engagement of communities around their energy needs and requirements, and equitable deployment of energy storage to deliver improved access to reliable and secure energy
  - Early engagement of communities in decision-making processes, particularly in instances where communities benefit or are adversely affected by energy storage deployments; this includes engagement for energy storage projects taking place on First Nations' land or areas with significant cultural and spiritual meaning
  - Development of citizen participation instruments related to Australia's energy storage policy to ensure consideration of the public in policy design, including First Nations communities
- Skills and employment
  - Effective engagement of the workforce employed in high-emitting industries (e.g. the fossil fuel sector) to solve structural issues arising from the energy transition, and exploration of new opportunities for reskilling and training arising from energy storage deployments
  - Establishing partnerships that can deliver revenue and employment opportunities to First Nations businesses and communities arising from energy storage projects.

International collaboration

With growing global recognition about the importance of energy storage, collaboration can accelerate progress by coordinating RD&D efforts, growing domestic capability and enhancing relationships with key trading partners.

Across the world there is growing political and business recognition of the importance of energy storage to meet decarbonisation objectives. Several international public strategy documents have been published and funding programs established on the topic of energy storage, recognising the need to address the current technical, cost and market challenges to effective deployment.

International collaboration can help identify common challenges and mutual priorities with respect to energy storage, and improve investment efficiency by avoiding duplication of effort. Knowledge sharing and overseas engagements can help enhance domestic RD&D capability by accessing state-of-the-art developments and best practices in technology, business and policy. Raising Australia's international profile and collaborating on cross-cutting areas such as standards, certification and testing can help develop international supply chains and enhance relationships with key trading partners.

319 IRENA (2020) Innovation outlook: Thermal energy storage. IRENA, Abu Dhabi.

320 Energy Consumers Australia (2020) Social licence for control of distributed energy resources: Final report. <https://energyconsumersaustralia.com.au/wp-content/uploads/Social-License-for-DER-Control.pdf> (accessed 24 October 2022).

Australia is currently participating in several international initiatives to address energy storage challenges. For example, Australia is a member of Mission Innovation, is co-leading the Clean Hydrogen mission, is set to co-lead the Net Zero Industries mission and is a participating member of the Green Powered Future mission.[321] Australia also holds several bilateral agreements with partner countries on low-emissions technologies.

There is an opportunity for Australian government, industry and research stakeholders to expand international engagement on energy storage technologies as global momentum grows, supported by a targeted and coordinated engagement strategy.

- Australia can benefit from identifying and clearly communicating its energy storage strategy, technology priorities, capabilities and activities to overseas stakeholders. This can help catalyse research and industry partnerships and investment in demonstrations and commercial deployments.
- In light of the volume and speed of global activity, careful consideration is required to focus engagement efforts towards countries, companies and institutions that share mutual interest and have strong activity in RD&D areas that are a priority for Australia.
- In order to successfully navigate overseas science, technology and innovation systems, industry and researchers will require a comprehensive understanding of the roles, decision making and funding capacities of key government, research and industry stakeholders.
- It is important for Australian industry and research stakeholders to adopt a coordinated approach to engaging overseas, through enabling agencies such as the Australian Trade and Investment Commission (Austrade) and the Department of Foreign Affairs and Trade (DFAT).

There are many avenues through which Australia can engage internationally. These are shown in Figure 37.

Figure 37: International engagement

	Key stakeholders	Engagement avenues	
Multilevel co-ordination	**Government** Signal intent and provide co-funding support	Bilateral and multilateral partnerships and dialogues (e.g. MoUs, Quad)	International organisation participation (e.g. IEA Energy Storage Technology Collaboration)
	Industry Develop best practice and undertake joint ventures	Business and industry consortia participation (e.g. Long Duration Energy Storage Council)	Joint RD&D projects Australian participation in overseas RD&D programs Foreign participation in Australian RD&D programs
	Research Collaborate to innovate	Researcher network associations	

MoUs, memoranda of understanding; RD&D, research, development and demonstration.

321 Mission Innovation (2022) Our members. Australia. <http://mission-innovation.net/our-members/australia/> (accessed 24 October 2022).

Cross-cutting R&D

The development of a decarbonised energy system underpinned by energy storage will require several cross-cutting R&D activities beyond any individual energy storage technologies discussed in this roadmap.

This report identifies four areas of cross-cutting R&D (Figure 38) that are vital to the development of energy storage technologies and their efficient deployment across Australia's energy system. These four areas are interrelated with each other, as well as with each energy storage technology, and should be undertaken in parallel and in a coordinated manner to ensure commercial viability, whole-of-system efficiency and environmentally and socially desired outcomes.

While beyond the scope of this report, further analysis should also be conducted to evaluate the RD&D priorities for individual storage technologies. Such analysis can help to prioritise RD&D investments that can provide incremental and stop-change cost reductions, in alignment with Australia's storage needs and comparative strengths and capabilities.

Figure 38: Cross-cutting R&D

Enabling science and technology

Research in information and communication technologies and material sciences that enable energy storage technology development and enable efficient use of storage.

Modelling

Use of cutting-edge modelling to inform decision making across technology design and energy system design.

Environmental and social

Research in environmental impacts of energy storage value chains, technology improvements for resource circularity, consumer behaviour and acceptance, and community engagment to inform technology development and decision-making.

Safety, security, standards and testing

Research and development of tools to manage technology safety and environmental risks, ensure cybersecurity across the energy system, and facilitate testing and certification to bring products to market.

Enabling science and technology

There are several cross-cutting science and technology domains that can enable significant advances in the design and use of energy storage technologies. Information and communication technologies (ICT) can enable better data collection, analysis and modelling to inform decision making, whereas material sciences enables the design and discovery of new materials to overcome technical barriers and deliver cost reductions and technology improvements.

CATEGORY	EXAMPLE R&D ACTIVITIES
ICT	• Data capture technologies such as sensors, the Internet of Things and other tracking tools can provide data feeds into storage asset monitoring and maintenance applications, as well as real-time data about end-user asset use. • Integrated data collection and management systems can enable the secure storage of energy data and perform data cleansing to feed into smart management of consumer- and utility-owned energy storage assets. • Artificial intelligence and machine learning can provide a range of decision-making support tools spanning from technology configuration through to energy policy. This can reduce design, testing and maintenance costs (e.g. using digital twins to simulate energy storage technologies or integrated systems and processes). This can also help uncover least-cost pathways to inform investments and policy (see Modelling). • Blockchain and ledger technologies can support environmental and social responsibility by tracking the provenance of energy storage materials, components and products. This can help underpin guarantee-of-origin schemes and promote Australian energy storage products as responsibly sourced and manufactured. • The development of digital platforms to allow industry stakeholders to access modelling tools and analyse energy storage technology systems for their own site-based energy requirements.
Material sciences	• Materials for high-temperature thermal storage and system components to improve charge and discharge efficiency, and to ensure plant reliability and lifetime. • Composite materials for cost-effective, high-pressure hydrogen storage tanks. • Novel cathode and anode materials for improved battery performance and to reduce costs and the use of critical minerals. • Improved construction materials for large systems, such as PHES, including resistance to wear and tear and events such as flooding.

Modelling

State-of-the-art modelling techniques can help improve knowledge across energy storage technologies and the energy system, deliver optimisation insights, inform decision making and reduce RD&D costs. Modelling tools can be used across a wide spectrum of applications, from the molecular level for developing novel energy materials through to the wider Australian energy system to inform policy choices.

Further, there are many different approaches that can be used which makes the modelling landscape complicated and highlights the need for further work in the area. For example, LCOS analysis is an extremely important tool in decision making but this project identified that there are different approaches and assumptions that can and are being used which could alter results and make comparisons difficult (see Section 3.1).

CATEGORY	EXAMPLE R&D ACTIVITIES
Economic modelling for valuation of energy storage and market design	• Measuring the economic value of services to the grid, industry and community, as well as the environmental and social value of decarbonisation, energy security and reliability. • Modelling the impact of policy and regulatory settings on the energy system and the viability of energy storage, including modelling of energy storage under different market conditions.
Techno-economic modelling of energy storage technologies, their integration into hybrid systems and plant configurations and energy system optimisation	• Improved and updated cost, performance and operational data collection across energy storage technologies as a key input to modelling, through stakeholder cooperation and ICT data collection tools (see ICT above). • Improved comparability between different energy storage technologies across end-use applications to assist technology choices, in particular, standardised and comparable approaches to LCOS. • Optimisation of energy storage deployment within evolving grid (including VRE, T&D and consumer-owned EV considerations). • Optimisation of thermal and/or electricity storage with industry site operations. • Optimisation of hybrid systems consisting of multiple energy storage technologies to provide a suite of services. • Modelling of sector coupling, including how gas, electricity, heat and transport infrastructure can be integrated with electrical, thermal and chemical storage. Modelling the role and impact of demand-side response by households and industry.
Climate modelling to inform long-term investment decisions	• Water forecasting to inform the deployment of PHES and hydrogen assets. • Temperature forecasting across geographical areas to inform planned battery projects (e.g. the performance of Li-ion batteries, typically deployed for 10–15 years, may be affected by hot climates or incur additional costs for cooling units). • Extreme weather event forecasting to inform multiday and seasonal capacity and energy requirements, T&D versus energy storage trade-off discussions and technology risks related to above-ground storage infrastructure.
Geographical and geological modelling	• Analysis of topographical characteristics suitable for PHES deployment. • Analysis of features such as solar radiance, wind speeds, water availability and proximity to ports and industrial clusters to inform deployments of green hydrogen production and storage. • Analysis of geological characteristics to map siting of underground hydrogen storage and A-CAES facilities.

Environment and social license

Environmental and social license research is essential for identifying and maximising the value of energy storage technologies beyond the economic dimension, and for minimising any adverse impacts arising from technology value chains. Further, social acceptance carries significant political weight and is key to effective deployment of energy storage across Australia.

CATEGORY	EXAMPLE R&D ACTIVITIES
Circular economy	• Lifecycle analysis to identify land, water and air impacts across energy technologies, as well as opportunities for improvement. Examples include embodied emissions within energy storage products and the amount of land and water required for storage projects.[322] • Stocks and flows modelling to identify key material bottlenecks and value streams of critical energy storage metals (e.g. cobalt and nickel), as well as opportunities to improve resource circularity. This can inform mineral extraction planning and scale up of recycling infrastructure. [323] • Minimising the impact of energy materials mining and processing via lower-impact processes and improved waste management (e.g. tailings reprocessing).[324] A circular economy requires the participation of and collaboration between stakeholders across the value chain; for example, there are opportunities to integrate energy storage product recycling with raw material processing. • Design to extend the durability of energy storage assets and enable the repair, second life and recycling of energy storage products. This includes research into novel materials, component design, safety for second-life use and recycling technologies.[325] • Design and development of best practice product stewardship schemes that include all suppliers across the value chain from raw materials to technology providers.[326] • Policy and regulatory research to improve the viability and effectiveness of e-waste and plan for future waste streams arising from the large-scale deployment of energy storage technologies. [327]
Social sciences research	• Pilot programs to analyse user behaviour with respect to energy storage use. For example, the South Australian smart charging trials in partnership with several industry players will use data from the trials to analyse the behaviour of commercial and individual drivers under different conditions, including pricing and user versus dynamic control.[328] • Qualitative approaches to understanding user perception of energy storage technologies, such as socioeconomic surveying methodologies. This can help inform and focus subsequent activities, such as media and communications. • Econometric studies measuring the socioeconomic impacts of the energy transition, namely the shift away from fossil fuel-based energy storage to low-emissions energy storage. This could include economic forecasting of structural unemployment trends and analysing the impacts of proposed policy solutions.

322 Florin N, Dominish E (2017) Sustainability evaluation of energy storage technologies. Institute of Sustainable Futures. <https://acola.org/wp-content/uploads/2018/08/wp3-sustainability-evaluation-energy-storage-summary.pdf> (accessed 24 October 2022).

323 Bruce et al. (2021) Critical energy minerals roadmap. CSIRO, Australia.

324 Bruce et al. (2021) Critical energy minerals roadmap. CSIRO, Australia.

325 Bruce et al. (2021) Critical energy minerals roadmap. CSIRO, Australia.

326 Bruce et al. (2021) Critical energy minerals roadmap. CSIRO, Australia.

327 Environment and Communications References Committee (2018) Never waste a crisis: the waste and recycling industry in Australia. <https://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Environment_and_Communications/WasteandRecycling/Report> (accessed 24 October 2022); Laviano H, Barlow J, Ton M, Dawood N (2017) An inquiry into the waste and recycling industry in Australia: A submission to the Environment and Communications References Committee. Submission to the Senate Inquiry. Submission 63. <https://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Environment_and_Communications/WasteandRecycling/Submissions> (accessed 24 October 2022).

328 Government of South Australia (2022) Smart charging trials. <https://www.energymining.sa.gov.au/industry/modern-energy/electric-vehicles/smart-charging-trials> (accessed 24 October 2022).

Safety, security and standards

Safety, standards and testing are essential for protecting consumers of energy storage products, society and the environment by setting formal benchmarks for responsibility. Testing and certification are also essential to accelerating the development and commercialisation of energy storage products, particularly for domestic technology proponents.

CATEGORY	EXAMPLE R&D ACTIVITIES
Safety and security	• Developing tools to support the monitoring and maintenance of energy storage assets, such as predictive modelling and sensing technologies. • Cybersecurity research to improve the mitigation of cyberattacks on utility scale and distributed energy storage resources across the energy system to protect public infrastructure.[329]
Standards	• Developing standards across energy storage technologies to capture new developments and ensure consumer safety and environmental and social standards across the value chain. This includes standards across the energy storage supply chain from the sustainable mining of key energy storage minerals (e.g. cobalt for batteries) through to processing, manufacturing, use and end of life. • Developing standards pertaining to infrastructure and consumer homes to futureproof the energy market for increased uptake of energy storage products (e.g. ensuring buildings have the capacity to integrate EV charging and V2G technology, and updating emergency protocols with respect to thermal runaway events). This includes researching best practices globally, aligning with technology trends and analysing needs within the Australian context. • Developing provenance frameworks and certification schemes for energy storage materials and components, and developing associated tools, such as blockchain and ledger technologies (see ICT discussed earlier).

329 Hupp W, Saleem D, Peterson JT, Boyce K (2021) Cybersecurity certification recommendations for interconnected grid edge devices and inverter based resources. National Renewable Energy Laboratory. <https://www.nrel.gov/docs/fy22osti/80581.pdf> (accessed 24 October 2022).

Appendices

Appendix A: Stakeholder groups consulted

Industry, government and research

1414 Degrees

AGL

Alcoa

AMPOL

Australian National University (ANU)

Australian Pipelines and Gas Association (APGA)

Australian Academy of Technology and Engineering (ATSE)

Australian Vanadium Limited

Clean Energy Finance Corporation (CEFC)

ClimateWorks Australia

Department of Climate Change, Energy, the Environment and Water (DCCEEW)

Energeia

Energy Queensland

Energy Vault

ENGIE

EV Council

First Nations Clean Energy Network (FNCEN)

Fortescue Future Industries (FFI)

Future Battery Industries (FBI) CRC

Future Fuels CRC

Genex

GHD

Graphite Energy

Heavy Industry Low-carbon Transition (HILT) CRC

Hydro Tasmania

Highview power

Horizon Power

Hydrostor

Hyundai

International Energy Agency (IEA)

Incitec Pivot

Innovative Manufacturing (IM) CRC

ITP Thermal

JET Charge

LAVO

Magellan Power

MGA Thermal

OZ Minerals

QLD Department of Agriculture and Fisheries

Queensland Farmers Federation

RayGen

Rio Tinto

Sun Cable

Tesla

Transgrid

Tritium

Vast Solar

University of Wollongong (UOW)

VSUN Energy

CSIRO

Adam Best

Adrien Guiraud

Andrew Beath

Andrew Jenkin

Andy Ross

Ben Clennell

Chris Vernon

Daniel Roberts

Greg Wilson

Jason Czapla

Jerad Ford

Jim Patel

Jim West

Judy McShane

Kate Cavanagh

Keith Vining

Matt Ironside

Max Temminghoff

Michael Battaglia

Nawshad Haque

Patrick Hartley

Paul Savage

Phillip Paevere

Sam Behrens

Stephen Craig

Tim Jones

Vicky Au

Warren Flentje

Wes Stein

Yen Soo Too

Appendix B: Storage demand modelling approach

Updates since AEMO's 2022 ISP

The following model inputs have been updated since the AEMO's 2022 ISP:

- capital cost estimates for electricity generation, storage and hydrogen production technologies, which are now consistent with GenCost 2021–22[330]
- coal plant closure dates for Bayswater, Eraring and Mt Piper
- CSIRO estimates on EV/fuel cell electric vehicle (FCEV) uptake.
- industry electrification: The *Step Change* scenario previously considered relatively unconstrained electrification in industry, mainly controlled via hurdle rates. The implementation of the *Step Change* scenario in this publication includes stricter maximum electrification uptake rates for several industry sectors to better incorporate end-of-life equipment turnover.

There are a number of recent developments that have not been incorporated into the modelling approach, some of which could accelerate the uptake of renewable energy storage. These include:

- The Australian Government's target of a 43% reduction in emissions by 2030 relative to 2005 levels; however, this does not affect the outlook because net zero emissions pathways are similar or more ambitious than the target.
- Recent changes to 2030 renewable electricity targets at the state and federal levels. These could result in higher VRE shares being achieved by 2030 than in the modelled scenarios.
- Renewable energy storage targets and projects, such as targets recently announced in Victoria, and the Pioneer-Burdekin and Borumba Dam PHES projects in Queensland,[331] which could lead to higher uptake of electricity storage in the near term than in the modelled projections.
- Earlier coal retirements and higher gas prices on the east coast since the beginning of the conflict in Ukraine, which could accelerate the transition to renewables faster than the modelling has indicated.

Electricity storage

The electricity storage demand projections are estimated using CSIRO's *Multi-sector Energy Modelling*[332] approach, which was also employed to develop the *Step Change* and *Hydrogen Superpower* scenarios outlined in the 2022 Integrated System Plan for the NEM. This roadmap also reports the storage estimates for WA, using the same 2022 ISP scenario assumptions.

The modelling approach estimates the impact on electricity storage consistent with an estimated level of VRE. This level of VRE is based on the least-cost abatement required to meet a national emissions budget (rather than jurisdictional budgets). The emissions budget is consistent with Australia's 'fair share' in limiting global temperatures to between 1.5–2 degrees by 2100 (depending on scenario), as well as other constraints (such as volume of hydrogen exports).

330 Graham P, Hayward J, Foster J, Havas L (2022) GenCost 2021–22: Final report. CSIRO, Australia. doi:10.25919/mb22-c107

331 Andrews D (2022) Australia's biggest renewable energy storage targets. <https://www.premier.vic.gov.au/australias-biggest-renewable-energy-storage-targets> (accessed 24 November 2022); Department of Energy and Public Works (2022) Pioneer-Burdekin pumped hydro energy storage. Queensland Government. < https://www.epw.qld.gov.au/about/initiatives/pioneer-burdekin-pumped-hydro-energy-storage> (accessed 24 November 2022); Department of Energy and Public Works (2022) Borumba Dam pumped hydro. Queensland Government. <https://www.epw.qld.gov.au/about/initiatives/borumba-dam-pumped-hydro> (accessed 24 November 2022).

332 Reedman L, Chew MS, Gordon J, Sue W, Brinsmead T, Hayward J and Havas L (2021) Multi-sector energy modelling. CSIRO and Climateworks. <https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf>

The pathways for electricity storage demand in the net zero scenarios considered are estimated using two least-cost modelling approaches: [333]

- **AusTIMES:** A full energy systems model that simultaneously determines the fuel and technology choices of the electricity, hydrogen production and end-use sectors, including transport, buildings, industry and agriculture.
- **STABLE:** An electricity sector model designed to determine the additional supporting technologies (including storage systems) that should be deployed to meet different levels of variable renewable energy.

Storage durations available for selection by the model were whole numbers between 1 and 48 hours depending on the storage technology: li-ion battery storage at 1, 2, 4, or 8 hours; VRFB storage at 4, 8, 12 or 24; A-CAES at 8, 12, 24 or 48; and PHES at 6, 8 12, 24 or 48. A CST plant option with a 12 hour storage duration profile was modelled. Modelling also includes a small number of specific projects such as the 168 hour duration Snowy 2.0 project in New South Wales, the 24 hour duration Cethana project in Tasmania, and the 8 hour duration Kidston project in Queensland.

Further details on each modelling approach, as well as the combination of these approaches for estimating Australia's electricity storage requirements, are provided below.

AusTIMES

AusTIMES is an Australian implementation of The Integrated MARKAL-EFOM System (TIMES), a full energy systems model that satisfies energy services demand at the minimum total system cost, subject to physical, technological and policy constraints.

AusTIMES develops sectoral pathways for emissions and fuel use, at annual frequency, out to 2050. Key outputs include electricity demand by primary energy source (e.g. coal, natural gas, oil, solar and wind), as well as fuel demand in end-use sectors by source (e.g. coal, natural gas, oil and electricity). The model covers all states and mainland territories.

Primary sources for data inputs into AusTIMES come include:

- AEMO ISP 2021–22 inputs and assumptions workbooks for technology costs, capacity factors, regional reserves, greenhouse gas emissions factors, national and state energy policy impacts (including coal retirements).[334]
- WA Government policy announcements, such as state-owned coal shutdown by 2030.[335]
- CSIRO emission constraints (based Australia's 'fair share' of Intergovernmental Panel on Climate Change [IPCC] global carbon budgets).[336]
- CSIRO 2021–22 GenCost for plant capital cost inputs.[337]

For more detail on the structure of the AusTIMES model, see the *Multi-sector Energy Modelling report*.[338]

333 The least cost modelling approach provides an indication of the most economically viable storage options. However, like all modelling, the analysis is a simplification of the investment environment and should not be relied upon as the only source of information on viability of storage technologies. The modelling does not include all the possible system outages and extreme weather that are considered in larger modelling projects such as the AEMO ISP. These events could represent additional opportunities for storage to play a direct supply or insurance role. To partially address this issue, we have benchmarked the results against AEMO ISP modelling results where possible. The reader should also be aware that there are likely to be further government interventions and market developments that are not captured in the scenarios and assumptions applied in the modelling.

334 AEMO (2022) Current inputs, assumptions and scenarios: 2022 Forecasting Assumptions Workbook. < https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios > (accessed 13 December 2022).

335 Government of Western Australia (2022) State-owned coal power stations to be retired by 2030 with move towards renewable energy. <https://www.wa.gov.au/government/announcements/state-owned-coal-power-stations-be-retired-2030-move-towards-renewable-energy> (accessed 19 October 2022).

336 LDES, McKinsey & Company (2021) Net-zero power: Long-duration energy storage for a renewable grid. <https://www.mckinsey.com/capabilities/sustainability/our-insights/net-zero-power-long-duration-energy-storage-for-a-renewable-grid> (accessed 24 October 2022).

337 Graham et al. (2022) GenCost 2021–22: Final report. CSIRO, Australia. doi:10.25919/mb22-c107

338 Reedman et al. (2021) Multi-sector energy modelling. CSIRO and Climateworks. <https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf>

STABLE

The STABLE (A Spatial Temporal Analysis of Balancing Levelised-Cost of Energy) model draws on the open source DIETER model for its basic structure, and is modified to incorporate the design of electricity markets in Australia. It includes the NEM and WA markets, considering the SWIS, NWIS, inland Pilbara, Gascoyne–Mid-West and Goldfields–Esperance area in the latter.

