2025 Energy Technology Cost and Technical Parameter Review

Draft Report (Rev C)

Australian Energy Market Operator Limited

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→ **The Power of Commitment**

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The Power of Commitment

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Appendices

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Appendix B	Equipment Cost Factor Region Maps
Appendix C	GHD's 2025 Energy Technology Retirement Cost & O&M Estimate Review

1. Introduction

The Australian Energy Market Operator (AEMO), in partnership with Commonwealth Scientific and Industrial Research Organisation (CSIRO), requires a revised dataset each year to support its forecasting and planning functions related to the cost of development, operations and maintenance (O&M) and retirement of existing electricity generation facilities across the National Energy Market (NEM), as well as emerging electricity generation technologies for use in the 2026 GenCost Report (prepared by CSIRO) and subsequently the 2026 Integrated System Plan (ISP).

GHD have been engaged by AEMO to provide this 2025 Energy Technology Cost and Technical Parameter Review Report and accompanying 2025 Dataset (excel) (together, Report), as an update for AEMO on existing cost of development, O&M and / or retirement for the technologies listed to support its forecasting and planning activities. The preceding Energy Technology Cost and Technical Parameter Review Report and accompanying dataset was completed by Aurecon in 2024[1].

This Report is a high-level Report and should be read in this context, in conjunction with the limitations, assumptions and qualifications contained in Section 1 and throughout this Report.

The existing and emerging electricity generation and storage technologies reviewed in this Report include:

1. **Generation technologies:**
   – Wind - Onshore
   – Wind - Offshore (Fixed)
   – Wind - Offshore (Floating)
   – Solar photovoltaic (PV) - Single axis tracking - Large Scale
   – Distribution-scale solar (single axis tracking) - Small
   – Distribution-scale solar (single axis tracking) - Large
   – Behind-the-meter scale solar (rooftop)
   – Wave
   – Tidal Stream
   – Solar Thermal Central Receiver with storage
   – Reciprocating Internal Combustion Engines, hydrogen ready (25%)
   – Advanced Ultra Super-critical Pulverised Coal (PC) - Black coal with (Carbon Capture and Storage Sequestration) CCS (90% capture)
   – Advanced Ultra Super-critical PC - Black coal with CCS (50% capture)
   – Advanced Ultra Super-critical PC - Black coal without CCS
   – Sub-critical - Black Coal, Small without CCS
   – Sub-critical - Black Coal, Small with CCS
   – Sub-critical - Black Coal, Large without CCS
   – Sub-critical - Black Coal, Large with CCS
   – Super-critical - Black Coal, Small without CCS
   – Super-critical - Black Coal, Small with CCS
   – Super-critical - Black Coal, Large without CCS
   – Super-critical - Black Coal, Large with CCS
   – Sub-critical - Brown Coal, Small without CCS
   – Sub-critical - Brown Coal, Small with CCS
   – Sub-critical - Brown Coal, Large without CCS

[1] Aurecon (2024) Energy Technology Cost and Parameters Review – Revision 3

- Sub-critical - Brown Coal, Large with CCS
- Open Cycle Gas Turbine (OCGT) - Small Aero-derivative, hydrogen ready (35%)
- OCGT - Large Aero-derivative, hydrogen ready (35%)
- OCGT - Small Industrial, hydrogen ready (10-15%)
- OCGT - Large Industrial, hydrogen ready (10%)
- Combined Cycle Gas Turbine (CCGT) - With Carbon Capture and Storage (CCS) (90%)
- CCGT - With CCS (50%)
- CCGT - Without CCS
- Biogas systems
- Landfill gas
- Biodiesel production
- Biomass generators using wood waste
- Waste to energy

2. **Hydrogen-based technologies and storage:**
   - Electrolysers - Proton Exchange Membrane
   - Electrolysers - Alkaline
   - Fuel cells - Small
   - Fuel cells - Large
   - Steam Methane Reforming (SMR)
   - SMR with CCS
   - Hydrogen storage
   - Hydrogen storage (geological)
   - Liquefaction plant and storage
   - Ammonia production Facility
   - Desalination plant (large scale)
   - Demineralisation plant
3. **Hydropower and energy storage:**
   - Conventional hydropower
   - Pumped hydroelectric storage (10 hr)
   - Pumped hydroelectric storage (24 hr)
   - Pumped hydroelectric storage (48 hr)
   - Pumped hydroelectric storage (160 hr)
   - Battery energy storage system (BESS)
   - Large Scale Li-ion Battery Storage (1 hr)
   - Large Scale Li-ion Battery Storage (2 hr)
   - Large Scale Li ion Battery Storage (4 hr)
   - Large Scale Li ion Battery Storage (8 hr)
   - Large Scale Flow Battery Storage (8 hr)
   - Large Scale Flow Battery Storage (12 hr)
   - Large Scale Battery Storage (1 hr) for hybrid generation
   - Large Scale Battery Storage (2 hr) for hybrid generation
   - Large Scale Battery Storage (4 hr) for hybrid generation
   - Large Scale Battery Storage (8 hr) for hybrid generation