STABLE is an 'intermediate horizon' model that straddles the contrasting approaches of dispatch models and generation expansion models. Dispatch modelling focuses on the detailed operation of existing plants and capacities in a time resolution from minutes to subsets of an hour. This provides an estimate of balancing solutions (transmission, storage and other flexible generation) required to meet security and reliability requirements at a given level of VRE penetration.

Generation expansion modelling focuses on the optimisation of investment in balancing solutions over annual time frames. By combining these two approaches, the intermediate horizon model looks to co-optimise investment in balancing solutions in the presence of system reliability considerations. It also estimates the size and utilisation of power plants required to meet hydrogen production targets in a least-cost manner.

Various constraints are implemented to ensure the solution satisfies operational requirements at least cost. These include energy demand balance, capacity limits in the generation and transmission of power, ramping limits, operating reserves, minimum stable operations, hydroelectric storage inflows, inertia requirements, storage dynamics and renewable energy targets. Constraints are also placed on investment in new generation, storage, system strength and transmission technologies. Further, specific constraints are imposed for known energy generation/storage projects at the time of their expected commissioning (e.g. Snowy Hydro 2.0 is projected to come online in December 2026).

Primary sources for data inputs into STABLE come from the following:

- AEMO ISP 2021–22 inputs and assumptions workbooks.[339]
- the Government of Western Australia's Whole of System Plan.[340]
- AEMO variable renewable energy availability profiles (trace data)[341] and internal CSIRO tools for half-hourly demand profiles.
- CSIRO 2020–21 GenCost outputs for plant capital cost inputs.[342]
- AusTIMES electricity generation, gas plant retirement and hydrogen production profiles.

Modelling process

The storage demand projections were developed using the following process:

1. The impact on Australia's full energy system was modelled for each scenario in AusTIMES, drawing on key inputs such as emissions constraints, policy impacts, technology costs and plant capital costs. The annual outputs generated in AusTIMES that are used for the storage projections include electricity generation, gas plant retirements and hydrogen production by technology (polymer electrolyte membrane/alkaline electrolysis).

2. Electricity generation is converted to a half-hourly time series using CSIRO's internal tools and AEMO renewable energy traces.

3. The outputs generated from Steps 1 and 2, as well as a range of other inputs (including DER for solar PV, EVs and home batteries, and plant capital costs) are run through STABLE. This process estimates the level and timing of VRE supply, which is then used to estimate the size and duration of energy supply shortfalls, and therefore determine electricity storage requirements by duration.

The modelling process is illustrated in Figure 39.

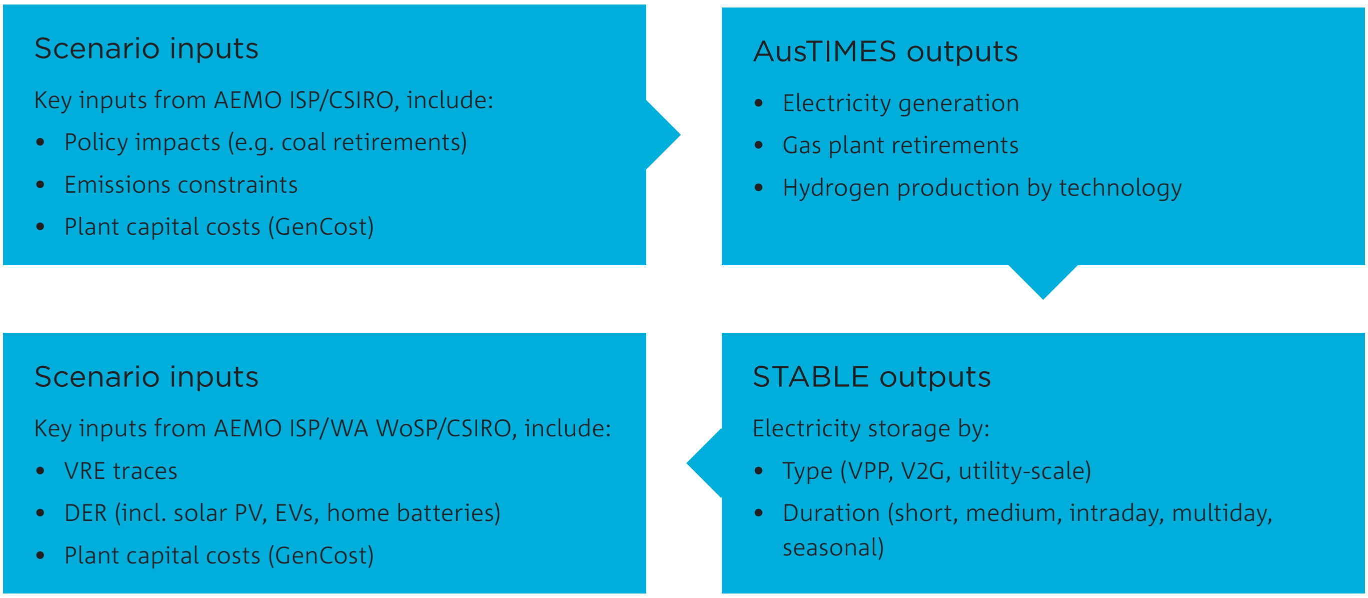
339 AEMO (2022) Current inputs, assumptions and scenarios: 2022 Forecasting Assumptions Workbook. < https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios > (accessed 13 December 2022).

340 Government of Western Australia (2020) Whole of System Plan <https://www.wa.gov.au/government/document-collections/whole-of-system-plan> (accessed 13 December 2022).

341 AEMO (2022) Current inputs, assumptions and scenarios: Demand trace data. < https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios > (accessed 13 December 2022).

342 Graham et al. (2022) GenCost 2021–22: Final report. CSIRO, Australia. doi:10.25919/mb22-c107

Figure 39: Storage demand modelling process



Terminology: AEMO, Australian Energy Market Operator; DER, distributed energy resources; EVs, electric vehicles; ISP, Integrated System Plan; PV, photovoltaic; V2G, vehicle to grid; VPP, virtual power plant; VRE, variable renewable energy; WA, Western Australia; WoSP, Whole of System Plan.

Further details on the assumptions for specific storage types are summarised below:

Customer (non-VPP) storage: This is not included in the STABLE modelling process, but rather sourced from AEMO's 2022 ISP.

Customer (VPP) storage: This is aligned to the projections from AEMO's 2022 ISP and incorporated into STABLE to estimate total requirements for utility scale storage.

Customer (V2G) storage: Projections for light EV projections are sourced from AEMO's 2022 ISP scenario (approximately 20 million light vehicles nationally in 2050 in both the *Step Change* and *Hydrogen Superpower* scenarios) and combined with other AEMO assumptions to estimate the capacity available for coordinated storage.

In the *Step Change* scenario, 14% of EVs are assumed to be participating in the V2G scheme by 2050. Of those participating in the scheme, it is assumed that 50% of battery capacity can be used (the remainder needs to be available for travel purposes) and 50% of vehicles are connected to the grid at any one time. As a result, this scenario assumes that 3.6% (or 7.5 GW/67 GWh across the NEM and WA by 2050) of EV capacity can be used for electricity storage purposes.

In the *Hydrogen Superpower* scenario, 17% of EVs are assumed to be participating in the V2G scheme, again with 50% battery capacity that can be used and 50% of vehicles being connected to the grid at any one time, which yields 8.7% of EV capacity or 9 GW/81 GWh.

Utility scale storage: Planned projects that are assumed to be taken up in the model include the Snowy 2.0 (2,000 MW), Kidston (250 MW) and Cethana (750 MW) PHES projects, and 700 MW of short-duration utility scale storage. The additional storage capacity requirements are estimated based on the size and duration of energy supply shortfalls in STABLE.

Core scenarios

Step Change scenario

The *Step Change* scenario sees a consistent and fast-paced transition from fossil fuels to renewable energy through coordinated economy-wide action. It assumes significant change in global policy commitments, consistent with limiting global temperature increases to below 2°C by 2100, alongside a falling cost of VRE and energy storage, as well as an increase in digitalisation to support demand management and grid flexibility.

Efficiency is considered as important as electrification, with a large decrease in energy consumption driven by technology breakthroughs in energy efficiency and fuel switching, increasing the productivity of energy use. The scenario sees higher levels of electrification for end-use sectors such as heating and transport.

Given some processes in industry cannot be easily electrified, some industry sectors continue to draw on fossil fuels. These sectors are typically classified as 'hard to abate' due to the presence of chemical reactions that generate CO_2 (i.e. cement) or their current reliance on fossil fuels for high-temperature heat (i.e. alumina, iron and steel; manufacturing) or a source of carbon or hydrogen (i.e. plastics and chemicals industries).[343]

Finally, this scenario sees an increase in land-based CO_2 sequestration to offset the continued positive emissions in hard-to-abate industry sectors.[344]

Hydrogen Superpower scenario

In the *Hydrogen Superpower* scenario, global policy ambition is stronger, with low-cost VRE leading to higher electricity demand and hydrogen production relative to the *Step Change* scenario. In this pathway, global policy action is consistent with limiting global temperature increases to 1.5°C by 2100.

There is strong domestic economic growth and Australia leverages its competitive advantages to grow the economy through green hydrogen and other low-emissions exports, such as hydrogen-based direct reduced iron steel. The production of hydrogen is projected to reach 2,845 PJ/20 Mt by 2050, compared with 740 PJ/5 Mt in the *Step Change* scenario.[345] Hydrogen exports are assumed to be around 2,175 PJ/15 Mt in 2050, compared with 590 PJ/5 Mt in the *Step Change* scenario. Given the electricity required to produce this level of hydrogen and other green exports, total generation increases sixfold between 2020 and 2050.

There are various other differences between the *Hydrogen Superpower* and *Step Change* scenarios. First, there is greater shift to electricity industry under the *Hydrogen Superpower* scenario. In addition, although the improvement in energy efficiency is still large under the *Hydrogen Superpower* scenario, there is less improvement relative to that under the *Step Change* scenario. Finally, given the higher level of policy ambition, the *Hydrogen Superpower* scenario sees a greater level of land-based CO_2 sequestration up to 2040.

For more details on scenario input assumptions, see CSIRO's Multi-sector Energy Modelling report.[346]

343 Other factors that can make emissions within a sector hard to abate include a long lifetime for fossil fuel-based capital assets and exposure to highly competitive global markets: IEA (2020) Energy technology perspectives. <https://www.iea.org/reports/energy-technology-perspectives-2020> (accessed 28 November 2022).

344 The balance between land-based CO_2 sequestration and industrial emissions has implications for energy storage because higher (lower) industrial emissions (and therefore higher [lower] land-based CO_2 sequestration to meet net zero) translate into lower (higher) electricity use.

345 For comparison, Australia's current liquefied natural gas production is 4,576 PJ/88 Mt per year.

346 Reedman LJ, Chew MS, Gordon J, Sue W, Brinsmead TS, Hayward JA, Havas L (2021) Multi-sector energy modelling. CSIRO, Australia.

Sensitivities

In addition to the core scenarios, the analysis conducted two sensitivities on the *Step Change* and *Hydrogen Superpower* scenarios for key inputs that could affect the outlook for electricity storage. The descriptions and impacts estimated in these sensitivities are provided below.

Low Coordinated DER sensitivity

The Low Coordinated DER sensitivity shows that the risk associated with fewer customers being dynamically operated to support the grid is minimal because the additional utility scale storage required to offset the reduction is small.

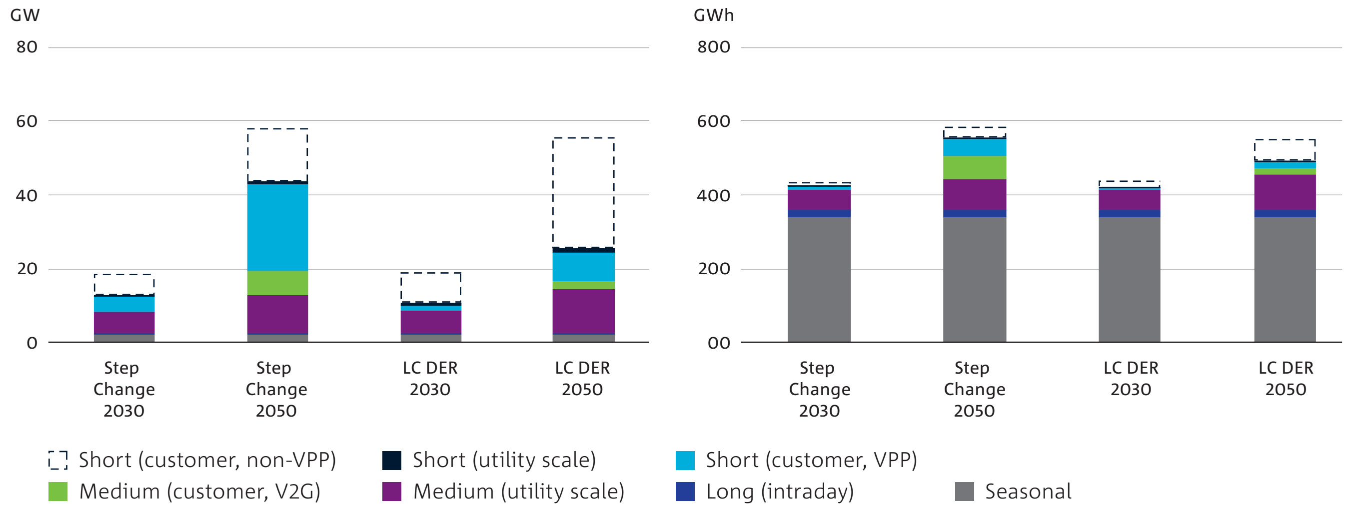
This sensitivity investigates the implications for utility scale storage demand when a large proportion of customers choose not to have their home batteries or EVs dynamically coordinated by the grid.[347] In particular, customer-owned storage coordinated by the grid (VPP and V2G) is reduced by two-thirds relative to the *Step Change* scenario.

Although the VPP reduction is lost from the power system as a dynamically coordinated resource, the V2G reduction is allocated to customer (non-VPP) storage, and statically controlled by home battery owners.

As a result of this shift, total dispatchable storage (which excludes customer, non-VPP storage) will be lower and the NEM will need to build some additional medium-duration utility scale storage to partially offset the reduction in coordinated DER. However, the model results suggest that the increased requirement for utility scale storage is small and, given this is assumed to have a higher rate of utilisation than customer storage, the overall storage capacity requirements in the NEM decrease slightly (Figure 40).[348]

The sensitivity suggests that if small-scale customer batteries are made less available in the NEM, utilities can replace them with a much lower level of utility scale storage capacity. However, small-scale customer batteries will still be useful if they are made available to the system because this will lower the overall cost of storage for utilities.

Figure 40: NEM storage capacity, *Step Change* scenario and *Low Coordinated DER* sensitivity



Notes: Estimates are based on a least-cost modelling approach to achieve net zero emissions at a national level, rather than a jurisdictional level. Dashed bars reflect customer (non-VPP) storage sourced from AEMO's 2022 ISP. Terminology: AEMO, Australian Energy Market Operator; DER, distributed energy resources; ISP, Integrated System Plan; LC, low coordinated; NEM, national electricity market; V2G, vehicle to grid; VPP, virtual power plant.

347 When storage is coordinated by the electricity grid in real time, it is assumed to optimise benefit for the grid and the device owner. When a storage device is not coordinated by the grid, it is assumed to minimise customer bills, relative to an annual retail contract price (including time of use).

348 Although under the *Step Change* scenario the grid can coordinate customer storage more efficiently than in the *Low Coordinated DER* sensitivity, the reliability of communications with customer-owned batteries is such that the grid cannot fully utilise this storage capacity (85% of customer storage is assumed to be used). That is, the available customer storage capacity is derated by 15% because trials have shown that the communications to customer batteries will be affected by interruptions. However, under the *Low Coordinated DER* sensitivity pathway, grid operators have full control over the additional large-scale storage capacity, resulting in higher utilisation rates, and therefore lower storage needs in total.

Low-Cost Hydrogen Storage sensitivity

The Low-Cost Hydrogen Storage sensitivity illustrates that at high levels of hydrogen production, lowering the cost of storing hydrogen could have a large impact on the demand for electricity storage.

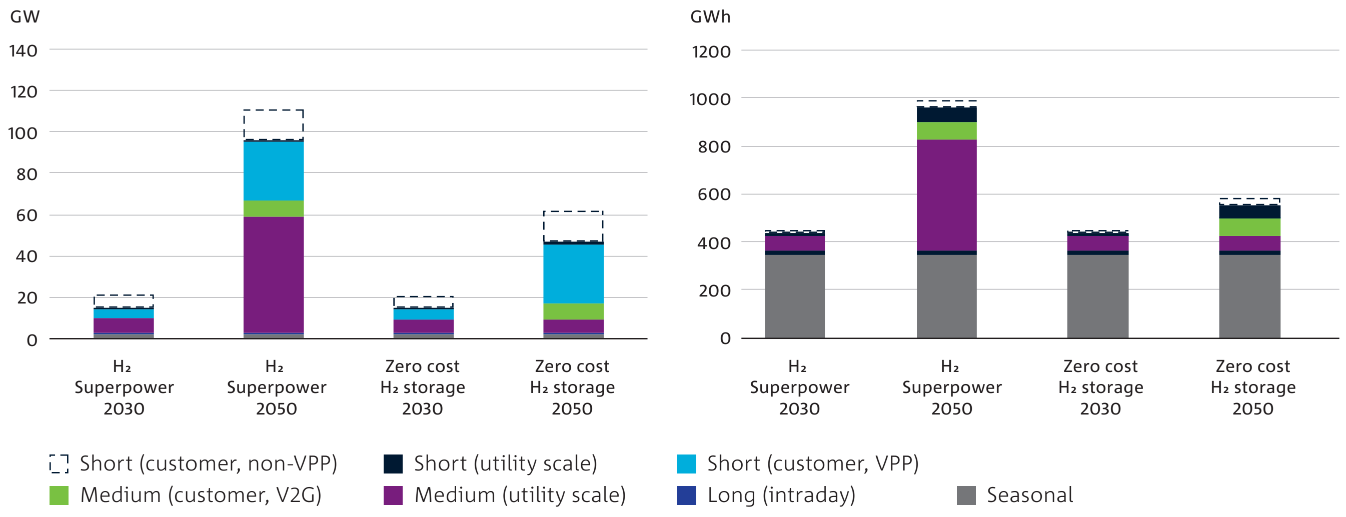
This sensitivity is applied to the *Hydrogen Superpower* scenario to examine the impact of hydrogen storage costs on the need for electricity and hydrogen storage. The exercise estimates the impact on electricity storage in an extreme case, where the same hydrogen production target is achieved, but with hydrogen storage available at a very low cost.

Given end users of hydrogen require electricity supply at a relatively constant rate, when using VRE, producers will either need to deploy electricity storage before the actual production process or ramp electrolysers up and down depending on renewable energy availability, and then store the produced hydrogen in pipelines, tanks or underground.

Although both electricity and hydrogen storage systems will be required in the production process, a higher uptake of hydrogen storage can translate into lower electricity storage requirements.

In this sensitivity, following the removal of hydrogen storage costs, it is most cost-effective to reduce the use of electricity storage, increase capital spending on electrolysers and lower capital utilisation rates. Across the NEM, this leads to a reduction in dispatchable electricity storage from 96 GW/950 GWh (*Hydrogen Superpower* scenario) to 47 GW/550 GWh (see Figure 41). This illustrates that the costs of storage (in various forms) can have significant implications for the electricity storage required in the NEM to produce large amounts of hydrogen.

Figure 41: NEM Storage capacity, *Hydrogen Superpower* scenario and *Low-Cost Hydrogen Storage* sensitivity



Notes: Estimates are based on a least-cost modelling approach to achieve net zero emissions at a national level, rather than a jurisdictional level. Dashed bars reflect customer (non-VPP) storage sourced from AEMO's 2022 ISP. Terminology: AEMO, Australian Energy Market Operator; ISP, Integrated System Plan; V2G, vehicle to grid; VPP, virtual power plant.

Thermal storage approach

This work did not cover detailed modelling for storage systems outside of electricity storage. However, a simple approach was developed to estimate renewable thermal energy storage in the *Hydrogen Superpower* scenario in 2050, using the following approach:

$$Elec_{2050,heat} = (Share\_Elec_{2050} - Share\_Elec_{2020}) * Elec_{2050} * Share\_Energy_{2050,heat}$$

$$TES\_Cap = \frac{Elec_{2050,heat}}{365} * duration$$

where:

- TES_Cap is thermal energy storage capacity (GWh)
- $Elec_{2050,heat}$ is electricity used for process heat in 2050
- *duration* reflects the number of hours the fully charged system can sustain output at its specified power level (12 in this example)
- $Share\_Elec_t$ is the share (%) of electricity use in industry final energy in year *t*, sourced from AusTIMES model
- $Elec_{2050}$ is electricity use (PJ converted to GWh), sourced from AusTIMES model
- $Share\_Energy_{2050,heat}$ is the share (%) of energy used for process heat in total industry energy. An estimate of 55% in 2020 is taken from Lovegrove et al (2019), and is assumed to remain constant to 2050.[349]

349 Lovegrove et al. (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/knowledge-bank/renewable-energy-options-for-industrial-process-heat/> (accessed 21 October 2022).

Appendix C: Levelised cost of storage approach

There are variations in the methodology for determining the LCOS which can lead to different results across sources. This study employs the approach developed by Schmidt et al (2019) *Projecting the Future Levelized Cost of Electricity Storage Technologies.*[350]

LCOS calculation

The LCOS measures the present value of all costs incurred over the life of the asset divided by the present value of the stored energy dispatched over the life of the asset. Costs consist of capital costs, cost of the energy to charge the system and other fixed and/or variable operating costs. Equations 1 to 5 illustrate the LCOS formulae for electricity storage. The formulae are similar for thermal storage except for the discharge of thermal energy. See *LCOS for CST and storage* section for further information. Charging costs are discussed further in the *Model assumptions* section.

$$LCOS\left[\frac{\$}{MWh}\right] = \frac{\sum_{t=1}^{n}\frac{Capital\ Cost_t + O\&M\ Cost_t + Charging\ Cost_t}{(1+d)^t}}{\sum_{t=1}^{n}\frac{E_{Dis,t}}{(1+d)^t}} \quad \text{Equation 1}$$

$$Charging\ Cost_t = \frac{E_{Dis,t} * C_e}{RTE} \quad \text{Equation 2}$$

$$\sum_{t=1}^{n}\frac{E_{Dis,t}}{(1+d)^t} = P * H * C * \sum_{t=1}^{n}\frac{(1-d_{Cycle})^{(t-1)*\Sigma Cycles}}{(1+d)^t} \quad \text{Equation 3}$$

where:

- *LCOS* is the levelised cost of storage
- *t* is the year of operation, t= 1 is when construction starts
- Capital Cost is the cost for any capital payments in year t, which may include loan repayments
- O&M is the fixed operating and maintenance costs
- *n* is the life of system, either economic or technical (years)
- *d* is the discount rate (% pa)
- $E_{Dis,t}$ is the electricity discharged in year t (kWh/year)
- *H* is the duration of storage (hours)
- *RTE* is the round-trip efficiency (%)
- C_e is the cost of input energy (\$/kWh)
- *P* is the power of system (kW)
- *C* is the cycles per year
- d_{Cycle} is the degradation per cycle (%)
- Σ*Cycles* is the total number of cycles that the system has been through.

350 Schmidt et al. (2019) Projecting the future levelized cost of electricity storage technologies. Joule 3, 81–100.

Calculation of Cycle Degradation

The cycle degradation is modelled as a geometric sequence representing the degradation that occurs during each cycle to the maximum specified lifetime cycles. At the end of life, the degradation impact is such that capacity equals 80% of the original capacity. The value of 80% was taken from the study 'Projecting the Future Levelized Cost of Electricity Storage Technologies'.

$$C_{t_0}\left(1 - d_{cycle}\right)^{Cycle_{Life}} = 80\% * C_{t_0}$$

Rearranging

$$d_{cycle} = 1 - e^{\frac{\ln(0.8)}{Cycle_{Life}}} = 1 - 80\%^{\frac{1}{Cycle_{Life}}}$$

where:

C_{t_0}	Initial capacity of the system	MWh or kWh
d_{cycle}	Degradation per cycle	$\%_{\text{Capacity}}$/Cycle
$Cycle_{Life}$	Total lifetime cycles of the technology	#

So, if a technology has a total expected lifetime of 5,000 cycles, then

$$d_{cycle} = 1 - 80\%^{\frac{1}{5{,}000}} = 0.0045\%$$

Model assumptions

Unless stated otherwise, the following general assumptions were used across technologies in the LCOS analysis:

- **System size:** The assumed system size reflects current projects for 2025 estimates and anticipated projects for 2050 estimates.
- **End-of-life costs:** Not included.
- **OPEX:** This has been standardised at 1% of total CAPEX per year across technologies based on an average of operating cost assumptions from the literature and stakeholder feedback. For emerging technologies, the capital costs are higher, so this takes into account the likelihood of higher OPEX for emerging technologies as well.
- **CAPEX:** The capex is the sum of a CAPEX contribution linked to the power level of the system plus a contribution linked to its total capacity for storing energy. The capital cost of the system that provides the charging energy (e.g. PV) is omitted. Instead, the price of electricity is specified and used in the calculations. Similarly, for systems that have thermal energy as an input, the cost of thermal energy is specified.
- **Charging costs:** These costs relate to a standalone storage systems to enable comparison between different storage types and fossil fuel alternatives. The unit cost of energy is multiplied by the energy required to charge the system, as well as any losses incurred during the charge and discharge cycles based on RTE. For example, if the RTE is 80%, then the charging cost reflects 1.25 kWh of electricity for every 1 kWh discharged.
- **Gas Prices:** This report has elected to exclude the recent gas price volatility in the analysis. Therefore, the gas price projections do not reflect a continuation of the high gas prices seen in 2022.
- **Taxes and inflation:** For simplicity, these have not been incorporated so the estimates should be interpreted on a pre-tax basis, in 2022 prices.

Table 15 provides a summary of other key model assumptions used across the LCOS analysis.

Table 15: Economic and model assumptions

VARIABLE	UNIT	2025	2050
Gas price	$/GJ	11.35	13.65
Electricity price	¢/kWh$_e$	6.00	4.00
Heat price[351]	¢/kWh$_{th}$	3.9	1.95
Discount rate[352]	%	6.00	
Length of loan	Years	15.00	

Storage applications

The LCOS analysis has been aligned to specific applications summarised in the Table 16.

For the major grids LCOS analysis, the energy storage capacity factors by technology and duration were taken from the demand modelling framework. These capacity factors, which reflect VRE availability across transmission zones, were used to estimate the number of full cycles per year for each storage technology and duration.[353] The values were calculated for each transmission zone, and the average values for the whole of Australia were used as an input into the LCOS calculations. It is important to note that the cycles identified represent the number of times a storage type is fully charged or discharged annually, and that it is acknowledged that partial charging and discharging can occur on a daily basis.

For remote mining and remote communities, the (Hybrid Optimization of Multiple Energy Resources) HOMER modelling package was used to identify the storage durations and annual cycles that were being met through the use of diesel generators. See Appendix D for details on the approach and case studies analysed.

Table 16: Specific applications (durations and cycles) explored in this roadmap

REPORT SECTION	APPLICATION EXAMPLE	DURATION (HOURS)	CYCLES (PER YEAR)
Major grids (Section 3.2)	Short duration	2	394
	Medium duration	8	230; 285
	Long intraday	24	117
	Long multiday	48	68
Large-scale, isolated grids: Remote mining (Section 3.3)	Long multiday	36	52
Isolated microgrids: Remote communities (Section 3.4)	Long multiday – strong wind resources	48	20
	Long multiday – strong solar resources	163	14

351 For more details, see LCOS for CST and Storage at the end of this appendix.

352 Department of the Prime Minister and Cabinet, Office of Best Practice Regulation (2016). Cost–benefit analysis guidance note. <https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwjzpNXQuM_7AhXxHrcAHRysC70QFnoECBEQAQ&url=https%3A%2F%2Fwww.pmc.gov.au%2Fsites%2Fdefault%2Ffiles%2Fpublications%2Fcosst-benefit-analysis.docx&usg=AOvVaw1sRzvu6v94mm2sFPBvQLFz> (accessed 28 November 2022).

353 Where the technology was not present in the demand modelling, capacity factors from other technologies were used.

Technology assumptions applied to storage applications

Eight technologies were analysed based on stakeholder feedback and available data; eight related to electrical applications and two to thermal applications. In most cases, the technologies are based on information sourced from CSIRO GenCost 2021–22.[354]

Table 17 provide summaries of the key economic and technical parameters used for the LCOS analysis for storage applications (discussed earlier).

Only costs related to storage has been included in the LCOS analysis. This means the cost of either electricity or heat into and/or out of storage has been included, but the cost of external transmission/pipeline or other infrastructure has not. Boundary diagrams are provided in the next section for each technology to help communicate the cost elements that have been included. It is acknowledged that there are various configurations and site-based implications of each technology that can change underlying costs.

LCOS for CST storage

To allow comparison with other electrically charged systems, CST storage uses a heat input price (see model assumptions) based on a levelised cost of heat. The following section provides additional details on cost assumptions.

Power capital costs

The power capital costs (PCC) consist of only the final conversion of heat to electricity, including the power block, boilers, heat exchangers and other balance of plant (BOP). The solar field cost is explicitly excluded from the costs. Instead, a cost for heat input is used to align it with the electrical cases. The costs are from ARENA's *Comparison of Dispatchable Renewable Electricity Options*.[355]

Table 17: Economic and technical parameters for the roadmap LCOS analysis

Case	Parameter	Unit	Li-ion batteries	Redox batteries	PHES	A-CAES	eTESe	CST storage	H_2 – tank	H_2 – geological
2025	Cycle life	Total cycles	6,000	18,000	30,000	30,000	30,000	30,000	15,000	15,000
	Technical life	Years	15	20	35	35	35	35	35	35
	Round-Trip Efficiency	%	81	66	75	60	42	42	31	31
	Power Capital Costs	$/kW Installed	451	2,855	1,883	2,310	2,028	2,028	3,089	3,089
	Energy Capital Costs	$/kWh Installed	265	372	70	123	52	52	11	2
	OPEX	% CAPEX/yr	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
2050	Cycle life	Total cycles	7,300	18,000	50,000	50,000	30,000	30,000	20,000	20,000
	Technical life	Years	20	20	35	35	35	35	35	35
	Round-Trip Efficiency	%	90	72	81	65	42	42	37	37
	Power Capital Costs	$/kW installed	307	1,686	1,804	1,950	1,056	1,056	2,024	2,024
	Energy Capital Costs	$/kWh installed	164	217	67	61	27	27	10	2
	OPEX	% CAPEX/yr	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Terminology: A-CAES, adiabatic compressed air energy storage; CST, concentrated solar thermal; eTESe, thermal energy storage (electricity input, electricity output); OPEX, operational expenditure; PHES, pumped hydro, OPEX, operational expenditure

354 Graham et al. (2022) GenCost 2021–22: Final report. CSIRO, Australia. doi:10.25919/mb22-c107

355 ARENA (2018) Comparison of dispatchable renewable electricity options. <https://arena.gov.au/assets/2018/10/Comparison-Of-Dispatchable-Renewable-Electricity-Options-ITP-et-al-for-ARENA-2018.pdf> (accessed 28 November 2022).

The values were adjusted to 2022 dollars (based on Chemical Engineering Plant Cost Index (CEPCI)) and improvements predicted by Gencost for the base year and best year, 2025 and 2050, respectively.

Power capital cost	
2018 A$/kW$_e$	2,400
2022 A$/kW$_e$	2,427
2025 (2022 A$/kW$_e$)	2,028
2050 (2022 A$/kW$_e$)	1,055

Energy capital costs

The energy capital costs (ECC) consist only of the molten salt storage system and are from the same source as the PCC. The cost is in units of MWh$_{th}$, so costs are converted to MWh$_e$ using a round trip efficiency (RTE) of 42%. The same adjustments were applied as for the PCC.

Energy capital cost	
2018 A$/kWh$_{th}$	26
2018 A$/kWh$_e$	62
2022 A$/kWh$_e$	63
2025 (2022 A$/kWh$_e$)	52
2050 (2022 A$/kWh$_e$)	27

Total capital costs

The total capital cost (TCC) is calculated as the sum of the PCC and the ECC multiplied by the hours of storage. So, assuming 8 hours of storage, the TCC for 2025 is:

TCC ($) = PCC + (ECC * 8)

= (2,028 + 52 * 8) $/kWe

= 2,444 $/kWe

Charging costs

As discussed, a heat cost is used instead of capital costs for the solar field. The costs were calculated using the System Advisory Model (SAM)[356] and discussions with experts in the area.

Heat cost 2025 (2018 A¢/kWh$_{th}$)	3.90
Heat cost 2050 (2018 A¢/kWh$_{th}$)	1.95

The charging cost is calculated on a $/kWh$_e$ basis. Using the previous assumptions and assuming an example of 8-hour storage, 230 cycles per year and a 1-MW$_e$ size, the annual charging cost (ACC) for 2025 is:

ACC ($) = Size * duration * cycles * heat cost/RTE

= 1,000 * 8 * 230 * 0.039/42%

= 170,857

A detailed Australian CSP cost model is being prepared for CSIRO by Fichtner Engineering and expected to be released in March 2023. This cost model is based on updated information from all major international and domestic CSP providers, and includes more granular Direct Normal Irradiation (DNI), system configuration and locational cost inputs. The cost model indicates that CSP costs are strongly dependent on the solar field size (economies of scale, triggered by plant and storage size) as well as the plant location (DNI potential). The cost of heat will be affected by these factors and could be lower than 3.9c/kWh$_{th}$ in higher DNI locations.

356 System Advisor Model Version 2021.12.2 (SAM 2021.12.2). National Renewable Energy Laboratory. Golden, CO. <sam.nrel.gov> (accessed 13 December 2022)

LCOS boundary for technologies analysed

Pumped hydro energy storage

PHES considers 'average' cost based on CSIRO GenCost 2021–22.[357] The LCOS boundary can be seen in Figure 42. To support analysis of PHES for a remote community, a scaling factor for small scale PHES[358] was applied to the Gencost values. The scaling factor used was 3.5 for the power capital costs,[359] with no scaling applied to the energy capital costs.

Lithium-ion batteries

The Li-ion battery is based on the lithium iron phosphate ($LiFePO_4$) battery as modelled for CSIRO GenCost 2021–22.[360] The LCOS boundary can be seen in Figure 43.

Vanadium redox flow batteries

Vanadium redox flow batteries are based on a vanadium pentoxide (V_2O_5) system, with data from CSIRO GenCost 2021–22[361] and correspondence with technology stakeholders. The LCOS boundary is similar to that for Li-ion batteries and can be seen in Figure 44.

Figure 42: PHES LCOS boundary

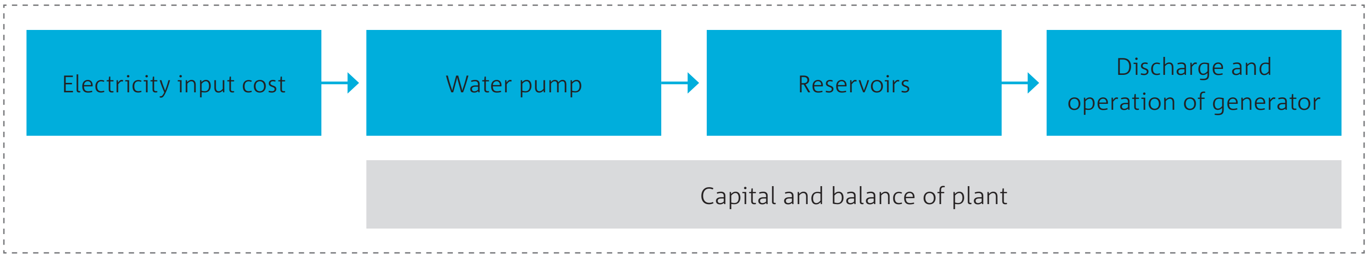


Figure 43: Li-ion LCOS boundary

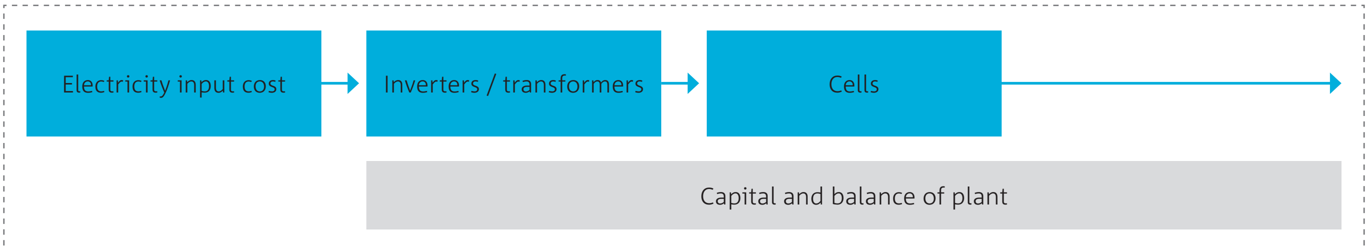
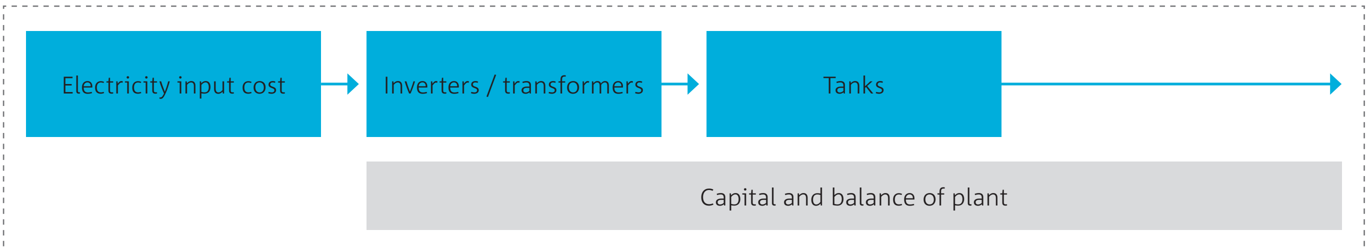


Figure 44: VRFB LCOS boundary



357 Graham et al. (2022) GenCost 2021–22: Final report. CSIRO, Australia. doi:10.25919/mb22-c107

358 International Water Power (2009) Estimating E&M powerhouse costs. <https://www.waterpowermagazine.com/features/featureestimating-em-powerhouse-costs/> (accessed 13 December 2022).

359 International Water Power (2000) Estimating E&M powerhouse costs – Table 1. <https://www.waterpowermagazine.com/features/featureestimating-em-powerhouse-costs/> (accessed 13 December 2022)

360 Graham et al. (2022) GenCost 2021–22: Final report. CSIRO, Australia. doi:10.25919/mb22-c107

361 Graham et al. (2022) GenCost 2021–22: Final report. CSIRO, Australia. doi:10.25919/mb22-c107

Compressed hydrogen gas tank and underground hydrogen storage (electrical application)

Hydrogen storage is based on the use of a polymer electrolyte membrane electrolyser with either a compressed hydrogen gas tank or underground cavern-based storage system. The power component costs are from CSIRO Gencost 2021–22,[362] whereas the energy components are from the MIT Energy Initiative's *The Future of Energy Storage*.[363] The LCOS boundary can be seen in Figure 45.

Compressed air

The A-CAES is based on proprietary purpose-built air caverns systems. The capital costs are from Hydrostor's written submission on AEMO's 2020 draft ISP.[364] The LCOS boundary can be seen in Figure 46.

Figure 45: Compressed hydrogen gas tank and underground hydrogen LCOS boundary

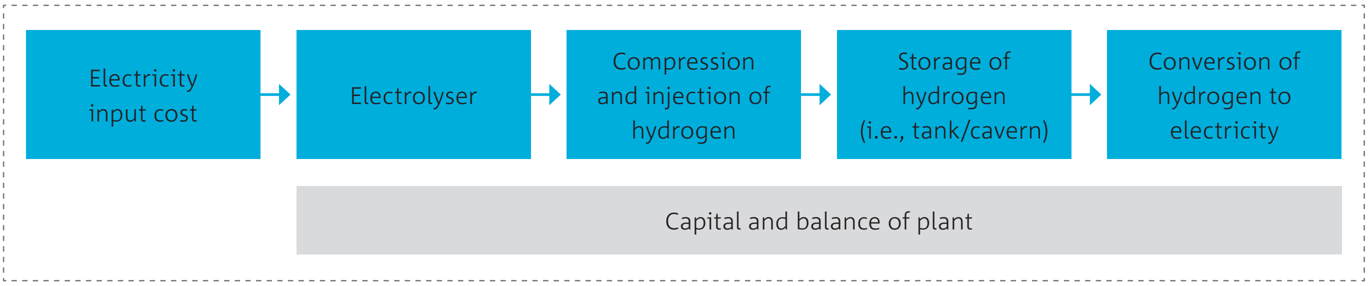
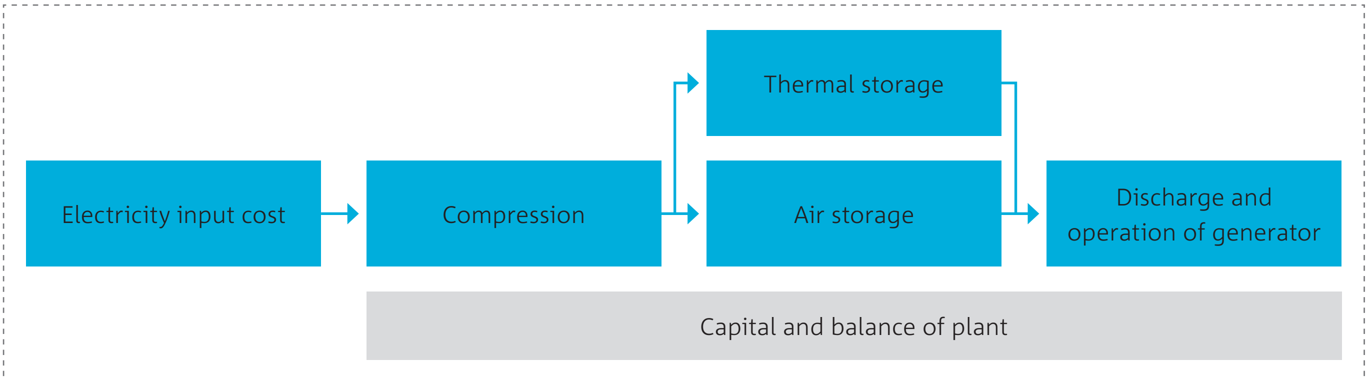


Figure 46: A-CAES LCOS boundary



362 Graham et al. (2022) GenCost 2021–22: Final report. CSIRO, Australia. doi:10.25919/mb22-c107

363 MIT Energy Initiative (2022) The future of energy storage: An interdisciplinary MIT study. Massachusetts Institute of Technology. <https://energy.mit.edu/wp-content/uploads/2022/05/The-Future-of-Energy-Storage.pdf> (accessed 24 June 2022).

364 Hydrostor (2020) Written submission on AEMO's 2020 draft ISP. <https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/draft-2020-isp/submissions/hydrostor-submission-draft-2020-isp.pdf> (accessed 11 May 2022).

Thermal energy storage systems (eTESe, electricity to thermal storage to electricity)

eTESe stores thermal energy converted from electricity via resistive heating elements. For the LCOS study, the storage medium used was molten salt. When the stored energy is required, the molten salt passes through a heat exchanger, transferring the heat to water to raise steam. This steam then passes a turbine to generate electricity. The capital costs are from ARENA's Comparison of Dispatchable Renewable Electricity Options.[365] The LCOS boundary can be seen in Figure 47.

Concentrated solar thermal storage (CST storage)

CST storage stores thermal energy captured in a CST plant. For the LCOS study, the storage medium used was molten salt. When the stored energy is required, the molten salt passes through a heat exchanger, transferring the heat to water to raise steam. This steam then passes a turbine to generate electricity. The capital costs are from ARENA's Comparison of Dispatchable Renewable Electricity Options.[366] The LCOS boundary can be seen in Figure 48. To allow comparison with other electrically charged systems, CST storage uses a heat input price (see model assumptions) based on a levelised cost of heat.