  - Large Scale Flow Battery Storage (8 hr) for hybrid generation
  - Large Scale Flow Battery Storage (12 hr) for hybrid generation
  - Residential Battery Storage (2 hr)
4. **Compressed Air Energy Storage (CAES)**
  - Compressed Air Energy Storage (8 hr cavern storage)
  - Compressed Air Energy Storage (12 hr vessel storage)

1.1 Purpose of this Report

The purpose of this Report is to provide updated (as of 01 July 2025) input data regarding economic and technical parameters for AEMO relating to the development, O&M, and / or retirement of existing and emerging energy generation and storage technologies across the NEM for use in AEMO and CSIRO forecasting and planning studies.

1.2 Scope

The scope of this Report was based on three main tasks:

1. Development of a draft dataset and accompanying draft Report outlining key updates to AEMO's most recent set of energy technology cost input data (as prepared by Aurecon in 2024[2]) for a list of new entrant technologies and existing plants determined by AEMO including:
   a. Current costs and technical operating parameters for existing energy technologies and those with minimal current deployment, either locally or internationally.
   b. Costs and operating parameters for emerging technologies, including considerations for potential development locations, development limits, construction lead-times, and estimates of earliest commercial viability dates.
   c. Fixed and variable operation and maintenance and retirement cost estimates for all existing coal and gas plants in the NEM.
   d. Retirement costs including recycling costs for all existing and new generation, storage, electrolyser technologies in the NEM and the Inputs, Assumptions and Scenarios Report (IASR) scenarios.
   e. Sites, locations, maximum build capacity, and locational cost factors for potential pumped-hydro energy storage in the NEM.
2. Peer Review Process, including:
   a. Participate in an industry stakeholder workshop (CSIRO's GenCost 2025-26 workshop).
   b. Participate in a public-facing workshop.
   c. Consolidate and include stakeholder feedback into the draft dataset and Report where appropriate.
   d. Develop a Consultation Conclusion Report.
3. Prepare final dataset and Report.

1.3 Limitations

This Report: has been prepared by GHD for Australian Energy Market Operator Limited and may only be used and relied on by Australian Energy Market Operator Limited for the purpose agreed between GHD and Australian Energy Market Operator Limited as set out in section 1.1 of this Report and is not intended for use for any other purpose.

GHD otherwise disclaims responsibility to any person other than Australian Energy Market Operator Limited arising in connection with this Report. This Report must not, without prior written consent of GHD, be used or relied on by any other entity or person other than AEMO. Any use of, or reliance on, this Report by any third party is at the risk of that party. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this Report were limited to those specifically detailed in the Report and are subject to the scope limitations set out in this Report.

[2] Aurecon (2024) Energy Technology Cost and Parameters Review – Revision 3

The opinions, conclusions and any recommendations in this Report are based on conditions encountered and information reviewed at the date of preparation of this Report. GHD has no responsibility or obligation to update this Report to account for events or changes occurring subsequent to the date that this Report was prepared.

The opinions, conclusions and any recommendations in this Report are based on assumptions made by GHD described throughout this Report. GHD disclaims liability arising from any of the assumptions being incorrect.

GHD has prepared this Report on the basis of information sourced by, and provided to, GHD (including Government authorities), which GHD has not independently verified or checked. GHD does not accept liability in connection with such unverified information, including errors and omissions in this Report which were caused by errors or omissions in that information.

GHD has prepared the cost estimates set out throughout this Report ("Cost Estimates") using information reasonably available to the GHD employees who prepared this Report; and based on assumptions and judgments made by GHD as detailed in this Report. All cost related information being in real 2025 Australian Dollars for base estimates, with no allowances for escalation or inflation. The Cost Estimate is high-level and is not suitable for budgeting purposes. In some cases, the cost from the Dataset has been rounded within this Report for simplicity, given the Class 5 nature of this review, hence there may be some minor discrepancies between the associated costs.

The Cost Estimate has been prepared for the purpose of informing AEMO of current development, operation, and retirement costs (where applicable) of specific power generation and storage technologies and must not be used for any other purpose.