Figure 47: eTESe LCOS boundary

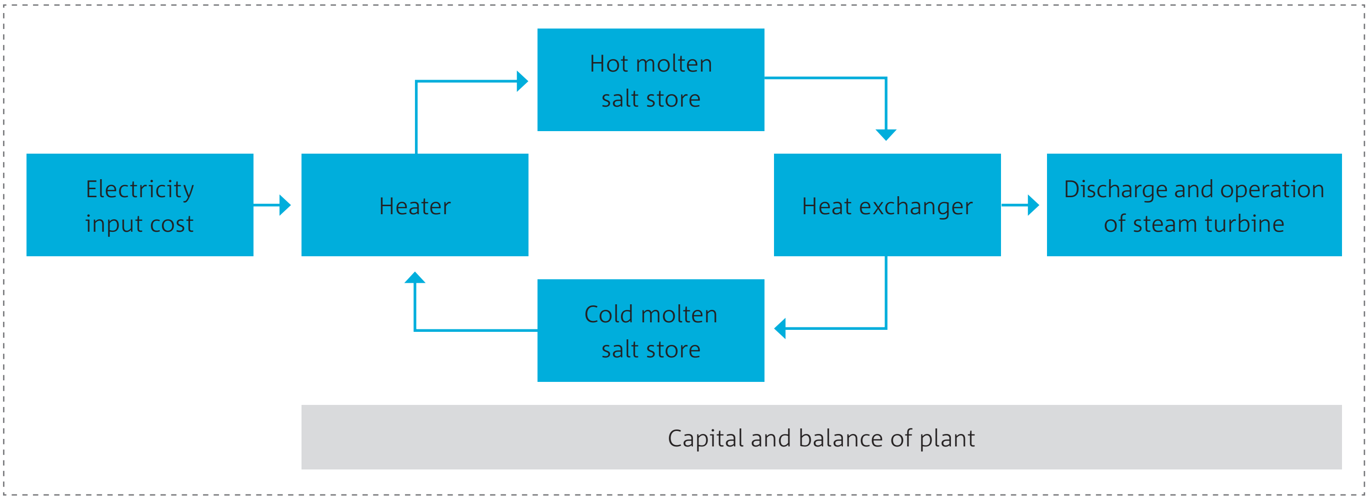
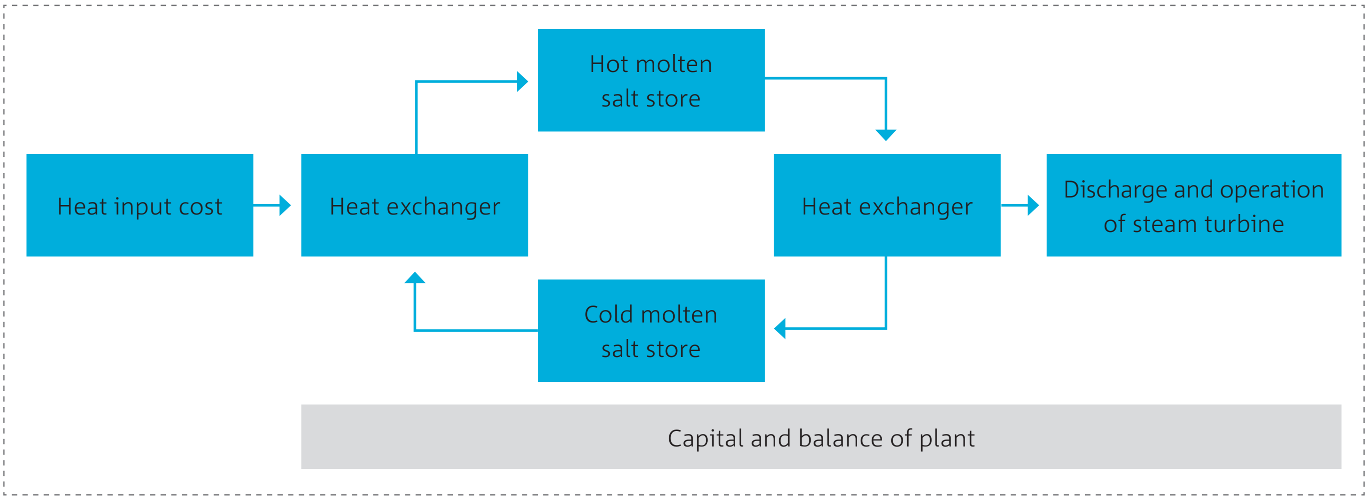


Figure 48: CST storage LCOS boundary



365 ARENA (2018) Comparison of dispatchable renewable electricity options. <https://arena.gov.au/assets/2018/10/Comparison-Of-Dispatchable-Renewable-Electricity-Options-ITP-et-al-for-ARENA-2018.pdf> (accessed 28 November 2022).

366 ARENA (2018) Comparison of dispatchable renewable electricity options. <https://arena.gov.au/assets/2018/10/Comparison-Of-Dispatchable-Renewable-Electricity-Options-ITP-et-al-for-ARENA-2018.pdf> (accessed 28 November 2022).

Appendix D: Sector-specific case study approach

Four quantitative case studies were developed to help support the qualitative sector analysis. The first two case studies are focused on understanding the long-duration storage requirement and technology options in remote grids, and the last two are focused on exploring the scale of storage that may be required in alumina refining and hydrogen export. These case studies were intentionally designed to be high level given the site- and region-specific nature of storage decision making and to help stakeholders understand options.

Remote grids: mining and remote communities

Full electrical decarbonisation of a remote off-grid site is particularly difficult due to economic, space and technical considerations. These remote grids often have no or limited opportunities to supplement onsite generation, which means onsite generation needs to meet all electricity needs. There may be long periods of wind and solar drought, and energy storage would need to be large enough to meet the load. The onsite energy storage needs to not only discharge, but also to charge, which is going to require 'excess' renewable energy on top of the renewable energy supplying the load directly. This can result in an even larger energy storage requirement if charging opportunities are limited. Currently, off-grid areas are mainly powered by diesel and gas (if there is a gas pipeline and the load is sufficiently large to warrant the investment).

Methodology

The HOMER modelling package was used to better understand storage requirements using real site data. HOMER has been used previously by CSIRO to examine the techno-economic feasibility of introducing renewable energy (PV and batteries) into various government and industry sites. HOMER performs the optimisation, but it relies on the user's data assumptions, such as electricity demand, capital and operating costs, technology performance assumptions and fuel cost (if relevant).

Although the HOMER modelling package can provide techno-economic optimisation (i.e. providing an optimised technology answer for the given site), for the purposes of this report HOMER was used to understand longer-term energy storage needs. Specifically, HOMER was used to identify the storage durations and annual cycles that were being met through the use of diesel generators. These results were then used as an input into LCOS analysis (see Appendix C) to explore storage technology options that may fill these gaps.

Overarching HOMER model assumptions

Default inbuilt HOMER solar, wind and temperature data was used in the modelling.

Systems were modelled over a 20-year life, with replacement costs and salvage costs included at end of life.

Remote mining case study assumptions

The remote mining case study considered an off-grid mining operation shifting its electrical load from being provided via diesel power generation to a high penetration of renewables (solar and wind).

Site data was provided for a mine located in remote north-western WA that has a peak load of 47.7 MW, an average load of 44.46 MW and average daily energy usage of 1,067 MWh per day. Day-to-day variability in the load is 19.3%.

Remote community case study assumptions

Two remote community case studies have been modelled, with the first community assumed to be located in a coastal location in northern Queensland with good wind resources and the second community located in the middle of the Northern Territory with good solar resources. Ergon Energy Network (2022) provided total diesel generation data in half-hourly intervals from 2013 to 2018 for a remote Queensland community. Year 2017 data was used because this was the most complete annual dataset. There were some gaps in the data that were filled with the previous measured level.

Current generation in the remote Queensland community consists of:

- 1 Cummins QST30 + Stamford alternator with 650 kW power in total
- 3 Cummins QSK60 + Stamford alternators with 1,350 kW power from each generator.

The larger generators are used for prime power and the smaller set is a backup generator.

Annual fuel usage is 3,658,690 L on average and the annual fuel bill is A$2,500,000, which equates to 0.68 $/L. Annual operating and maintenance and miscellaneous costs are A$1,848,000.

Annual energy use is 13,371,500 kWh and peak demand is 2,000 kW.

Manufacturing

High-level techno-economic analysis was conducted to understand the $/tonne of low-pressure steam for a manufacturing operation. The calculation follows a similar LCOS approach to that shown in Appendix C and considers the use of CST storage and an eTES storage system producing a thermal output compared against the use of natural gas to produce a similar thermal output.

The costs for each system did not include any water pumps or boilers, as it was assumed that they would be similar for each technology. For the natural gas system, a carbon price was added.

Alumina refining

The alumina refining case study explores the scale of energy required to displace current natural gas use in the four refiners concentrated in south-west WA, namely in the digestion and calcination-stage processes. Although there are multiple pathways to decarbonisation, we have chosen an approach where we have determined the scale of storage required when the digestion process is electrified and the calcination-stage process uses green hydrogen.

The storage numbers identified should only be viewed as rough order of magnitude estimates.

Key assumptions:

- Production and energy consumption: Aluminium Sustainability Data Tables 2000 to 2021[367] and Australian Alumina[368]
  - Alumina production: ~14 Mt/year
  - Total consumption of energy: ~150 PJ/year (~36 TWh)
  - Specific energy consumption: 10.2 GJ/t alumina (excluding purchased electricity)
  - Current natural gas consumption: ~70% of energy from natural gas is used for digestion and 30% is used for calcination. Note that in a real site, ~10% of consumption is electricity for various uses across the site
- Efficiency assumptions:
  - Natural gas boiler efficiency: 83%
  - Electric boiler efficiency: 95%
  - Efficiency loss for hydrogen/electrical calcination: 95%
- Electrification pathway assumptions:
  - The storage calculation used the results from 2050 demand modelling for WA under a flat load scenario (see Appendix B). Under this scenario, the predicted energy mix was 75% direct from VRE, with the remaining 25% requiring a storage mix of varying durations.
  - Hydrogen pathway assumptions:
  - Electrolyser efficiency: 44 kWh/kg (for 2050)

Table 18: Low-pressure steam assumptions for manufacturing case

CYCLES	DURATION	INLET TEMPERATURE	INLET PRESSURE	OUTLET TEMPERATURE	OUTLET PRESSURE	NG EFFICIENCY
	hrs	°C	bar	°C	bar	%
365	12	35	2	250	8	85.0

Note: Natural gas (NG) efficiency refers to the efficiency of burning natural gas for the application.

367 Australian Aluminium Council Ltd (n.d) Sustainability. <https://aluminium.org.au/sustainability/> (accessed 5 December 2022)
368 Australian Aluminium Council Ltd (n.d) Australian Alumina. <https://aluminium.org.au/australian-alumina/) (accessed 5 December 2022)

Hydrogen export

To help understand the potential scale of storage required for export, the roles of storage and buffering have been explored for the final stages of a liquid hydrogen export value chain, recognising that there are many ways that an export value chain could be configured and optimised.

The analysis considered storage requirements related to both small and large hydrogen export ships, with an assumed round trip time of 14 days. The quantity of hydrogen to be stored is slightly larger than what is exported due to assumptions of loading loss and the use of standard tank sizes. Using the ship size assumptions, the storage analysis considered two elements:

- the storage of gaseous hydrogen required for input to liquefaction (per day, as hydrogen is stored and removed for liquefaction)
- the buffering of liquid hydrogen required at port for loading.

Shipping and loading assumptions:

- Capacity: (Gaseous equivalent):[369]
- Small hydrogen export ship: 50,000 m^3
- Large hydrogen export ship: 160,000 m^3
- Round trip time: 14 days (i.e. by the end of a 14-day period, the ship returns to port to be loaded with liquid hydrogen)
- Loading loss: 0.5%

Liquefaction facility assumptions: CSIRO National Hydrogen Roadmap[370]

369 Small hydrogen export ship is based on a mid-sized 50,000m^3 refrigerated ammonia / LPG ship; Large hydrogen export ship based on Kawasaki (2022) Kawasaki Kawasaki Obtains AIP for Large, 160,000m^3 Liquefied Hydrogen Carrier. <https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20220422_3378> (accessed 5 December 2022).

370 Bruce S, Temminghoff M, Hayward J, Schmidt E, Munnings C, Palfreyman D, Hartley P (2018) National hydrogen roadmap. CSIRO, Australia.

Appendix E: Technology scans

This section contains technology scans for 15 energy storage technologies that were prioritised based on technical maturity and stakeholder feedback. For simplicity, these technologies have been sorted into four distinct categories:

- electrochemical
- chemical
- mechanical
- thermal.

However, in reality, the boundaries of these taxonomy brackets are blurry, with many of these technologies using principles across more than one of these areas.

Information has been collected from and informed by extensive desktop research, input from CSIRO technology experts and stakeholder engagement with a range of companies involved in the development and commercialisation of these technologies.

The technology scans should not be viewed as exhaustive. Not all information can be presented with a high level of accuracy due to the wide variations possible within each technology. In addition, the technology scans were limited by project scope, time and the availability of information. Further research could be conducted to provide more in-depth information on each technology and ensure a more comprehensive coverage of technologies across all categories.

Given the pace of change, it is hoped that these scans will eventually form part of a living document. This could be maintained and updated over time, in which case remaining gaps in knowledge could be addressed and new developments added when they emerge.

ELECTROCHEMICAL

- Electrochemical energy storage uses chemical reactions to convert and store electricity in a chemical form, which can then be reversed repeatedly and released back into the system as electricity.
- The reversible nature of electrochemical storage provides a key differentiator from chemical storage.
- Electrochemical storage systems broadly consist of conventional and flow batteries, fuel cells and capacitors.
- This roadmap considers conventional lithium ion (Li-ion) batteries, sodium ion (Na-ion) batteries, vanadium redox flow batteries (VRFB) and zinc–bromine (ZNBR) batteries.

Lithium ion batteries

Electrochemical	Chemical	Mechanical	Thermal

What is it?

Li-ion batteries are a type of rechargeable battery that function based on the transfer of lithium ions between a cathode (positive electrode) and anode (negative electrode) to store and release electricity. During discharge, lithium ions flow from the anode to the cathode through the electrolyte. Meanwhile, electrons travel around an external circuit (from cathode to anode) to balance the charge, creating an electric current.

Why is it important?

Li-ion batteries are versatile in a wide range of applications and have seen increased use in various contexts over recent years. There have been, and may continue to be, significant technological improvements and cost reductions in Li-ion batteries compared with other battery technologies given their dominance in the EV market.[371]

Benefits[374]

- High energy efficiency compared with lead–acid or flow batteries
- Greater energy storage density (energy per unit volume) than lead–acid or high-temperature batteries
- Low battery self-discharge rate (around 1.5–2% per month)[375]

	RESEARCH AND DEVELOPMENT							DEMONSTRATION						DEPLOYMENT				
TRL[372]	1	2	3	4	5	6	7	8	9									
CRI[373]		1							2		3		4		5		6	

371 World Energy Council (2020) Five steps to energy storage. London. <https://www.worldenergy.org/assets/downloads/Five_steps_to_energy_storage_v301.pdf> (accessed 8 November 2022).

372 Technical and commercial maturity levels represent multiple battery chemistries, including lithium metal polymer, lithium nickel manganese cobalt oxide and lithium iron phosphate batteries: Godfrey B, Dowling R, Forsyth M, Grafton R, Wyld I (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne; Cavanagh K, Ward J K, Behrens S, Bhatt AI, Ratnam EL, Oliver E, Hayward J (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

373 Li-ion batteries in scope are generally at CRI 5–6, but grid-scale use over 4 hours is at CRI 4. For example, Fluences' 5 hour battery (112 MW/560 MWh) development in Chile: Fluence (2020) Energy storage's next evolution is unfolding in Chile. <https://blog.fluenceenergy.com/energy-storage-next-evolution-in-chile-andes-solar>

374 Patonia A, Poudineh R (2020) Ammonia as a storage solution for future decarbonised energy systems. Oxford Institute for Energy Studies. <https://www.oxfordenergy.org/publications/ammonia-as-a-storage-solution-for-future-decarbonized-energy-systems/> (accessed 8 November 2022).

375 Clean Energy Institute (2022) Lithium-ion battery. University of Washington. <https://www.cei.washington.edu/education/science-of-solar/battery-technology/> (accessed 8 September 2022).

Limitations[376]

- Limited economies of scale possible at a system level, so minimal cost savings for large-scale systems
- Currently low options and rates of recycling for battery materials
- Battery components (metal oxide electrodes) can decompose at higher temperatures
- Heavy metals such as cobalt are used in some battery chemistries

Deployment considerations[377]

- Construction time: 8–20 weeks[378]
- Typical lifetime: 8–15 years[379]
- Maximum storage duration: Up to 8 hours[380]
- External utilities: Air conditioning may be required to prolong cell life
- Operating temperature: 0–45°C[381]
- Geographical considerations: Performance can be affected by high temperatures expected in warmer parts of Australia and will require cooling, which can affect costs
- Safety/risk management: Can be reactive and flammable, requiring complex battery management systems to avoid overcharging and over-discharging
- Environmental and social considerations: Concerns relating to the mining of lithium and other critical minerals given significant water use during extraction, land and water contamination and emissions[382] and some cases of unethical working conditions for miners[383]
- Commercial and demonstration projects in Australia: Several projects are underway in Australia, including the joint Tesla and Neoen Victorian Big Battery project (300 MW) installed outside of Geelong, Victoria, and the Hornsdale battery storage system (100 MW) in Jamestown, South Australia (SA)[384]

376 Patonia A, Poudineh R (2020) Ammonia as a storage solution for future decarbonised energy systems. Oxford Institute for Energy Studies. <https://www.oxfordenergy.org/publications/ammonia-as-a-storage-solution-for-future-decarbonized-energy-systems/> (accessed 8 November 2022).

377 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

378 For a 100-MW/100- to 800-MWh system, depending on the battery energy storage system arrangement: Aurecon (2020) 2020 Costs and technical parameter review. Aurecon, Brisbane.

379 'Lifetime' is equivalent to 500–6,000 cycles: Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

380 Storage duration ranges from 1 min to 8 hours for grid-scale use: AECOM (2015) Energy storage study: A storage market review and recommendations for funding and knowledge sharing priorities. <https://arena.gov.au/assets/2015/07/AECOM-Energy-Storage-Study.pdf> (accessed 24 October 2022).

381 Figure indicative of charging temperature range. The discharging range is broader, at 20–60°C: Ma S, Jiang M, Tao P, Song C, Wu J, Wang J, Deng T, Shang W (2018) Temperature effect and thermal impact in lithium-ion batteries: A review. Progress in Natural Science: Materials International 28, 653–666.

382 Yudhistira R, Khatiwada D, Snachex F (2022) A comparative life cycle assessment of lithium-ion and lead-acid batteries for grid energy storage. Journal of Cleaner Production 358, 131999.

383 Calvão F, Mcdonald CEA, Bolay M (2021) Cobalt mining and the corporate outsourcing of responsibility in the Democratic Republic of Congo. The Extractive Industries and Society 8, 100884.

384 Tagabe PM (2022) Australia's big batteries: New storage to match the rise of renewables. Utility Magazine. <https://utilitymagazine.com.au/australias-big-batteries-new-storage-to-match-the-rise-of-renewables/> (accessed 8 September 2022).

Vanadium redox flow batteries

Electrochemical	Chemical	Mechanical	Thermal

What is it?[385]

VRFB systems store energy using two vanadium redox couples (V^{2+}/V^{3+} in the negative and V^{4+}/V^{5+} in the positive half-cells). The chemicals are dissolved in sulfuric acid electrolyte solutions, which are pumped through the fuel cell stack, while ion exchange occurs across the membrane. An electrochemical reaction occurs that creates an electrical current to provide power.

Why is it important?

VRFB systems offer distinct advantages compared with other battery technologies. In addition to operational benefits (i.e. high discharge tolerance, reduced fire risk and scalable storage capacity), VRFBs are considered one of the most technically advanced flow battery species.[386] The scalable nature of this technology offers long-term solutions for off-grid power systems, making it particularly relevant for high-capacity, utility scale energy storage, and fulfilling energy access needs in remote and rural areas.[387]

Benefits[390]

- Strong discharge tolerance; VRFB systems can be discharged for more than 10,000 cycles over 20 years without being damaged or degrading the storage capacity (as opposed to other battery types, which are degraded upon discharge)
- Safer than Li-ion battery systems, largely because VRFB systems are water based and therefore non-flammable (this reduces the fire risk, particularly in utility scale battery systems)
- Power output can be controlled by varying the flow of the electrolyte solution
- Systems are scalable, because modular electrolyte containers can be added or removed during system design
- The vanadium electrolyte can be recycled to recover high-purity vanadium. This can be used to make VRFB electrolyte, enabling circularity and business models such as electrolyte leasing.[391] The recovered vanadium can also be used in other industries, such as steelmaking

	RESEARCH AND DEVELOPMENT						DEMONSTRATION						DEPLOYMENT					
TRL[388]	1	2	3	4	5	6	7	8	9									
CRI[389]		1							2		3		4		5		6	

385 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

386 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia; Abdin Z, Khalilpour K (2019) Chapter 4: Single and polystorage technologies for renewable-based hybrid energy systems. In Polygeneration with Polystorage for Chemical and Energy Hubs. (Ed. K Khalilpour) 77–131. Academic Publishing.

387 QEM (n.d.) Vanadium redox flow batteries – how they work. <https://www.qldem.com.au/vanadium-redox-flow-batteries-vrfbs/> (accessed 6 May 2022).

388 Chmielewski A, Kupecki J, Szabłowski Ł, Fijałkowski K, Zawieska J, Bogdziński K, Kulik O, Adamczewski T (2020) Currently available and future methods of energy storage. WWF Poland. <https://wwfint.awsassets.panda.org/downloads/wwf_poland___available_and_future_methods_of_energy_storage.pdf> (accessed 8 November 2022).

389 Commercial trials and scale up are underway; however, VRFB have faced challenges in driving mass commercialisation. Some governments are addressing this through policy and market mechanisms (e.g. the US): Rickey T (2022) Advanced grid storage technology available for commercial license. [News release] PNNL. <https://www.pnnl.gov/news-media/advanced-grid-storage-technology-available-commercial-license> (accessed 8 November 2022).

390 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

391 VSUN energy (2022) Frequently asked questions. <https://vsunenergy.com.au/faqs/> (accessed 8 November 2022).

Invinity Energy Systems (2022) Vanadium electrolyte rental/a new option for storage projects. <https://invinity.com/vanadium-electrolyte-rental/> (accessed 8 November 2022).

Bushveld Minerals (n.d.) Bushveld Energy. <https://www.bushveldminerals.com/bushveld-energy-3/> (accessed 8 November 2022).

CellCube (2022) Comparison of technologies. <https://www.cellcube.com/comparison-of-technologies/> (accessed 8 November 2022).

Limitations[392]

- Potential environmental risks if vanadium (which has low toxicity) leaks from the battery system
- High battery voltage and chemicals can place stress on cell electrodes, membranes and components of the battery cell, which may reduce operation longevity
- VRFB systems have a lower energy density than other battery technologies, such as lead–acid and Li-ion technologies
- High manufacturing and installation costs, particularly because expensive ion-exchange membranes are required to increase cross-membrane efficiency
- The technology requires connection to the grid or an external power source (electricity is required to operate the pumps); however, the electrolyte solution can be repurposed

Deployment considerations[393]

- Construction time: 1–1.5 years; time frames vary by project site and deployment size[394]
- Typical lifetime: 10–20 years[395]
- Maximum storage duration: Typically deployed for approximately 10 hours;[396] however, duration depends on the number and size of the electrolyte tanks
- External utilities: Electricity source
- Operating temperature: From –15°C to 50°C
- Geographical considerations: Land requirements for commercial systems are highly variable depending on system size, which can be reduced by stacking the modular units. Footprint requirements of commercial systems have been reported[397] to range from 185 to 3,537 m^2
- Safety/risk management: In general, VRFBs are considered to have a low risk of external shorting and leakage, and no risk of fire under typical stationary applications, because the electrolyte is non-flammable. If shorting occurs, current battery management systems are deemed adequate to prevent unsafe conditions[398]
- Environmental and social considerations: The electrolyte component can be recycled to extract high-purity vanadium; however, the production of electrolyte has significant water, emissions and waste impacts[399]
- Commercial and demonstration projects in Australia: Past demonstration projects include the Ausgrid Smart Grids Smart Cities project and a 200-kW output leveller on King Island. Yadlamalka Energy has been awarded A$5.69 million in Australian Renewable Energy Agency (ARENA) funding for their co-located vanadium flow battery storage and solar project in SA[400]

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392 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

393 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

394 Figure based on Sumitomo's largest vanadium flow battery project deployed in Hokkaido, Japan, of 17 MW/51 MWh, constructed from July 2020 to 1 April 2022: Sumitomo Electric Industries (2022) Sumitomo electric awarded for redox flow battery systems from Hokkaido electric power network. [Press release] <https://global-sei.com/company/press/2020/08/prs078.html> (accessed 8 November 2022).

Sumimoto Electric (2022) Redox Flow Battery. Brochure https://sumitomoelectric.com/sites/default/files/2022-08/download_documents/2022_%E3%83%AC%E3%83%89%E3%83%83%E3%82%AF%E3%82%B9%E3%83%95%E3%83%AD%E3%83%BC%E9%9B%BB%E6%B1%A0%EF%BC%88A4%EF%BC%89.pdf (accessed 24 November 2022)Schmidt et al. (2019) Projecting the future levelized cost of electricity storage technologies. Joule 3, 81–100.

395 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

396 Schmidt et al. (2019) Projecting the future levelized cost of electricity storage technologies. Joule 3, 81–100.

397 Footprint sizes ranging from 185 m2 (6 MWh) to 205m2 (10 MWh) have been reported for Largo Clean Energy VCHARGE systems (formerly VionX Energy): Vionx Energy (2017) VNX 1000 series product data. <http://vionxenergy.com/wp-content/uploads/2016/08/Vionx-Technology-Specifications.pdf> (accessed 8 November 2022); Sumitomo Electric has provided sample footprints for 3- to 60-MWh systems, ranging from 255 to 3537 m2.

398 Whitehead A, Rabbow T, Trampert M, Pokorny (2017) Critical safety features of the vanadium redox flow battery. Journal of Power Sources 351, 1–7.

399 Da Silva Lima L, Quartier M, Buchmayr A, Sanjuan-Delmás D, Laget H, Corbisier D, Mertens J, Dewulf J (2021) Lifecycle assessment of lithium-ion batteries and vanadium redox flow batteries-based renewable energy storage systems. Sustainable Energy Technologies and Assessments 46, 101286.

400 ARENA (2022) Co-located vanadium flow battery storage and solar. <https://arena.gov.au/projects/co-located-vanadium-flow-battery-storage-and-solar/> (accessed 8 November 2022).

Zinc bromine batteries

Electrochemical | Chemical | Mechanical | Thermal

What is it?

A ZNBR battery is a system that uses the electrochemical reaction between zinc metal and bromine to produce an electrical current. There are different types of ZNBR batteries, including flow- and gel-type batteries.

A ZNBR flow battery stores energy in electroactive species dissolved in liquid electrolytes, which are held in external storage tanks.[401] These electrolytes are filtered through electrochemical cells, which then convert chemical energy to electricity. The power capacity depends on the design of the electrochemical cell, whereas the energy capacity depends on the volume (and number) of storage tanks.[402]

Gel-type ZNBR batteries use an electrolyte that is in gel form (i.e. non-flow), and have a similar architecture to that of a conventional lead–acid battery, but with the operational attributes of ZNBR chemistry.[403]

Why is it important?

ZNBR batteries are a promising energy storage technology, offering two key advantages over other battery technologies. First, ZNBR are tolerant to overcharge or over-discharge and are considered safer than Li-ion batteries, making them an attractive and durable long-term energy storage option. Second, ZNBR are scalable because additional storage tanks can be connected to increase system storage capacity.

Benefits[406]

- Strong discharge tolerance; theoretically, ZNBR batteries can be 100% discharged every day without being damaged (as opposed to other battery types, which are often damaged upon discharge)
- Systems are scalable because energy storage capacity can be increased by connecting additional storage tanks (in the case of flow-type batteries) or additional units (in the case of gel-type batteries)
- Reduced safety risks compared with Li-ion battery technologies
- Modular and scalable systems are available[407]

	RESEARCH AND DEVELOPMENT							DEMONSTRATION						DEPLOYMENT				
TRL[404]	1	2	3	4	5	6	7	8	9									
CRI[405]		1							2		3		4		5		6	

401 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

402 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

403 Gelion (n.d.) Endure battery. <https://gelion.com/wp-content/uploads/GEL008-Endure-Battery-Technology-Brochure_V2.pdf> (accessed 8 November 2022).

404 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

405 Trade and Investment Queensland (2022) Queensland's Redflow powering storage solutions for renewables. <https://www.tiq.qld.gov.au/news/queensland%E2%80%99s-redflow-powering-storage-solutions-for-renewables> (accessed 26 October 2022).

406 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

407 Redflow (2022) Energy pod. <https://redflow.com/energy-pod> (accessed 8 November 2022).

Limitations[408]

- Lower energy than other battery types discussed in this report
- Comparatively lower RTE than other battery technologies (e.g. Li-ion)
- Complex design and manufacturing requirements increase costs and deployment time frames; however, gel-type batteries can diminish costs associated with manufacturing, capital expenditure, maintenance and the complexity of mechanical systems
- Require a power source to operate

Deployment considerations[409]

- Construction time: approximately 9 months; time frames vary by project site and deployment size[410]
- Typical lifetime: 5–10 years[411]
- Maximum storage duration: Expected to be 5 hours
- External utilities: Electricity source
- Operating temperature: 10–45°C[412]
- Geographical considerations: Although these batteries are modular and can be theoretically scaled to high capacities, large systems using flow-type batteries may require more land due to the large volume and number of electrolyte tanks
- Safety/risk management: Safety concerns are typically associated with human contact during spills or cell stack leakage. The electrolyte is not considered flammable, therefore the risk of internal fire is low. There is some risk of an external fire, which may cause bromine gas evolution. General safety precautions include providing automated extinguisher systems and ventilation systems[413]
- Environmental and social considerations: If bromine leaks from the system, it can pose toxicity and health risks.[414] However, due to low bromine concentrations in the battery, this is a slow process. Runaway chemical reactions are also unlikely
- Commercial and demonstration projects in Australia: Several systems have been deployed, including at the Darling Building (SA),[415] the 56 ZNBR Redflow batteries at remote Optus mobile bases across Australia[416] and a CSIRO site in Newcastle, NSW[417]

408 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

409 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

410 Figure is based on Redflow's largest commercial deployment at Anaergia's Rialto Bioenergy Facility in California, from announcement of sale through to completed installation of a 2-MWh energy system comprising 192 ZNBR flow batteries: Redflow (2021) Redflow signs its largest global battery sale with Anaergia to supply energy storage in California [Press release]. <https://www.anaergia.com/about-us/media-center/redflow-signs-its-largest-global-battery-sale-with-anaergia-to-supply-energy-storage-in-california/> (accessed 8 September 2022); Redflow (2021) Redflow completes 2 MWh installation in California [Press release]. <https://redflow.com/project/redflow-completes-2-mwh-installation-in-california> (accessed 8 September 2022).

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412 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

413 DNV GL (2016) Safety review of bromine-based electrolytes for energy storage applications. <http://energystorageicl.com/wp-content/uploads/2018/04/DNV-GL-Safety-Review-of-Bromine-Based-Electrolytes-for-Energy-Storage-Applications.pdf> (accessed 8 November 2022).

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415 Redflow (2022) Darling Building beats energy shortfall with Redflow. <https://redflow.com/project/darling-case-study> (accessed 11 April 2022).

416 Redflow (2021) Federal Minister's visit unveils Redflow and Optus' resilience initiative for mobile networks. <https://redflow.com/project/federal-ministers-visit-unveils-redflow-and-optus-resiliency-initiative-for-mobile-networks> (accessed 8 November 2022).

417 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

Sodium ion batteries

Electrochemical | Chemical | Mechanical | Thermal

What is it?

The working principle of Na-ion batteries is based on the movement of sodium ions between positively and negatively charged electrodes. During charging, sodium ions are extracted from the positive electrode (cathode) and migrate through a separator and electrolyte to reach the negative electrode (anode). Meanwhile, electrons travel around an external circuit (from positive to negative electrode) to balance the charge, creating an electric current.

Why is it important?

Compared with other electrochemical storage technologies, Na-ion battery cells have wider operational temperature ranges and use cheaper, safer and more abundant materials.[418] For these reasons, these cells are well suited to applications where price and environmental concerns are key priorities. Several types of Na-ion batteries are in development, including Prussian blue analogues (PBAs), Li-ion analogues and saltwater batteries.

Benefits

- Key components are predominantly synthesised from low-cost, abundant materials with secure supply chains[420]
- Considered safer than Li-ion systems, primarily due to the use of less volatile electrolytes and oxides for the cathode[421]
- Have wider operational temperature ranges than Li-ion and lead–acid batteries, making them better suited to extreme weather conditions
- They typically operate at room temperature, but also perform at low temperatures
- They have good cycle stability, with some systems reaching up to 30,000 cycles[422]

	RESEARCH AND DEVELOPMENT							DEMONSTRATION						DEPLOYMENT				
TRL[419]	1	2	3	4	5	6	7	8	9									
CRI		1							2		3		4		5		6	

418 Goikolea E, Palomares V, Wang S, Larramendi I, Guo X, Wang G, Rojo T (2020) Na-ion batteries – approaching old and new challenges. Advanced Energy Materials 10, 2002055.

419 Goikolea et al. (2020) Na-ion batteries – approaching old and new challenges. Advanced Energy Materials 10, 2002055.

420 Karabelli D, Singh S, Kiemel S, Koller J, Konarov A, Stubhan F, Miehe R, Weeber M, Bakenov Z, Birke KP (2020) Sodium-based batteries: In search of the best compromise between sustainability and maximization of electric performance. Frontiers in Energy Research. doi:10.3389/fenrg.2020.605129

421 Spoerke E, Gross M, Small L, Percival S (2020) Sodium-based battery technologies. In U.S. DOE Energy Storage Handbook. <https://www.sandia.gov/ess/publications/doe-oe-resources/eshb> (accessed 20 May 2022).

422 Abbas Q, Mirzaeian M, Hunt M (2022) Materials for sodium-ion batteries. Encyclopedia of Smart Materials, 2,106-114 < https://doi.org/10.1016/B978-0-12-803581-8.12115-0>.

Limitations

- Lower energy density than Li-ion batteries (but higher energy density than lead–acid batteries)[423]
- Are heavier and bulkier than Li-ion alternatives
- Although sodium is significantly cheaper than materials used in other battery systems, currently low TRLs and high separator and electrolyte costs make this technology more expensive to manufacture[424]

Deployment considerations

- Construction time: Insufficient data
- Typical lifetime: Laboratory tests and commercial proponents have shown potential for Na-ion batteries to achieve long lifetimes ranging from 15,000 to 50,000 cycles[425]
- Maximum storage duration: Insufficient data
- Inputs/outputs: Electricity
- External utilities: None
- Operating temperature: Typically, from –30°C to 60°C, but wider temperature systems are under investigation (from –70°C to 100°C)[426]
- Geographical considerations: Insufficient data
- Safety/risk management: Electrolytes may be flammable.[427] Unlike Li-ion batteries, Na-ion batteries can be discharged to 0 V, which can minimise potential hazards during storage and transportation[428]
- Environmental and social considerations: Lower supply chain criticality, material intensity and environmental health impacts (vs Li-ion batteries)[429]
- Commercial and demonstration projects in Australia: The Smart Sodium Storage Solution (S4) Project in New South Wales (NSW) led by the University of Wollongong, announced in 2018[430]

423 Goikolea et al. (2020) Na-ion batteries – approaching old and new challenges. Advanced Energy Materials 10, 2002055.

424 Karabelli et al. (2020) Sodium-based batteries: In search of the best compromise between sustainability and maximization of electric performance. Frontiers in Energy Research. doi:10.3389/fenrg.2020.605129

425 Wang Y, Hou B, Ning Q, Pang W, Wang J, Lu C, Wu X (2018) An ultralong lifespan and low-temperature workable sodium-ion full battery for stationary energy storage. Advanced Energy Materials 8, 1703252; Natron Energy (2022) Introducing BlueTray® 4000. <https://natron.energy/product/> (accessed 8 November 2022).

426 The range –30°C to 60°C relates to traditional Faradion Na-ion batteries: Rudola A, Sayers R, Barker J (2021) 8. Industrial targets and techno-economic analysis. In 2021 Roadmap for Sodium-Ion batteries. Journal of Physics: Energy 3, 031503. <https://iopscience.iop.org/article/10.1088/2515-7655/ac01ef#jpenergyac01efs8> (accessed 28 November 2022); Li Z, Zhang Y, Zhang J, Cao Y, Chen J, Liu H, Wang Y (2022) Sodium-ion battery with a wide operation-temperature range from –70 to 100°C. Angewandte Chemie International Edition 61, e202116930.

427 Durmus Y, Zhang H, Baakes F, Desmaizieres, Hayun H, Yang L, Kolek M, Kupers V, Janek J, Mandler D, Passerini S, Ein-Eli Y (2020) Side by side battery technologies with lithium-ion based batteries. Advanced Energy Materials 10, 2000089.

428 Rudola A, Rennie A, Heap R, Meysami S, Lowbridge A, Mazzali F, Sayers R, Wright C, Barker J (2021) Commercialisation of high energy density sodium-ion batteries: Faradion's journey and outlook. Journal of Materials Chemistry 9, 8279–8302.

429 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

430 Smart Sodium Storage System Project (2022) The smart sodium storage system project. <http://s4.isem.uow.edu.au/> (accessed 24 June 2022).

MECHANICAL

- Mechanical energy storage uses gravity, acceleration or compression to store potential or kinetic energy, which can then be used to drive a turbine or generator and produce electricity when needed.
- This roadmap considers PHES, A-CAES and gravity storage.

Pumped hydro energy storage

Electrochemical	Chemical	Mechanical	Thermal

What is it?

PHES uses two vertically separated reservoirs to store gravitational potential energy. When low-cost or excess electricity is available, energy is stored by pumping water from a lower to a higher elevated reservoir. Once this energy is required, water is released back into the lower reservoir, driving system turbines to generate electricity.[431]

Why is it important?

PHES is a mature and well-established storage technology used for large-scale energy storage and management. PHES has a low technology risk (TRL 9) and over 9,000 GWh of installed capacity worldwide, accounting for over 95% of energy storage installed globally.[432] Until recently, PHES was the only commercially proven storage technology currently capable of storing multiple GWh of energy, because GW-scale battery storage has only recently become commercially available.[433]

	RESEARCH AND DEVELOPMENT						DEMONSTRATION						DEPLOYMENT					
TRL[434]	1	2	3	4	5	6	7	8	9									
CRI[435]		1							2		3		4		5		6	

431 AECOM (2015) Energy storage study: A storage market review and recommendations for funding and knowledge sharing priorities. <https://arena.gov.au/assets/2015/07/AECOM-Energy-Storage-Study.pdf> (accessed 24 October 2022).

432 World Energy Council (2020) Five steps to energy storage: Innovation insights brief. <https://www.worldenergy.org/assets/downloads/Five_steps_to_energy_storage_v301.pdf> (accessed 8 November 2022).

433 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

Farquhar L, Bryce B (2021) Plans unveiled for world's biggest battery in the Hunter Valley. ABC News. < https://www.abc.net.au/news/2021-02-05/plans-unveiled-for-worlds-biggest-battery-in-hunter-valley/13124814> (accessed 8 November 2022).

434 Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

435 Internal source.

Benefits[436]

- Capacity for both large-scale (multiple GWh) and long-duration (12–24 hours) energy storage
- Currently the most cost-effective centralised large-scale storage technology for long-duration applications

Limitations[437]

- Geographical and environmental site requirements can limit the number of sites available for PHES
- Projects are often large scale, requiring many years to obtain capital, build approvals and complete installation
- The transmission distance to an existing grid may be longer than other storage options due to the need to locate PHES projects at a site with suitable geographical features

Deployment considerations[438]

- Construction times: 3–7 years,[439] highly dependent on site characteristics, project scales and the type of PHES
- Typical lifetime: Decades (up to 60 years)[440]
- Maximum storage duration: Typically deployed for 12–24 hours. However, can provide energy for short- and medium-duration needs. Some projects can offer multiday storage.[441] Small systems are under investigation.
- Inputs/outputs: Water, electricity
- External utilities: Energy source (to fill the reservoir), water source, transmission lines and switchyard (if connected to the grid)
- Operating temperature: Ambient[442]
- Geographical considerations: Requires specific geological structures for storage; however, potential PHES sites in Australia have been identified by researchers at the Australian National University[443]
- Safety/risk management: Dam failure may threaten the safety of workers and affect downstream communities and the environment. Safety measurements include installing flood protection systems (i.e. drainage pumps, automatic closure of intake gates and valves), adequate fire and smoke control and retrofitting older plants with modern safety systems
- Environmental and social considerations: Lifecycle analyses highlight natural land transformation and high mineral requirements for constructing basins as key environmental considerations for PHES systems[444]
- Commercial and demonstration projects in Australia: Multiple sites in operation, including Wivenhoe Pocket (Queensland), Snowy Mountains, Tumut River, Bendeela and Kangaroo Valley (NSW) and Great Lake (Tasmania)

436 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.
Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

437 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.
World Energy Council (2020) Five steps to energy storage: Innovation insights brief. <https://www.worldenergy.org/assets/downloads/Five_steps_to_energy_storage_v301.pdf> (accessed 8 November 2022).

438 Cavanagh K et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

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440 AECOM (2015) Energy storage study: A storage market review and recommendations for funding and knowledge sharing priorities. <https://arena.gov.au/assets/2015/07/AECOM-Energy-Storage-Study.pdf> (accessed 24 October 2022).

441 Internal source. Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

442 Cavanagh K et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

443 Stocks M, Stocks R, Lu B, Cheng C, Blakers A (2021) Global atlas of closed-loop pumped hydro energy storage. Joule 5, 270–284; RE100 Group (n.d.) Global pumped hydro energy storage atlas. Australian National University, Canberra. <https://re100.eng.anu.edu.au/globalatlas/#references> (accessed 4 October 2022).

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Compressed air energy storage system: Adiabatic

Electrochemical	Chemical	Mechanical	Thermal

What is it?

A-CAES stores energy in the form of compressed air and heat. There are three basic processes in A-CAES:

1. Air compression: Excess or low-cost electricity drives air compressors, converting the electrical energy into stored potential energy.
2. Storage: Pressurised air is stored in vessels, pipes, underground reservoirs or caverns. During the compression process, the heat of compression is transferred and stored in a thermal energy storage (TES) system.
3. Power generation: When the compressed air is released, it expands, driving a turbine generator to produce power. The stored heat is used to aid the expansion process and support system efficiency.

Why is it important?

Although diabatic compressed air energy storage (D-CAES) systems are considered mature with commercial systems available, A-CAES systems are still under demonstration. A-CAES systems are flexible, with several permutations that can enhance efficiency, allowing users to choose a system that best suits their needs.[445] Given adiabatic systems recycle heat, ambient A-CAES systems are also more efficient than conventional D-CAES systems. These features, alongside high capacity and power ratings, ensure that A-CAES systems can provide significant storage at a relatively low cost.[446]

Benefits[449]

- Greater RTE than D-CAES systems (70% efficiency for A-CAES vs 50–60% for D-CAES)
- A-CAES systems are less capital intensive than many other storage technologies because existing infrastructure, such as unused mine caverns and depleted gas wells, can be repurposed
- The adiabatic thermal storage system does not require the burning of fossil fuels and is an emission-free technology
- A-CAES systems can be configured to provide ancillary services, such as frequency response and load balancing

	RESEARCH AND DEVELOPMENT								DEMONSTRATION						DEPLOYMENT			
TRL[447]	1	2	3	4	5	6	7	8	9									
CRI[448]		1							2		3		4		5		6	

445 Clennell B, Czapla J, Green C, Wilkins A, Sheldon H, Cousins A, Lacey J, White C, Ahmed S, Irons M (2022) Underground energy storage. CSIRO, Australia. [Unpublished]

446 Tola V, Meloni V, Spadaccini F, Cau G (2017) Performance assessment of adiabatic compressed air energy storage (ACAES) power plants integrated with packed-bed thermocline storage systems. Energy Conversion and Management 151, 343–356.

447 Alacaes (2022) Pilot plant. <https://alacaes.com/technology/pilot-plant/> (accessed 10 June 2022).

448 Hydrostor (n.d.) Goderich energy storage facility. <https://www.hydrostor.ca/goderich-a-caes-facility/> (accessed 12 October 2022).

449 Clennell et al. (2022) Underground energy storage. CSIRO, Australia. [Unpublished]

Limitations[450]

- Underground storage can be limited to regions with suitable geological formations
- Lower RTE than other energy storage technologies (i.e. batteries and PHES)

Deployment considerations[451]

- Construction time: 2.5–3.5 years[452]
- Typical lifetime: ≥50 years[453]
- Maximum storage duration: 6–24 hours;[454] however, longer-duration systems may be demonstrated in the future
- Inputs/outputs: It is estimated around 1.4–1.5 kWh electrical energy is required to return 1 kWh to the grid. Possible permutations for external heat sources include solar thermal, geothermal, green hydrogen and waste heat[455]
- External utilities: Requires a compressor, storage, turbine, thermal energy storage and generator
- Operating temperature: Includes low (<200°C), medium (200–400°C) and high (>400°C) operating temperature ranges[456]
- Geographical considerations: Some deployments can require impermeable underground structures, such as salt caverns, mine shafts or porous reservoirs. Above-ground systems have no geological constraints
- Safety/risk management: Maximum air pressure should be limited to the parameters of the system structure. Introducing oxygenated air in subsurface environments could impact bacterial growth, residual hydrocarbons, geochemical reactions and nearby water resources
- Environmental and social considerations: Low environmental impacts compared with conventional CAES systems because no fossil fuels are burnt; however, the use of underground caverns should be supported by community engagement activities
- Commercial and demonstration projects in Australia: Hydrostor has been selected by Transgrid as the preferred provider for a 200-MW storage facility in Broken Hill, NSW.[457] The construction of this 200-MW A-CAES plant at the former Broken Hill mine is planned to commence in early to mid-2023[458]

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450 Clennell et al. (2022) Underground energy storage. CSIRO, Australia. [Unpublished]

451 Budt M, Wolf D, Span R, Yan J (2016) A review on compressed air energy storage: Basic principles, past milestones and recent developments. Applied energy 170, 250–268; Clennell et al. (2022) Underground energy storage. CSIRO, Australia. [Unpublished]

452 Figure indicates construction times for a 250-MW system: Hydrostor (2020) Written submission on AEMO's 2020 draft ISP. <https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/draft-2020-isp/submissions/hydrostor-submission-draft-2020-isp.pdf> (accessed 11 May 2022).

453 World Energy Council (2020) Five steps to energy storage: Innovation insights brief<https://www.worldenergy.org/assets/downloads/Five_steps_to_energy_storage_v301.pdf> (accessed 8 November 2022).

454 McKinsey & Company (2021) Net-zero power: Long duration energy storage for a renewable grid. <https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability/our%20insights/net%20zero%20power%20long%20duration%20energy%20storage%20for%20a%20renewable%20grid/net-zero-power-long-duration-energy-storage-for-a-renewable-grid.pdf> (accessed 8 November 2022).

455 Clennell et al. (2022) Underground energy storage. CSIRO, Australia. [Unpublished]

456 Operating temperatures vary according to system engineering and the TES in use.

457 Hydrostor (2022) Hydrostor's compressed air energy storage selected as preferred option by transgrid to provide back-up electricity for Broken Hill, New South Wales. [Press release] <https://www.hydrostor.ca/hydrostors-compressed-air-energy-storage-selected-as-preferred-option-by-transgrid-to-provide-back-up-electricity-for-broken-hill-new-south-wales/> (accessed 8 November 2022).

458 Hon Chris Bowen MP (2022) $45 million for underground renewable energy storage in Broken Hill. Media releases. https://minister.dcceew.gov.au/bowen/media-releases/45-million-underground-renewable-energy-storage-broken-hill (accessed 11 December 2022); Marshall C (2022) Broken Hill's compressed-air energy storage project chosen as best back-up power supply option. <https://www.abc.net.au/news/2022-05-27/transgrid-hydrostor-broken-hill-back-up-power-option/101103082> (accessed 10 June 2022); Transgrid (2022) Preferred option for Broken Hill back up electricity supply identified. <https://www.transgrid.com.au/media-publications/news-articles/preferred-option-for-broken-hill-back-up-electricity-supply-identified> (accessed 10 June 2022).

Liquid air energy storage

Electrochemical	Chemical	Mechanical	Thermal

What is it?

LAES is based on the concept that air can be liquefied at a low temperature and ambient pressure, greatly reducing its specific volume (by approximately 700-fold). The system charges by using excess energy to compress and liquefy air at –196°C, which is then stored in unpressurised vessels. When needed, the liquid air is heated, causing it to expand as a pressurised gas, which operates a turbine to produce electricity.[459]

Why is it important?

LAES is a versatile energy storage technology that can be integrated with other TES and thermal energy sources. Moreover, LAES systems can overcome the geographical constraints that are associated with other large-scale electrical energy storage technologies.[460] For example, CAES deployed at large scales favours an underground cavern or porous reservoir for air storage, meaning that locations are limited to places with suitable geology. However, LAES only requires surface ground conditions for a site to be suitable.

Benefits[462]

- LAES systems demonstrate potential for integration with other industrial processes and systems (hybrid LAES) to recover waste cold and waste heat streams available
- LAES systems allow for the simultaneous production of electricity and cooling energy for polygeneration purposes
- LAES systems have a larger energy density than other mechanical energy storage technologies, such as PHES or CAES
- LAES does not suffer from geographical restrictions and is built using flexible, modular and well-understood components, which may prove advantageous for rapid and scalable deployment[463]

Limitations[464]

- LAES systems can have large above-ground footprint and infrastructure requirements compared with underground CAES systems
- LAES systems have a low frequency of operation (typically less than once a day)[465]
- LAES systems need complicated control systems to manage the numerous thermal energy exchange processes

	RESEARCH AND DEVELOPMENT								DEMONSTRATION					DEPLOYMENT				
TRL[461]	1	2	3	4	5	6	7	8	9									
CRI		1							2		3		4		5		6	

459 Borri E, Tafone A, Romagnoli A, Comodi G (2021) A review on liquid air energy storage: History, state of the art and recent developments. Renewable and Sustainable Energy Reviews 137, 110572.

460 Borri et al. (2021) A review on liquid air energy storage: History, state of the art and recent developments. Renewable and Sustainable Energy Reviews 137, 110572.

461 Vecchi A, Li Y, Ding Y, Mancarella P, Sciacovelli A (2021) Liquid air energy storage (LAES): A review on technology state-of-the-art, integration pathways and future perspectives. Advances in Applied Energy 3, 100047.

462 Borri et al. (2021) A review on liquid air energy storage: History, state of the art and recent developments. Renewable and Sustainable Energy Reviews 137, 110572.

463 Vecchi et al. (2021) Liquid air energy storage (LAES): A review on technology state-of-the-art, integration pathways and future perspectives. Advances in Applied Energy 3, 100047.

464 Legrand M, Rodríguez-Antón L, Martinez-Arevalo C, Gutiérrez-Martín F (2019) Integration of liquid air energy storage into the Spanish power grid. Energy 187, 115965.

465 Chmielewski et al. (2020) Currently available and future methods of energy storage. WWF Poland. <https://wwfint.awsassets.panda.org/downloads/wwf_poland___available_and_future_methods_of_energy_storage.pdf> (accessed 16 May 2022).

Deployment considerations[466]

- Construction time: Expected to be 2 years[467]
- Typical lifetime: 20–40 years[468]
- Maximum storage duration: 10–25 hours for pilot scale systems of 50–100 MW[469]
- Inputs/outputs: In standalone LAES, input/output energy streams are electricity only. In hybrid LAES, the system may interact with external processes, so inputs may include electricity, fuels or other fluids
- External utilities: General requirements include a compressor, liquefaction unit, hot and cold thermal energy storage, liquid air storage, cryogenic turbomachinery, heat exchanger and power generator
- Operating temperature: Air is liquefied and stored at –196°C
- Geographical considerations: Although there are no geological constraints, integration and collocation with nearby processes (e.g. liquefied natural gas terminals or existing electrical plants) can improve cycle efficiency by making use of waste heat recovery[470]
- Safety/risk management: Precautions are required for the handling and processing of extreme cold and hot fluids. Liquid oxygen may pose fire and explosion risks; controls include using well-insulated systems and monitoring oxygen content in liquid air
- Environmental and social considerations: Liquid air produced with renewable energy is environmentally benign. Hybrid systems that use non-renewable energy sources require CO_2 capture technologies to reduce environmental impacts
- Commercial and demonstration projects in Australia: Commercial-scale LAES options are yet to be established in Australia

466 Vecchi et al. (2021) Liquid air energy storage (LAES): A review on technology state-of-the-art, integration pathways and future perspectives. Advances in Applied Energy 3, 100047; Qi M, Park J, Lee I, Moon I (2022) Liquid air as an emerging energy vector towards carbon neutrality: A multi-scale systems perspective. Renewable and Sustainable Energy Reviews 159, 112201; Qi M, Liu Y, Landon R, Liu Y, Moon I (2021) Assessing and mitigating potential hazards of emerging grid-scale electrical energy storage systems. Process Safety and Environmental Protection 149, 994–1016.

467 Figure indicates construction time for a 50-MW/300-MWh system based on the construction schedule for Highview's CRYOBattery facility in Manchester, UK: MAN Energy Solutions (2021) MAN Energy Solutions confirms world-first LAES project. <https://www.man-es.com/company/press-releases/press-details/2021/07/14/man-energy-solutions-confirms-world-first-laes-project> (accessed 8 November 2022).

468 The typical design lifetime of an LAES plant is 30 years: Vecchi et al. (2021) Liquid air energy storage (LAES): A review on technology state-of-the-art, integration pathways and future perspectives. Advances in Applied Energy 3, 100047.

469 LDES Council (2022) Net-zero power: Long duration energy storage for a renewable grid. McKinsey & Company. <https://www.mckinsey.com/capabilities/sustainability/our-insights/net-zero-power-long-duration-energy-storage-for-a-renewable-grid> (accessed 8 November 2022).

470 Damak C, Leducq D, Hoang H, Negro D, Delahaye A (2020) Liquid air energy storage (LAES) as a large-scale storage technology for renewable energy integration – a review of investigation studies and near perspectives of LAES. International Journal of Refrigeration 110, 208–218.

Gravity energy storage: Vertical weight systems

Electrochemical	Chemical	Mechanical	Thermal

What is it?

Gravity energy storage systems use weights (i.e. concrete blocks) or pistons to store electrical energy by converting it to gravitational potential energy. There are several permutations of these systems that operate under the same principle; weights are raised vertically during the charging phase and then released during the discharging phase, which drives a generator to produce electricity.

Permutations include dry above-ground or underground systems and wet underground systems. Dry systems may operate above ground (using cranes) or below ground (using deep caverns, such as abandoned mine shafts). In a wet system, the piston is suspended in an underground water-filled shaft, with water pumped in to lift the piston. Upon discharge, the piston forces water through a pipe to drive a turbine and generate electricity.[471]

Why is it important?

Gravity energy storage systems store excess energy (using off-peak electricity or renewable energy) that can be released during peak hours in rapid, short bursts or for longer periods of up to several hours. The systems can be integrated into any high-voltage transmission grids to support grid-balancing needs on a local level. Fast response times are particularly valuable in the context of backup power markets and industrial uses.

Benefits

- Underground systems require minimal land use and can make use of decommissioned mine excavations[474]
- Some dry systems may be coupled with secondary energy storage systems. For example, by sealing an underground cavern, the space can simultaneously be used as a pressure vessel for CAES and for gravity energy storage[475]
- These systems have high cyclability (i.e. their capacity does not degrade each cycle)[476]
- Power capacity is decoupled from energy capacity, improving system scalability and suitability for high-power applications[477]
- Systems have fast response times and high output configurations[478]

	RESEARCH AND DEVELOPMENT						DEMONSTRATION					DEPLOYMENT						
TRL[472]	1	2	3	4	5	6	7	8	9									
CRI[473]		1							2		3		4		5		6	

471 Botha C, Kamper M (2019) Capability study of dry gravity energy storage. Journal of Energy Storage 23, 159–174.

472 Some pilots for more basic systems are taking place (outside of Australia), but other more novel systems are still at low TRL; Enel (2021) Wind power and energy storage converge in the name of circular innovation https://www.enelgreenpower.com/media/news/2021/07/innovation-wind-energy-storage (accessed 24 November 2022); Businesswire (2022) 2-Gigawatt Hour (2 GWh) Mandate Announced for Energy Vault's EVxTM Gravity Energy Storage Platform for Initial Zero Carbon Industrial Parks in China < https://www.businesswire.com/news/home/20220915005772/en/2-Gigawatt-Hour-2-GWh-Mandate-Announced-for-Energy-Vault> (accessed 24 November 2022)

473 Energy Vault (2022) Energy Vault, Atlas Renewable and China Tianying begin construction of first Chinese deployment of EVx™ gravity-based energy storage system. Business Wire. <https://www.businesswire.com/news/home/20220505005467/en/Energy-Vault-Atlas-Renewable-and-China-Tianying-Begin-Construction-of-First-Chinese-Deployment-of-EVx™-Gravity-Based-Energy-Storage-System> (accessed 28 November 2022); Murray C (2022) Energy Vault gets 2GWh mandate for gravity energy storage solution at industrial parks in China. Energy Storage News. <https://www.energy-storage.news/energy-vault-gets-2gwh-mandate-for-gravity-energy-storage-solution-at-industrial-parks-in-china/> (accessed 8 November 2022); Paul S (2022) Korea Zinc backs storage developer Energy Vault in green push. Australian Financial Review. <https://www.afr.com/policy/energy-and-climate/korea-zinc-backs-storage-developer-energy-vault-in-green-push-20220105-p59m42> (accessed 8 November 2022).

474 Ruoso A, Caetano N, Rocha L (2019) Storage gravitational energy for small scale industrial and residential applications. Inventions 4, 64.

475 Botha C, Kamper M (2019) Capability study of dry gravity energy storage. Journal of Energy Storage 23, 159–174.

476 Morstyn T, Chilcott M, McCulloch M (2019) Gravity energy storage with suspended weights for abandoned mine shafts. Applied Energy, 239, 201–206.

477 Morstyn et al. (2019) Gravity energy storage with suspended weights for abandoned mine shafts. Applied Energy, 239, 201–206; Botha C, Kamper M (2020) Linear electric machine-based gravity energy storage for wind farm integration. IEEE. <https://ieeexplore.ieee.org/document/9041100> (accessed 8 November 2022).

478 Botha C, Kamper M (2019) Capability study of dry gravity energy storage. Journal of Energy Storage 23, 159–174.

Limitations

- Below-ground systems may be limited by the availability of abandoned mine shafts (or limited data to estimate the number of shafts amenable to development or redesign), whereas human-formed underground systems may require significant excavation and land-reforming activities[479]
- Maximum energy storage depends on the dimensions of the shaft or tower and the maximum weight that can be used (therefore, energy storage capacity is limited) [480]
- Systems are physically large due to their low energy density;[481] this may limit the potential for above-ground systems to achieve high-capacity, long-duration storage[482]

Deployment considerations

- Deployment time frames: Expected to be 1–3.5 years; highly dependent on site characteristics and the type of gravity system used[483]
- Typical lifetime: 40–60 years[484]
- Maximum storage duration: 6–18 hours; highly dependent on system type[485]
- Inputs/outputs: Hoisting systems are typically electrically powered; water is required for wet systems
- External utilities: General infrastructure requirements include weights and a hoisting/lowering system. Dry systems require a guidance system to prevent collisions between the weight and shaft or to ensure the precise stacking of weights. Wet systems also require a pump turbine and a piping network[486]
- Operating temperature: N/A
- Geographical considerations: Underground systems may require excavation and preparation to ensure cavern parameters (i.e. depth and diameter) are suitable.[487] Despite no geological constraints, above-ground systems have footprint requirements for their facilities.
- Safety/risk management: Does not require toxic or flammable materials. There may be uncertainties regarding the safety of previously unmonitored mine shafts and newly built caverns
- Environmental and social considerations: Environmental footprint and social licence considerations are highly dependent on the materials and systems used (i.e. concrete blocks may increase the carbon footprint, whereas using renewable energy for charging may lower it).[488] Rehabilitation of decommissioned legacy mines may reuse existing infrastructure, but other underground systems will require land-disturbing activities.[489] Wet systems will need to consider water availability
- Commercial and demonstration projects in Australia: Although commercial-scale gravity energy storage options are yet to be established in Australia, several companies have expressed interest, including BHP and Korea Zinc using Energy Vault technology, and the Australian startup Green Gravity[490]

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479 Bowoto O, Emenuvwe O, Azadani M (2021) Gravitricity based on solar and gravity energy storage for residential applications. International Journal of Energy and Environmental Engineering 12, 503–516.

480 Morstyn et al. (2019) Gravity energy storage with suspended weights for abandoned mine shafts. Applied Energy 239, 201–206.

481 Botha C, Kamper M (2020) Linear electric machine-based gravity energy storage for wind farm integration. IEEE. <https://ieeexplore.ieee.org/document/9041100> (accessed 8 November 2022).

482 To achieve 10 MW power requires 1000 tonnes of mass moving vertically at 1 m/s; to store 24 MWh energy requires 8640 tonnes to be raised vertically 1 km.

483 Approximately 1 year for a dry underground system (based on Gravitricity technology). The 3.5-year approximation relates to a wet system (based on Heindl Energy technology): Schmidt O (2018) Levelised cost of storage for Gravitricity storage systems. Imperial College London Consultants and Storage Lab; Schmidt O (2018) Levelized cost of storage: Gravity storage. Imperial College London Consultants and Storage Lab. <https://heindl-energy.com/wp-content/uploads/2018/10/LCOS_GravityStorage-II-Okt-2018.pdf> (accessed 8 November 2022).

484 Based on a Heindl Energy wet gravitational storage system: Schmidt O (2018) Levelized cost of storage: Gravity storage. Imperial College London Consultants and Storage Lab. <https://heindl-energy.com/wp-content/uploads/2018/10/LCOS_GravityStorage-II-Okt-2018.pdf> (accessed 8 November 2022).

485 Energy Vault (2022) Gravity-based storage: Long duration. <https://www.energyvault.com/ldes#:~:text=Offers%20breakthrough%20storage%20capability%20ranging,%2Defficiency%20of%20over%2080%25> (accessed 8 November 2022); Heindl Energy GmbH (2022) Heindl Energy. <https://heindl-energy.com/> (accessed 8 November 2022).

486 Morstyn T, Botha C (2022) Gravitational energy storage with weights. Encyclopedia of Energy Storage 2, 64–73.

487 Franklin M, Fraenkel P, Yendell C, Apps R (2022) Gravity energy storage systems. In Storing Energy. (Ed T Letcher) 91–116. Elsevier.

488 Bowoto et al. (2021) Gravitricity based on solar and gravity energy storage for residential applications. International Journal of Energy and Environmental Engineering 12, 503–516.

489 Saigustia C, Robak S (2021) Review of potential energy storage in abandoned mines in Poland. Energie 14, 6272.

490 Paul S (2022) Korea Zinc backs storage developer Energy Vault in green push. Australian Financial Review. <https://www.afr.com/policy/energy-and-climate/korea-zinc-backs-storage-developer-energy-vault-in-green-push-20220105-p59m42> (accessed 24 June 2022); Green Gravity (2022) Home. <https://greengravity.com/> (accessed 24 June 2022).

CHEMICAL

- Chemical energy is the energy stored in the bonds and atoms of compounds (i.e. fuels and gases). This energy is released during the event of a chemical reaction, typically combustion.
- This roadmap considers hydrogen storage (compressed, underground and via metal hydrides) and ammonia.
- These low-emissions fuels will play an important role in Australia's transition, particularly in supporting industries that are difficult to electrify.

Hydrogen: Hydrogen gas tanks

Electrochemical	**Chemical**	Mechanical	Thermal

What is it?

Hydrogen gas tanks are a commercially viable, well-established energy storage method. This method involves mechanically compressing hydrogen gas and then storing it in high-pressure storage vessels (often steel or composite tanks).[491] For above-ground vessels, compressed hydrogen is usually stored at pressures under 100 bar for bulk storage; however, it can be stored a very high pressures (e.g. 700 bar) for small-scale storage, such as on board a fuel cell vehicle.[492] Storage vessels are classified into four groups according to their composition (i.e. the materials used):[493]

- Type I (metal-only cylinder)
- Type II (metal-lined hoop-wrap cylinder)
- Type III (fully wrapped composite cylinder)
- Type IV (fully wrapped composite cylinder with a plastic liner).

Why is it important?

Compressed hydrogen stored in high-pressure tanks is an enabling technology needed to facilitate hydrogen storage and distribution, providing stationary and mobile energy storage. The high energy density (e.g. 1,332 kWh/m^3 for 700 bar storage) of compressed hydrogen and low capital and operation costs ensure hydrogen can be transported and deployed cost effectively.[494] This supports the use of hydrogen in industry and in hydrogen vehicle and refuelling applications.

	RESEARCH AND DEVELOPMENT							DEMONSTRATION						DEPLOYMENT				
TRL	1	2	3	4	5	6	7	8	9									
CRI[495]		1							2		3		4		5		6	

491 CSIRO (2021) Hydrogen technology marketplace: Metal-composite pressurised vessels. <https://www.csiro.au/en/work-with-us/ip-commercialisation/hydrogen-technology-marketplace/metal-composite-pressurised-vessels> (accessed 10 May 2022).

492 Wolf E (2015) Large-scale hydrogen energy storage. In Electrochemical Energy Storage for Renewable Sources and Grid Balancing. (Eds PT Moseley, J Garghe) 129–142. Elsevier, Amsterdam.

493 Langmi H, Engelbrecht N, Modisha P, Bessarabov D (2022) Hydrogen storage in electrochemical power sources: Fundamentals, systems and applications. In Hydrogen Production by Water Electrolysis. (Eds T Smolinka, J Garche) 455–486, Elsevier,

494 Hong X, Thaore V, Karimi I, Farooq S, Wang X, Usadi A, Chapman B, Johnson R (2021) Techno-enviro-economic analyses of hydrogen supply chains with an ASEAN case study. International Journal of Hydrogen Energy 46, 32914–32928; Stetson N, McWhorter S, Ahn C (2016) Introduction to hydrogen storage. Compendium of Hydrogen Energy 2, 3–25; Reuß M, Dimos P, Léon A, Grube T, Robinius M, Stolten D (2021) Hydrogen road transport analysis in the energy system: A case study for Germany through 2050. Energies 14, 3166.

495 Maturity varies according to end use. Power applications connected to the grid are at TRL 9/CRI 2; the integration of hydrogen tanks at refuelling stations is at TRL 9/RI 4; and the storage of hydrogen gas as a chemical is at TRL 9/CRI 5-6: Harmsen N (2018) Hydrogen-fuelled power plant planned at Port Lincoln. ABC News. <https://www.abc.net.au/news/2018-02-12/hydrogen-power-plant-port-lincoln/9422022> (accessed 26 October 2022); IEA (2022) Global hydrogen review 2022. <https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf> (accessed 20 October 2022).

Benefits[496]

- Highly suitable for stationary energy storage, particularly in areas without existing energy-related infrastructure
- Higher volumetric and gravimetric energy densities than other energy storage technologies, such as Li-ion batteries

Limitations[497]

- Lower RTE for energy storage than batteries (e.g. 47% vs 70–95% respectively)[498]
- Energy storage loss depends on the storage vessel classification (i.e. the material's properties)
- An energy-intensive process is required to mechanically compress hydrogen gas
- Currently not suitable for utility scale hydrogen storage for network demand management, stabilisation and time shifting compared with other hydrogen storage methods (e.g. underground hydrogen)

Deployment considerations

- Construction time: 1 year[499]
- Typical lifetime: 10–20 years, assuming ongoing maintenance[500]
- Maximum storage duration: This will depend on vessel materials, maintenance and durability issues, such as embrittlement or leakage[501]
- Inputs/outputs: Electricity for compressors to operate
- External utilities: Compression infrastructure (e.g. diaphragm compressors)
- Operating temperature: Ambient temperature (e.g. at 100 bar, the temperature is 20°C)[502]
- Geographical considerations: Flexibly located. The footprint depends on storage capacity, vessel type and dimensions, the direction of storage (i.e. horizontal or vertical storage tank systems) and the size of the compression equipment.[503] Seamless hydrogen storage vessels commonly used in hydrogen fuel stations have inner diameters of 6.1 m and lengths ≤12 m, and can be interconnected to meet volume requirements[504]
- Safety/risk management: Hydrogen has a lower combustion point than other fuels. Sufficient ventilation is necessary to ensure any hydrogen leaks can be diluted
- Environmental and social considerations: Ongoing maintenance and monitoring are required to ensure the safety and integrity of the storage vessels
- Compressed hydrogen has been used commercially for decades in the chemicals and refinery industries (e.g. ammonia production). There are over 900 supported commercial deployments of hydrogen tanks at HRS worldwide.[505] Demonstration projects for utility scale grid support services include the Port Lincoln Hydrogen Energy Storage System commissioned in SA[506]

496 CSIRO (2021) Hydrogen technology marketplace: Metal-composite pressurised vessels. <https://www.csiro.au/en/work-with-us/ip-commercialisation/hydrogen-technology-marketplace/metal-composite-pressurised-vessels> (accessed 10 May 2022); Langmi H, Engelbrecht N, Modisha P, Bessarabov D (2022) Hydrogen storage in electrochemical power sources: Fundamentals, systems and applications. In Hydrogen Production by Water Electrolysis. (Eds T Smolinka, J Garche) 455–486. Elsevier.

497 Steilen M, Jorissen L (2015) Conversion into electricity and thermal energy by fuel cells: Use of H_2-systems and batteries. In Electrochemical Energy Storage for Renewable Sources and Grid Balancing. (Eds PT Moseley, J Garche) 143–158. Elsevier, Amsterdam; Langmi et al. (2022) Hydrogen storage in electrochemical power sources: Fundamentals, systems and applications. In Hydrogen Production by Water Electrolysis. (Eds T Smolinka, J Garche) 455–486. Elsevier.

498 Steilen M, Jorissen L (2015) Conversion into electricity and thermal energy by fuel cells: Use of H_2-systems and batteries. In Electrochemical Energy Storage for Renewable Sources and Grid Balancing. (Eds PT Moseley, J Garche) 143–158. Elsevier, Amsterdam.

499 For a hydrogen system with an electrolyser, storage tank and fuel cell or up to 500 MW: Schmidt et al. (2019) Projecting the future levelized cost of electricity storage technologies. Joule 3, 81–100.

500 Based on one charge/discharge cycle per day for 300 days: Agostini A, Belmonte N, Masala A, Hu J, Rizzi P, Fichtner M, Moretto P, Luetto C, Sgroi M, Baricco M (2018). Role of hydrogen tanks in the life cycle assessment of fuel cell-based auxiliary power units. Applied Energy 215, 1–12.

501 The high pressure of storage tanks and the use of certain materials (such as alloys or high-strength steels that are more prone to embrittlement) heightens these risks: Elberry A, Thakur J, Santasalo-Aarnio A, Larmi M (2021) Large-scale compressed hydrogen storage as part of renewable electricity storage systems. International Journal of Hydrogen Energy 46, 15671–15690; Agostini et al. (2018) Role of hydrogen tanks in the life cycle assessment of fuel cell-based auxiliary power units. Applied Energy, 215, 1–12.

502 Andersson J, Grönkvist S (2019) Large-scale storage of hydrogen. International Journal of Hydrogen Energy 44, 11901–11919.

503 For example, at 45 bar, 12 tons of hydrogen may require 1,600 m2 horizontally compared with 260 m2 vertically (based on 29 pressure tanks, each with a volume of 115 m3): Wang Y, Kowal J, Leuthold M, Sauer D (2012) Storage system of renewable energy generated hydrogen for chemical industry. Energy Procedia 29, 657–667.

504 Elberry et al. (2021) Large-scale compressed hydrogen storage as part of renewable electricity storage systems. International Journal of Hydrogen Energy 46, 15671–15690.

505 IEA (2022) Global hydrogen review 2022. <https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf> (accessed 20 October 2022).

506 Harmsen N (2018) Hydrogen-fuelled power plant planned at Port Lincoln. ABC News. <https://www.abc.net.au/news/2018-02-12/hydrogen-power-plant-port-lincoln/9422022> (accessed 26 October 2022).

Hydrogen: Underground hydrogen

Electrochemical	Chemical	Mechanical	Thermal

What is it?

Underground hydrogen storage is a method for storing large quantities of hydrogen as an energy carrier. Hydrogen gas is compressed and injected into subsurface formations via wells. There are four main geological options for underground hydrogen: salt caverns, depleted oil and gas reservoirs, aquifers and hard rock caverns.

Why is it important?

Underground hydrogen is a promising option for large-scale energy storage.[507] It facilitates high-pressure storage of large volumes of hydrogen to provide for seasonal and on-demand energy requirements. Relative to other hydrogen storage options, underground hydrogen is a preferred option for large volumes of hydrogen for safety and cost reasons.[508] It has decreased risks of fires and gas leaks compared with other hydrogen storage methods. Moreover, it has been estimated that above-ground storage tanks can cost up to three- to fivefold more than geological storage, often with a lower storage capacity than below-ground options.[509]

Benefits[511]

- Facilitates high-volume storage with a small above-ground geographical footprint, allowing for better space management compared with other utility scale energy storage options
- High-volume storage can allow seasonal energy storage to buffer fluctuations in supply and demand, both for domestic use and export purposes
- Reduced safety and environmental risks compared with other large-scale energy storage technologies

Limitations[512]

- Geographical storage of hydrogen may require additional purification processes (i.e. to remove residual natural gas or sulfides produced via side reactions) that are not required with other hydrogen storage methods
- Storage efficiency depends on the geological properties of the underground formation (including fluid viscosity, groundwater flow, gas expansion and saturation)
- Although gas leaks are unlikely compared with above-ground tanks, because of its high mobility, hydrogen can penetrate and damage internal structures and may create hard-to-detect leaks

	RESEARCH AND DEVELOPMENT								DEMONSTRATION						DEPLOYMENT			
TRL[510]	1	2	3	4	5	6	7	8	9									
CRI		1							2		3		4		5		6	

507 CSIRO (n.d.) Hydrogen technology marketplace: Underground storage. <https://www.csiro.au/en/work-with-us/ip-commercialisation/hydrogen-technology-marketplace/Underground-storage> (accessed 9 May 2022).

508 Ennis-King J, Michael K, Strand J, Sander R, Green C (2021) Underground storage of hydrogen: Mapping out the options for Australia. Future Fuels CRC. <https://www.futurefuelscrc.com/project/underground-storage-of-hydrogen-mapping-out-the-options-for-australia-rp1-1-04/> (accessed 8 November 2022).

509 Sandia National Laboratories (2014) Storing hydrogen underground could boost transportation, energy security. Science Daily. <https://www.sciencedaily.com/releases/2014/12/141209091854.htm> (accessed 9 May 2022).

510 Technology and commercial readiness levels depend on the underground geological formation used. For example, depleted hydrocarbon reservoirs, aquifers and hard rock caverns are at TRL 5–7/CRI 1. However, for salt cavern formations, the maturity of hydrogen storage also depends on whether they are used for chemical storage (TRL 9/CRI 4) or grid-connected storage (TRL 8-9/CRI 2):

E.nnis-King et al. (2021) Underground storage of hydrogen: Mapping out the options for Australia. Future Fuels CRC. <https://www.futurefuelscrc.com/project/underground-storage-of-hydrogen-mapping-out-the-options-for-australia-rp1-1-04/> (accessed 8 November 2022); IEA (2022) Global hydrogen review 2022. <https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf> (accessed 20 October 2022).

511 Ennis-King et al. (2021) Underground storage of hydrogen: Mapping out the options for Australia. Future Fuels CRC. <https://www.futurefuelscrc.com/project/underground-storage-of-hydrogen-mapping-out-the-options-for-australia-rp1-1-04/> (accessed 8 November 2022); Muhammed N, Haq B, Shehru D, Al-Ahmed A, Rahman M, Zaman E (2022) A review on underground hydrogen storage: Insight into geological sites, influencing factors and future outlook. Energy Reports 8, 461–499.

512 Ennis-King et al. (2021) Underground storage of hydrogen: Mapping out the options for Australia. Future Fuels CRC. <https://www.futurefuelscrc.com/project/underground-storage-of-hydrogen-mapping-out-the-options-for-australia-rp1-1-04/> (accessed 8 November 2022); Zivar D, Kumar S, Foroozesh J (2020) Underground hydrogen storage: A comprehensive review. International Journal of Hydrogen Energy 46, 23436–23462; Godfrey et al. (2017) The role of energy storage in Australia's future energy supply mix. Australian Council of Learned Academies, Melbourne.

- TRL is dependent on local geological conditions. For example, hydrogen storage in underground salt caverns is being demonstrated at pilot scales (TRL 8–9/CRI 1–2), whereas storage in engineered hard rock caverns, depleted fields and aquifers requires further RD&D (TRL 5–7/CRI 1)[513]
- The availability of suitable salt deposits is limited in Australia; however, other underground storage options have been assessed and deemed to be potential reservoir candidates

Deployment considerations

- Construction time: 1–5 years, depending on size, geology and leaching method[514]
- Typical lifetime: 30 years[515]
- Maximum storage duration: Offers significant storage capacities, limited mainly by the volume of available underground sites[516]
- Inputs/outputs: Hydrogen
- External utilities: Surface-level infrastructure requirements may include hydrogen injection/extraction wells, compressor, dehydration unit, brine disposal mechanism and processing infrastructure to prepare hydrogen for end use
- Operating temperature: 30–80°C[517]
- Geographical considerations: Factors used to assess the suitability of underground formations include the tightness of the geological structures, geochemical and microbiological interactions with reservoir fluids and the volume of working gas[518]
- Safety/risk management: Hydrogen's high flammability may pose a fire and explosion risk. This risk is largely related to surface infrastructure and handling. Installation of safety valves can help avoid hydrogen leakage to the surface[519]
- Environmental and social considerations: Environmental assurance tests are required to monitor the pressure of injection wells, chemical levels in peripheral water wells and microbial levels within reservoirs during operation[520]
- Commercial and demonstration projects in Australia: Pilot-scale underground hydrogen projects are yet to be conducted in Australia

513 CSIRO (n.d.) Hydrogen technology marketplace: Underground storage. <https://www.csiro.au/en/work-with-us/ip-commercialisation/hydrogen-technology-marketplace/Underground-storage> (accessed 9 May 2022).

514 Although the actual construction of the underground hydrogen system may be completed within this time frame, in reality development will be highly dependent on site approval, funding and the establishment of appropriate regulatory frameworks for underground hydrogen in Australia: Kruck O, Crotogino F, Prelicz R, Rudolph T (2013) Overview on all known underground storage technologies for hydrogen. HyUnder. <http://hyunder.eu/wp-content/uploads/2016/01/D3.1_Overview-of-all-known-underground-storage-technologies.pdf> (accessed 8 November 2022); Stone HBJ, Veldhuis I, Richardson RN (2009) Underground hydrogen storage in the UK. In Underground Gas Storage: Worldwide Experiences and Future Development in the UK and Europe. (Eds DJ Evans, RA Chadwick). <https://pubs.geoscienceworld.org/gsl/books/book/1924/chapter/107515871/Underground-hydrogen-storage-in-the-UK> (accessed 8 November 2022).

515 Based on a 500,000-m3 storage salt cavern completing six cycles per year: Bünger U, Michalski J, Crotogino F, Kruck O (2016) Large-scale underground storage of hydrogen for the grid integration of renewable energy and other applications. In Compendium of Hydrogen Energy. Volume 4: Hydrogen Use, Safety and the Hydrogen Economy. (Eds M Ball, A Basile, T Veziroğlu) 133–163. Woodhead Publishing.

516 Minimal losses may occur over long periods of time (months to years) due to permeation into the containment material and potential bacterial side reactions: Evans LJ, Shaw T (2021) Long-duration H_2 storage in solution-mined salt caverns – Part 1. Gulf Energy. <Long duration hydrogen storage in solution-mined salt caverns-part-1> (accessed 9 May 2022).

517 CSIRO (n.d.) Hydrogen technology marketplace: Underground storage. <https://www.csiro.au/en/work-with-us/ip-commercialisation/hydrogen-technology-marketplace/Underground-storage> (accessed 9 May 2022).

518 Uliasz-MIsiak B, Lewandowska-Smierzchalska J, Matula R (2021) Selection of underground hydrogen storage risk assessment techniques. Energies 14, 8049.

519 Muhammed et al. (2022) A review on underground hydrogen storage: Insight into geological sites, influencing factors and future outlook. Energy Reports 8, 461–499.

520 Reitenbach V, Ganzer L, Albrecht D, Hagemann B (2015) Influence of added hydrogen on underground gas storage: A review of key issues. Environmental Earth Science 73, 6927–6937.

Hydrogen: Metal hydrides

Electrochemical	Chemical	Mechanical	Thermal

What is it?

Metal hydrides are chemical compounds in which hydrogen bonds to metal atoms. Hydrogen is stored in this 'solid state' under mild conditions and is released by adding heat to the system. Although this describes the chemical storage of metal hydrides, the temperature-dependent sorption processes can be harnessed to also store thermal energy and compress hydrogen (with the metal hydrides acting as a chemical compressor).[521]

Why is it important?

Metal hydrides offer storage at moderate pressure and retrieval at safe temperatures. The stability and reliability of metal hydrides make them valuable for storage applications in disaster-prone areas and for low, prolonged power requirements (i.e. medical equipment in remote areas).[522]

Benefits[525]

- Inherently safer than other hydrogen storage methods: storage can occur at more moderate temperatures (vs liquefied hydrogen) and pressures (vs pressurised gas)
- Systems require minimal ongoing maintenance[526]
- Systems can use waste heat, as opposed to electricity, to drive the compression of hydrogen[527]

Limitations

- External heat transfer and limited reversibility can impact hydrogen uptake/release kinetics and restrict the use of certain types of metal hydrides for some applications[528]
- The current generation of low-temperature metal hydrides may suffer from low gravimetric hydrogen density[529]
- High-temperature hydrides and light metal hydrides require high temperatures (~100–500°C) for rapid hydrogen release[530]
- Metal hydride storage systems are sensitive to air and humidity and require pure hydrogen for storage. As such, hydrogen may require additional purification steps to remove impurities (i.e. residual moisture and gases from electrolysis procedures)

	RESEARCH AND DEVELOPMENT						DEMONSTRATION			DEPLOYMENT								
TRL[523]	1	2	3	4	5	6	7	8	9									
CRI[524]		1							2		3		4		5		6	

521 Bruce S, Temminghoff M, Hayward J, Schmidt E, Munnings C, Palfreyman D, Hartley P (2018). National hydrogen roadmap. CSIRO, Australia; Møller K, Sheppard D, Ravnsbæk D, Buckley C, Akiba E, Li H, Jensen T (2017) Complex metal hydrides for hydrogen, thermal and electrochemical energy storage. Energies 10, 1645.

522 Bruce et al. (2018) National hydrogen roadmap. CSIRO, Australia.

523 Hydrides of very high hydrogen storage capacity (e.g. AlH_3) are low TRL because they are not reversible for hydrogen storage. Room-temperature hydrides of lower hydrogen capacity (<2 wt% H_2) are high TRL: Bruce et al. (2018). National hydrogen roadmap. CSIRO, Australia.

524 Coregas (2021) LAVO completes demonstration installation at Coregas. <https://www.coregas.com.au/news/2021/lavo-completes-demonstration-installation-at-coregas> (accessed 11 October 2022).

525 Hynes N, Sankaranarayanan R, Kannan P, Khan A, Khan A, Asiri A, Dzudzevic-Cancar H (2021) 14 – Solid-state hydrides for hydrogen storage. In Micro and Nano Technologies. (Eds F Sen, A Khan, A Asiri) 249–264. Elsevier.

526 Lototskyy M, Yartys V, Pollet B, Bowman R (2014) Metal hydride hydrogen compressors: A review. International Journal of Hydrogen Energy 39, 5818–5851.

527 Lototskyy et al. (2014) Metal hydride hydrogen compressors: A review. International Journal of Hydrogen Energy 39, 5818–5851.

528 Gonzalez E, Flores S, Luevanos A (2021) Nanomaterials: Recent advances for hydrogen production. In Handbook of Nanomaterials and Nanocomposites for Energy and Environmental Applications. (Eds O Kharissova, L Martines, B Kharisov) 1–27. Springer.

529 Abdin Z, Khalilpour K (2019) Single and polystorage technologies for renewable-based hybrid energy systems. In Polygeneration with Polystorage for Chemical and Energy Hubs. (Ed K Khalilpour) 77–131. Academic Press.

530 US Department of Energy (n.d.) Materials-based hydrogen storage. <https://www.energy.gov/eere/fuelcells/materials-based-hydrogen-storage> (accessed 23 May 2022).

Deployment considerations

- Construction time: Insufficient data
- Typical lifetime: 30 years (20,000 cycles)[531]
- Maximum storage duration: Suitable for long-duration storage (multiday), depending on the alloy and flow rate of hydrogen; for example, a 40-kWh system can power a household for more than 2 days[532]
- Inputs/outputs: Hydrogen and a heat source (or power source to supply heat) for the absorption/desorption processes[533]
- External utilities: Systems may require a heat storage tank, cooling tower/water and a power source (i.e. connection to a solar PV farm or electricity grid)[534]
- Operating temperature: Depends on metal hydride properties; generally, room temperature hydrides: 20–80°C;[535] high-temperature metal hydrides: >250°C[536]
- Geographical considerations: Land requirements depend on system and total storage capacity requirements; for example, a 40-kWh system is less than 2 metres long[537]
- Safety/risk management: Minimal safety concerns due to modest pressures and operating temperatures.[538] Risk management practices include appropriate ventilation, designing a 20% volume expansion for hydrogen absorption and disposal of certain alloys
- Environmental and social considerations: Disposal and recycling considerations for metals and alloys
- Commercial and demonstration projects in Australia: There are several projects underway in Australia, including a 120-kg metal alloy hydrogen storage system provided by Japan Steel Works at Griffith University's Sir Samuel Griffith Centre. In addition, LAVO has completed a demonstration installation at a Coregas facility in Adelaide and GHD has recently secured funding from the UK Government to install a demonstration plant featuring LAVO's hydrogen-based battery technology in England[539]

531 Based on the LAVO™ hydride hydrogen battery: LAVO (n.d.) Home. <https://lavo.com.au/> (accessed 23 May 2022).

532 LAVO (2021) LAVO welcomes New South Wales Government's commitment to the development of a local hydrogen industry. <https://www.lavo.com.au/blog/lavo-welcomes-new-south-wales-governments-commitment-to-the-development-of-a-local-hydrogen-industry> (accessed 8 November 2022).

533 Breeze P (2018) Hydrogen energy storage. In Power System Energy Storage Technologies. 69–77. Academic Press.

534 Endo N, Matsumura K, Kawakami Y, Ishida M, Maeda T (2016) Operation of metal hydride hydrogen storage systems for hydrogen compression using solar thermal energy. Journal of International Council on Electrical Engineering 6, 65–71.

535 Modi P, Aguey-Zinsou K (2021) Room temperature metal hydrides for stationary and heat storage applications: A review. Frontiers in Energy Research. doi:10.3389/fenrg.2021.616115

536 Hardy B, Corgnale C, Gamble S (2021) Operating characteristics of metal hydride-based solar energy storage systems. Sustainability 13, 12117.

537 Thornhill J (2020) Australian Tesla Powerwall rival set to bring hydrogen into your home. Australian Financial Review. <https://www.afr.com/technology/australian-tesla-powerwall-rival-set-to-bring-hydrogen-into-your-home-20201020-p566o1> (accessed 8 November 2022); Filatoff N (2021) Australian world-first domestic hydrogen battery signs an iconic investor. PV Magazine. <https://www.pv-magazine-australia.com/2021/01/25/australian-world-first-domestic-hydrogen-battery-signs-an-iconic-investor/> (accessed 8 November 2022).

538 Møller et al. (2017) Complex metal hydrides for hydrogen, thermal and electrochemical energy storage. Energies 10, 1645.

539 GHD (2022) GHD secures UK Government funding to trial longer duration hydrogen energy storage <https://www.ghd.com/en/news/ghd-secures-uk-government-funding-to-trial-longer-duration-hydrogen-energy-storage.aspx> (accessed 24 November 2022).Coregas (2021) LAVO completes demonstration installation at Coregas. <https://www.coregas.com.au/news/2021/lavo-completes-demonstration-installation-at-coregas> (accessed 8 November 2022).

THERMAL

- Thermal energy storage consists of sensible heat storage systems (energy released and stored by heating/cooling a solid or liquid storage medium), latent heat storage systems (energy released and stored with a change in physical state; also known as phase change storage) and thermochemical systems (energy released and stored via a reversible chemical reaction).[540]
- This roadmap considers three sensible energy storage systems (molten salt, graphite and silicon) and one latent energy storage system (MGAs).

Molten salts

Electrochemical	Chemical	Mechanical	**Thermal**

What is it?

Molten salts are a type of heat transfer fluid and storage medium that store thermal energy from an electrical or heat source (e.g. a solar collector). Once heated, the salts are sent to a hot storage tank for later use.

If power is required, the liquid molten salt is used to generate high-temperature steam, which is then used within a steam turbine at its optimal efficiency. The temperature-reduced salt is then stored in a second cold storage tank, where the cycle can be repeated.[541]

If heat is required, the high-temperature steam generated can be delivered at the required temperature and pressure levels, or the molten salts may be used directly for process heating as a heat transfer fluid or by using a heat exchanger.[542]

Why is it important?

Molten salts are a flexible and efficient heat storage medium. They have a greater operating temperature range (220–565°C) than other heat transfer fluids, so they can support a wider variety of power generation applications.[543] The tank storage system allows for multihour storage, which is typically between 6 and 18 hours in most operational systems. Further, molten salts have strong heat transfer capabilities, allowing for heat transfer efficiencies of up to 95%.[544]

	RESEARCH AND DEVELOPMENT							DEMONSTRATION						DEPLOYMENT			
TRL[545]	1	2	3	4	5	6	7	8	9								
CRI[545]		1							2		3		4		5		6

540 Sarbu I, Sebarchievici C (2018) A comprehensive review of thermal energy storage. Sustainability 10, 191.

541 The temperature of the hot tank is approximately 580°C, whereas that of the cold tank is around 300°C. However, this depends on the salt composition used.

542 MAN Energy Solutions (n.d.) MAN MOSAS: Molten salt energy storage. <https://www.man-es.com/docs/default-source/energy-storage/mosas-campaign/man-es_factsheets_4p_mosas.pdf?sfvrsn=7d9605c1_20> (accessed 9 September 2022).

543 Some molten salts have even lower temperature limits (down to 140°C), such as HITEC Heat Transfer Salt: Lovegrove et al (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/renewable-energy-options-for-industrial-process-heat.pdf> (accessed 21 October 2022).

544 SolarThermalWorld (2018) Molten salt storage 33 times cheaper than lithium-ion batteries. <https://solarthermalworld.org/news/molten-salt-storage-33-times-cheaper-lithium-ion-batteries/> (accessed 18 March 2022).

545 Power use with concentrated solar thermal (CST) input (TRL 9/CRI 4–5), power use with electrical input (TRL 7–8/CRI 1–2) and thermal use with CST input (TRL 6/CRI 1): IRENA (2020) Innovation outlook: Thermal energy storage. IRENA, Abu Dhabi; Italian National Agency for New Technologies, Energy and Sustainable Economic Development (ENEA) (n.d.) Use of molten salts as a thermal vector fluid and heat storage system at medium and high temperature. <https://www.enea.it/en/ateco/schede/molten-salts-thermal-vector-fluid-and-storage-medium-high-temperature> (accessed 8 November 2022); MAN Energy Solutions (n.d.) MAN MOSAS: Shaping the future of renewable energy. <https://www.man-es.com/energy-storage/solutions/energy-storage/mosas> (accessed 12 October 2022).

Benefits[546]

- Can operate at significantly higher temperatures than synthetic oils (up to 390°C) and other heat transfer fluids
- The combination of salts can be modified for operation at even lower temperatures (down to 150°C) to fit the end-use case[547]
- Experience minimal vapour pressure at high temperatures, reducing piping and equipment maintenance costs and supporting system longevity (vs synthetic oils)
- Are non-flammable and do not degrade over time (can be used for many years without being changed)
- Are relatively cheaper, denser and can retain more energy per volume than oil-based heat transfer fluids
- Have an excellent heat transfer capability, supporting both energy efficiency and operating costs

Limitations[548]

- Plant temperatures need to be maintained at or above melting temperatures or antifreeze systems need to be installed to prevent molten salts from hardening and blocking pipes or pumps
- Salts can decompose at higher temperatures, requiring regular maintenance and reducing the lifetime of these systems
- The level of corrosivity increases as the salt temperature increases; high-temperature (>600°C) molten salts can be highly corrosive

Deployment considerations

- Construction time: <2 years for a CST system[549]
- Typical lifetime: 20 years[550]
- Maximum storage duration: Systems are typically designed to provide up to 18 hours.[551] However, much longer durations are possible (e.g. a pilot-scale system could provide up to 200 hours of storage[552])
- External utilities: Heat source (typically an electric heating element), steam generator and turbine, condenser and antifreeze[553]
- Operating temperature: 220–565°C[554]
- Geographical considerations: Molten salt tanks are relatively compact (metres scale); however, if paired with a concentrated solar plant, the overall system can have significant land requirements (kilometres scale)
- Safety/risk management: Risks relating to human contact with molten salts or exposure to high temperatures produced by the system heat source can be minimised through safety practices.[555]
- Environmental and social considerations: Molten salts have a relatively low environmental impact (vs thermal energy storage using concrete). Waste recycling and low-emission transportation of construction materials can reduce this impact[556]
- Commercial and demonstration projects in Australia: There are currently no operational CST plants in Australia using molten salts; however, molten salts are the most widely deployed medium internationally for commercial CST systems[557]

546 WATTCO (n.d.) Applications & advantages of molten salt in heating systems. <https://www.wattco.com/2021/09/molten-salts-applications-advantages/> (accessed 10 March 2021).

547 Typical molten salt systems operate between 285°C and 565°C.

548 Cavanagh et al. (2015) Electrical energy storage: Technology overview and applications. CSIRO, Australia.

549 Figure is for a 150-MW concentrated solar power tower with molten salt storage: Aurecon (2020) 2020 Costs and technical parameter review. Aurecon, Brisbane.

550 IRENA (2020) Innovation outlook: Thermal energy storage. IRENA, Abu Dhabi.

551 Average duration of storage worldwide: Bauer T, Odenthal C, Bonk A (2021) Molten salt storage for power generation. Chemie Ingenier Technik 93, 534–546.

552 LDES Council (2022) Net-zero power: Long duration energy storage for a renewable grid. McKinsey & Company. <https://www.mckinsey.com/capabilities/sustainability/our-insights/net-zero-power-long-duration-energy-storage-for-a-renewable-grid> (accessed 8 November 2022).

553 IRENA (2020) Innovation outlook: Thermal energy storage. IRENA, Abu Dhabi.

554 Some molten salts have even lower temperature limits (down to 140°C), such as HITEC Heat Transfer Salt: Lovegrove et al (2019) Renewable energy options for industrial process heat. ITP Thermal, Turner. <https://arena.gov.au/assets/2019/11/renewable-energy-options-for-industrial-process-heat.pdf> (accessed 21 October 2022).

555 CESA (2017) Updates from the frontlines of ESS safety. <https://www.storagealliance.org/blog-feed/2018/10/8/updates-from-the-frontlines-of-ess-safety> (accessed 31 May 2022).

556 Low impact compared with thermal energy storage using concrete for use in CSP plants: Adeoye J, Amha Y, Poghosyan V, Torchyan K, Arafat H (2014) Comparative LCA of two thermal energy storage systems for Shams1 concentrated solar power plant: Molten salt vs. concrete. Journal of Clean Energy Technologies 2, 247–281.

557 IRENA (2020) Innovation outlook: Thermal energy storage. International Energy Agency, Abu Dhabi.

Graphite

Electrochemical | Chemical | Mechanical | **Thermal**

What is it?

Graphite blocks collect and store thermal energy from a heat source (i.e. solar or heating elements): the thermal energy from the source is transferred via a heat transfer fluid to a storage unit containing graphite blocks. When required, the thermal energy can be used to produce steam or hot air for industrial processes, or may be converted to electricity on demand via a thermophotovoltaic heat engine or steam generator.[558]

Why is it important?

Graphite blocks are a modular and flexible heat storage medium that use abundant and affordable materials. In addition to electricity production, graphite blocks can have mid- to high-temperature range thermal outputs that could support a range of industrial processes such as food manufacturing and fuel production. These systems are simple, with minimal installation and maintenance requirements, which may support operations in remote areas.

Benefits

- Graphite, as the main component of the energy storage system, is abundant and low cost
- The high thermal diffusivity of graphite improves consistencies in heat transfer, allowing for fast charging/discharging rates[561]
- Solid sensible storage materials like graphite offer larger temperature ranges than molten nitrate salts[562]
- Scalable and modular designs allow for greater flexibility in the capacity and duration of thermal storage[563]
- Systems allow for the simultaneous production of electricity and heat energy for polygeneration purposes

Limitations

- The power output from storage will change with time as the graphite cools during discharge[564]
- Above 400°C, an inert atmosphere is required to prevent oxidation of the graphite[565]
- Higher operating temperatures (e.g. over 650°C) accelerate ‘creep’, the deformation of the graphite due to stress despite operating at stress levels significantly below breaking strength[566]

	RESEARCH AND DEVELOPMENT						DEMONSTRATION						DEPLOYMENT					
TRL[559]	1	2	3	4	5	6	7	8	9									
CRI[560]		1							2		3		4		5		6	

558 Kelsall C, Buznitsky K, Henry A (2021) Technoeconomic analysis of thermal energy grid storage using graphite and tin. Cornell University ArXiv. doi:10.48550/arXiv.2106.07624

559 TRL 6–7 for power use and TRL 7–9 for thermal use: Saeed R, Frick K, Shigrekar A, Mikkelson D, Bragg-Sitton (2022) Mapping thermal energy storage technologies with advanced nuclear reactors. Energy Conversion and Management 267, 115872.

560 CRI 1 for power use and CRI 1–2 for thermal use: Putrill J (2022) A ‘graphite battery’ in Wodonga will be Australia’s first commercial thermal energy storage. ABC News. <https://www.abc.net.au/news/2022-08-04/graphite-battery-will-be-first-commercial-thermal-energy-storage/101295350> (accessed 28 September 2022); National Party of Australia (2021) Lake Cargelligo technology company to help drive down emissions thanks to $9.8 million investment. <https://www.markcoulton.com.au/lake-cargelligo-technology-company-to-help-drive-down-emissions-thanks-to-9-8-million-investment/> (accessed 11 October 2022).

561 Guan et al. (2020) Regulation of the output temperature in a novel water heating system using solid graphite as sensible heat thermal energy storage medium: Effects of water tank. Energy Reports 6 (Supplement 7), 160–171.

562 Ho C, Ambrosini A (2020) Thermal energy storage technologies. In U.S. DOE Energy Storage Handbook. <https://www.sandia.gov/ess/publications/doe-oe-resources/eshb> (accessed 17 June 2022).

563 Saeed et al. (2022) Mapping thermal energy storage technologies with advanced nuclear reactors. Energy Conversion and Management 267, 115872.

564 Kelsall et al. (2021) Technoeconomic analysis of thermal energy grid storage using graphite and tin. Cornell University ArXiv. doi:10.48550/arXiv.2106.07624

565 Bauer T, Steinmann W, Laing D, Tamme R (2012) Thermal energy storage materials and systems. Annual Review of Heat Transfer 15, 131–177.

566 MIT Energy Initiative (2022) The future of energy storage: An interdisciplinary MIT study. Massachusetts Institute of Technology. <https://energy.mit.edu/wp-content/uploads/2022/05/The-Future-of-Energy-Storage.pdf> (accessed 24 June 2022).

Deployment considerations

- Construction time: No data
- Typical lifetime: >30 years;[567] no cycling degradation
- Maximum storage duration: 8 hours[568]
- Inputs/outputs: Heat source or electricity for heat generation
- External utilities: Heat source, steam generator and turbine, heat transfer fluid (i.e. water), heat exchanger and pumps
- Operating temperature: Generally, systems operate from 200°C to over 750°C;[569] however, process heat outputs can vary according to application requirements.[570] For example, thermophotovoltaic systems can operate with heat outputs up to 1,500°C[571]
- Geographical considerations: Considered geographically insensitive, with modular systems (20-ft shipping containers) offering small, easily transportable parts that require little to no onsite construction.[572] Although relatively compact, if paired with a concentrated solar farm, the overall system can have significant land requirements (kilometres scale)
- Safety/risk management: Does not require the use of flammable or reactive materials. There is a low risk of thermal runaway
- Environmental and social considerations: Graphite has a relatively low environmental impact (vs TES using concrete). However, there are environmental and social considerations associated with graphite mining, including dust pollution, energy-intense processes and emissions production[573]
- Commercial and demonstration projects in Australia: Graphite Energy previously developed a 3.5-MW_e energy storage plant in Lake Cargelligo, NSW, and is developing a hybrid solar and graphite TES system referred to as 'Project Platypus'[574]

567 Kelsall et al. (2021) Technoeconomic analysis of thermal energy grid storage using graphite and tin. Cornell University ArXiv. doi:10.48550/arXiv.2106.07624

568 Based on Graphite Energy TES system demonstrations to date: Graphite Energy (n.d.) Industrial Heat Decarbonisation. < https://www.graphiteenergy.com/green-heat> (accessed 24 June 2022).

569 Guan et al. (2020) Regulation of the output temperature in a novel water heating system using solid graphite as sensible heat thermal energy storage medium: Effects of water tank. Energy Reports 6 (Supplement 7), 160–171; Graphite Energy (2022) Proven, reliable graphite thermal energy storage. <https://www.graphiteenergy.com/technology> (accessed 18 November 2022).

570 For example the Mars Wodonga demonstration project is designed to deliver 150–200°C process heat output: Graphite Energy (n.d.) Industrial heat decarbonisation. <https://www.graphiteenergy.com/green-heat> (accessed 17 June 2022).

571 Briggs J Antora Energy (2021) Solid State Thermal Battery. ARPA-E DAYS Annu. Meet., Advanced Research Projects Agency – Energy cited in Novotny et al. (2022) Review of Carnot battery technology commercial development. Energies 15, 647.

572 Saeed et al. (2022) Mapping thermal energy storage technologies with advanced nuclear reactors. Energy Conversion and Management 267, 115872.

573 Engels P, Cerdas F, Dettmer T, Frey C, Hentschel J, Herrmann C, Mirfabrikikar T, Schueler (2022) Life cycle assessment of natural graphite production for lithium-ion battery anodes based on industrial primary data. Journal of Cleaner Production 336, 130474.

574 The 3.5-MW_e demonstration project is no longer active: Graphite Energy (n.d.) Project Platypus: Solar TES hybrid plant. <https://www.graphiteenergy.com/platypus-tes-demonstration> (accessed 9 November 2022).

Silicon

Electrochemical | Chemical | Mechanical | **Thermal**

What is it?

Silicon TES systems involve the heating of silicon, which stores thermal energy that can be later released in the form of heat or power. In sensible heat designs, silicon is heated to increase its internal energy. In latent heat designs (≥1,414°C), heat energy is still stored; however, silicon undergoes a phase change (from solid to molten silicon). Upon melting, heat is transferred to the silicon and is stored at a constant temperature; the heat is released as the silicon solidifies upon cooling. When required, the heat energy can be released, therefore decreasing the internal energy of the silicon.[575] The heat energy can be used directly or it can be converted back to electricity by using either an energy recovery system involving a heat exchanger and power generation equipment (i.e. gas turbine, steam turbine, Stirling engine) or a thermophotovoltaic converter.[576]

Why is it important?

Silicon-based storage systems have high storage densities and low-complexity designs. Silicon thermal energy storage can further improve the energy density and conversion efficiency of non-silicon systems by allowing for high operating temperatures. This technology is well suited to provide heat for high-temperature industrial processes such as steel, aluminium, glass and ceramics. Where melting takes place to store energy as latent heat, this has the advantage that all the heat is available to be released at the high temperature of the phase change.

Benefits[579]

- Systems allow for the simultaneous production of electricity and heat energy for polygeneration purposes
- Silicon energy storage systems can be easily integrated into existing infrastructure, such as solar PV facilities, to support grid power demand when renewable energy is not available[580]
- Silicon can cycle at a high capacity for a long lifetime and has a high storage density
- Systems are scalable due to their modular construction

	RESEARCH AND DEVELOPMENT						DEMONSTRATION						DEPLOYMENT					
TRL[577]	1	2	3	4	5	6	7	8	9									
CRI[578]		1							2		3		4		5		6	

575 Sonar D (2020) Renewable energy based trigeneration systems – technologies, challenges and opportunities. In Renewable Energy Driven Future: Technologies, Modelling, Applications, Sustainability and Policies. (Ed J Ren) 125–168. Academic Press.

576 Ramos A, López E, Cañizo C, Datas A (2022) Cost-effective ultra-high temperature latent heat thermal energy storage systems. Journal of Energy Storage 49, 104131.

577 The TRL for silicon systems varies based on the system design and target temperature range. For a latent heat system, operating at ≥1,414°C, the TRL is 4–5 and CRI 1: 1414 Degrees (2021) SiBox commercialisation path. <https://1414degrees.com.au/sibox-commercialisation-path/> (accessed 8 November 2022).

578 1414 Degrees (2021) SiBox commercialisation path. <https://1414degrees.com.au/sibox-commercialisation-path/> (accessed 8 November 2022).

579 Parham J, Vrettos P, Levinson N (2021) Commercialisation of ultra-high temperature energy storage applications: The 1414 Degrees approach. In Ultra-High Temperature Thermal Energy Storage, Transfer and Conversion. (Ed A Datas) 331–346. Woodhead Publishing.

580 Merouch L, Chen G (2020) Thermal energy storage radiatively coupled to a supercritical Rankine cycle for electric grid support. Renewable Energy 145, 604–621.

Limitations

- Operating at ultrahigh temperatures may reduce the strength of containment vessels and increase the reactivity of materials.[581] High temperatures also necessitate the use of more expensive materials
- Residual heat loss and conversions of heat back to electricity can lower system efficiency[582]
- Upon solidifying, silicon expands up to 10%, which could damage containers and lead to engineering concerns over time[583]

Deployment considerations[584]

- Construction time: Insufficient data
- Typical lifetime: 30 years[585]
- Maximum storage duration: Typically 8 hours; however, much longer durations are targeted
- Inputs/outputs: The heating of silicon requires either electricity (renewable, fuel generated or off-grid) or fuels for combustion.[586] Outputs of heat and/or electricity
- External utilities: These systems are highly customisable in terms of energy inputs and heating apparatus. Infrastructure requirements typically include a silicon heat storage tank, energy recovery system (PV converter or heat exchanger, compressor, turbine, generator) and heating apparatus (boilers, electrical or existing infrastructure)
- Operating temperature: Latent heat systems (targeting silicon's melting point of 1,414°C) are in development[587]
- Geographical considerations: No geographical requirements, but the footprint will largely depend on system capacity. Facilities located alongside existing power plants or PV farms can leverage existing infrastructure to minimise capital costs
- Safety/risk management: High operating temperatures may pose a risk to the silicon vessel, the stability of working fluids and the mechanical strength of engine parts[588]
- Environmental and social considerations: Given combustion is not a requisite, silicon-based latent heat systems can be emission free. Silicon is non-toxic, abundant and fully recyclable, so resource scarcity is not a threat
- Commercial and demonstration projects in Australia: 1414 Degrees plan to demonstrate a silicon TESS-GRID system paired with a 400-MW solar farm to supply dispatchable electricity and provide grid-firming services[589]

581 Parham et al. (2021) Commercialisation of ultra-high temperature energy storage applications: The 1414 Degrees approach. In Ultra-High Temperature Thermal Energy Storage, Transfer and Conversion. (Ed A Datas) 331–346. Woodhead Publishing.

582 Ramos et al. (2022) Cost-effective ultra-high temperature latent heat thermal energy storage systems. Journal of Energy Storage 49, 104131.

583 Datas A, Ramos A, Martí A, Cañizo C, Luque A (2016) Ultra high temperature latent heat energy storage and thermophotovoltaic energy conversion. Energy 107, 542–549.

584 Meroueh L, Chen G (2020) Thermal energy storage radiatively coupled to a supercritical Rankine cycle for electric grid support. Renewable Energy 145, 604–621.

585 Ray A, Rakshit D, Ravikumar K (2021) High-temperature latent thermal storage system for solar power: Materials, concepts, and challenges. Cleaner Engineering and Technology 4, 100155.

586 Parham et al. (2021) Commercialisation of ultra-high temperature energy storage applications: The 1414 Degrees approach. In Ultra-High Temperature Thermal Energy Storage, Transfer and Conversion. (Ed A Datas) 331–346. Woodhead Publishing.

587 1414 Degrees (2021) Partnership with Woodside to progress the development of SiBox. <https://1414degrees.com.au/1414-degrees-woodside-partnership/> (accessed 28 November 2022).

588 Datas A, Zeneli M, Cañizo C, Malgarinos I, Nikolopoulos A, Nikolopoulos N, Karellas S, Martí A (2018) Molten silicon storage of concentrated solar power with integrated thermophotovoltaic energy conversion. AIP Conference Proceedings 2033, 090005.

589 1414 Degrees (2019) 1414 Degrees acquiring Aurora Project near Port Augusta. <https://1414degrees.com.au/acquiring-aurora-project/> (accessed 28 November 2022).

Miscibility gap alloys

Electrochemical	Chemical	Mechanical	Thermal

What is it?

MGAs are a microstructure formed between two metallic or semimetallic elements; a phase change material that exists as discrete particles, encapsulated within a material with a higher melting point. This gap in melting temperatures means that, upon heating, the phase change material melts (storing latent heat) while the other maintains the solid structure of the material (storing sensible heat). Upon cooling, heat is then transferred via heat exchangers or internal tubing into working fluids (steam or water) that operate a turbine or generator.[590]

Why is it important?

MGA systems provide a safe and cost-effective storage solution for large-scale energy storage applications. The storage medium is non-toxic, with no risk of exploding or combusting when exposed to hazardous environments. Further, MGA blocks are scalable and modular, and their ability to output both electricity and heat energy ensures they are well suited to supporting industrial demands for industrial process heat (particularly at a nominated temperature), power or a combination of both.[591]

The storage of heat in the phase change means that the majority of the heat can be recovered at a fixed high temperature of the phase change.

Benefits[594]

- Effective at heat transfer given that MGAs have a high thermal conductivity (30- to 200-fold that of molten salts). This can reduce the complexity and costs of insulation and heat exchanger infrastructure required
- Modular storage media such as MGA blocks can be stacked and scaled in insulated storage tanks. These blocks can also be manufactured and installed onsite as required
- Thermodynamically stable MGAs are expected to function for decades, with little maintenance required
- Systems allow for the simultaneous production of electricity and heat energy for polygeneration purposes
- The high energy density of latent heat storage can reduce the volume of storage required (vs molten salts)

Limitations

- MGA systems are not yet operational at large scales[595]
- The material and manufacturing costs of MGA blocks are more expensive (50–90% of system cost) than molten salts (30–50% of system costs), resulting in high upfront capital costs[596]

				RESEARCH AND DEVELOPMENT						DEMONSTRATION						DEPLOYMENT		
TRL[592]	1	2	3	4	5	6	7	8	9									
CRI[593]		1							2		3		4		5		6	

590 Kisi E, Sugo H, Cuskelly D, Fiedler T, Rawson A, Post A, Bradley J, Copus M, Reed S (2018) Miscibility gap alloys: A new thermal energy storage solution. In Transition Towards 100% Renewable Energy. (Ed A Sayigh) 523–532. Springer, Cham; Cuskelly D, Fraser B, Reed S, Post A, Copus M, Kisi E (2019) Thermal storage for CSP with miscibility gap alloys. AIP Conference Proceedings 2126, 200013.

591 The University of Newcastle (n.d.) The missing block to build an all-renewable grid. <https://www.newcastle.edu.au/newsroom/stories/the-missing-block-to-build-an-all-renewable-grid> (accessed 26 April 2022).

592 MGA Thermal (2022) MGA Thermal pilot. <https://mgathermal.com/pilot> (accessed 8 November 2022).

593 MGA Thermal (2022) MGA Thermal pilot. <https://mgathermal.com/pilot> (accessed 8 November 2022).

594 Kisi et al. (2018) Miscibility gap alloys: A new thermal energy storage solution. In Transition Towards 100% Renewable Energy. (Ed A Sayigh) 523–532. Springer, Cham; Cuskelly et al. (2019) Thermal storage for CSP with miscibility gap alloys. AIP Conference Proceedings 2126, 200013.

595 Internal source.

596 Range shows difference in melting points between Sn and Si MGA: Post A, Rawson A, Sugo H, Cuskelly D, Copus M, Bradley J, Kisi E (2017) Price estimation for miscibility gap alloy thermal storage systems. Renewable Energy and Environmental Sustainability 2, 32.

- System costs are linked to the cost of MGA blocks; therefore, increasing system capacities may not deliver significant cost benefits
- To benefit from the phase change, the melting point of the phase change material must be aligned to the temperature of the end-use process. For different end-use process temperatures, different phase change materials will be needed

Deployment considerations[597]

- Construction time: Insufficient data[598]
- Typical lifetime: over 20 years[599]
- Maximum storage duration: Around 24 hours; however, much longer durations are possible depending on the end-use application[600]
- External utilities: A heat source such as CST or electricity input for eTES systems, electric heaters to store energy in insulated containers[601] and steam turbines to produce electricity when needed
- Operating temperature: Theoretical range is 232–1,414°C;[602] however, the realistic upper limit is approximately 800°C
- Geographical considerations: Reduced land footprint compared with other thermal storage systems because MGA have a high energy density[603]
- Safety/risk management: MGA offer thermal stability long term, with no risk of explosion or combustion in hazardous environments
- Environmental and social considerations: MGA can be recycled and can be built from abundant materials[604]
- Commercial and demonstration projects in Australia: There are no operating MGA systems in Australia. However, MGA Thermal has received funding from the Australian Renewable Energy Agency to design and pilot a 5-MWh_{th} system[605]

597 The University of Newcastle (n.d.) The missing block to build an all-renewable grid. <https://www.newcastle.edu.au/newsroom/stories/the-missing-block-to-build-an-all-renewable-grid> (accessed 26 April 22).

598 Approximately 6–12 months for a demonstration-scale facility of 0.5 MW/5 MWh. MGA Thermal and ARENA demonstration project construction commenced August 2022, with estimated completion in early 2023: MGA Thermal (2022) MGA Thermal pilot. <https://mgathermal.com/pilot> (accessed 9 November 2022); ARENA (2022) Thermal energy: Can MGA fill a battery gap? ARENAWIRE. <https://arena.gov.au/blog/thermal-energy-can-mga-fill-a-battery-gap/> (accessed 9 November 2022).

599 Figure represents the lifetime of an MGA system used daily: Post et al. (2017) Price estimation for miscibility gap alloy thermal storage systems. Renewable Energy and Environmental Sustainability 2, 32.

600 Figure represents latent heat storage technologies: LDES Council (2022) Net-zero power: Long duration energy storage for a renewable grid. McKinsey & Company. <https://www.mckinsey.com/capabilities/sustainability/our-insights/net-zero-power-long-duration-energy-storage-for-a-renewable-grid> (accessed 8 November 2022).

601 Cuskelly et al. (2019) Thermal storage for CSP with miscibility gap alloys. AIP Conference Proceedings 2126, 200013.

602 Range shows the difference in melting points between Sn and Si MGA: Post et al. (2017) Price estimation for miscibility gap alloy thermal storage systems. Renewable Energy and Environmental Sustainability 2, 32.

603 The actual footprint will depend on system capacity: Kisi et al. (2018) Miscibility gap alloys: A new thermal energy storage solution. In Transition Towards 100% Renewable Energy. (Ed A Sayigh) 523–532. Springer, Cham.

604 MGA Thermal (n.d.) About MGA Thermal. <https://www.mgathermalstorage.com/about> (accessed 26 April 2022).

605 ARENA (n.d.) MGA thermal energy storage project. <https://arena.gov.au/projects/mga-thermal-energy-storage-project/> (accessed 9 November 2022).

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