The Cost Estimate is a preliminary estimate, relevant to Class 5 estimates or Order of Magnitude only. Actual prices, costs and other variables may be different to those used to prepare the Cost Estimate and may change. Unless as otherwise specified in this Report, no detailed quotation has been obtained for actions identified in this Report. GHD does not represent, warrant or guarantee that the projects can or will be undertaken at a cost which is the same or less than the Cost Estimate.

Where estimates of potential costs are provided with an indicated level of confidence, notwithstanding the conservatism of the level of confidence selected as the planning level, there remains a chance that the cost will be greater than the planning estimate, and any funding would not be adequate. The confidence level considered to be most appropriate for planning purposes will vary and therefore the estimates provided in this Report should not be used for budgeting purposes.

Some outputs presented in this Report have been generated using Thermoflow Inc© software. The provider of this software does not guarantee the results obtained from its use, nor accept liability for any damages claimed due to its use or misuse. GHD's report is supplied strictly on the understanding that the outputs generated are accurate, complete, and sufficient. GHD assumes no responsibility and disclaims all liability for any loss or damage that AEMO may incur as a result of relying on conclusions drawn from outputs generated by GHD using this software.

1.4 Acronyms and abbreviations

Table 1.1 Acronyms and abbreviations

Acronym	Definition
2024 report	Aurecon 2024 Energy Technology Cost and Technical Parameter Review Report
AACE	Association for the Advancement of Cost Engineering
AC	Alternating Current
A-CAES	Adiabatic Compressed Air Energy Storage
AD	Anaerobic Digestion
AEM	Anion Exchange Membrane (Electrolyser)
AEMO	Australian Energy Market Operator
AGIG	Australian Gas and Infrastructure Group
ANU	Australian National University
ARENA	Australian Renewable Energy Agency
ATJ	Alcohol-to-Jet
AUD or A$	Australian Dollar
AUSC	Advanced Ultra-super-critical
B	Billion
BAU	Business As Usual
BESS	Battery Energy Storage System
BMS	Battery Management System
BIPS	Barker Inlet Power Station
BOP	Balance of Plant
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenditure
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon Capture and Storage
CH_4	Methane
CHP	Combined Heat and Power
CIP	Clean-In-Place
CO_2	Carbon Dioxide
COD	Commercial Operation Date
CPI	Consumer Price Index
CST	Concentrated Solar Thermal
DC	Direct Current
DLN	Dry Low NOx
D&C	Design and Construct
ED	Electrodialysis
EDI	Electrodeionization
EFOR	Equivalent Forced Outage Rate
EPC	Engineer Procure and Construct
FAME	Fatty Acid Methyl Ester (Biodiesel)
FEED	Front End Engineering and Design
FGD	Flue Gas Desulfurization
FID	Final Investment Decision
GJ	Gigajoule

Acronym	Definition
GMI	Global Market Insights
GST	Goods and Services Tax
GT	Gas Turbine
GW	Gigawatt
HDPE	High-density Polyethylene
HEFA	Hydroprocessed Esters and Fatty Acids
HHV	Higher Heating Value
HP	High Pressure
Hr	Hour
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
HVO	Hydrotreated Vegetable Oil
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IRENA	International Renewable Energy Agency
ISP	Integrated System Plan
Kg	Kilogram
Km	Kilometre
KOH	Potassium Hydroxide
kPa	Kilopascal
kW	Kilowatt
kWh	Kilowatt Hour
LCOA	Levelised Cost of Ammonia
LCOE	Levelised Cost of Electricity
LFG	Landfill Gas
LFP	Lithium Iron Phosphate
LHV	Lower Heating Value
Li-ion	Lithium ion
LTESA	Long Term Energy Service Agreement
M	Metre
M	Million
Mbgl	Metres below ground level
MCR	Maximum Continuous Rating
MED	Multi-Effect Distillation
Min	Minute
Mm	Millimetre
MSF	Multi-Stage Flash
MSW	Municipal Solid Waste
MPa	Megapascal
MV	Medium Voltage
MW	Megawatt
MWh	Megawatt-hour
NaS	Sodium-sulphur
NCA	Lithium Nickel Cobalt Aluminium Oxide
NEM	National Electricity Market
NER	National Electricity Rules

Acronym	Definition
NH_3	Ammonia
NMC	Lithium Nickel Manganese Cobalt Oxide
NOx	Nitric Oxide
NREL	National Renewable Energy Laboratory
NTP	Notice to Proceed
O&M	Operations and Maintenance
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
OTEC	Ocean Thermal Energy Conversion
PAFC	Phosphoric Acid Fuel Cell
PC	Pulverised Coal
PCB	Polychlorinated Biphenyl
PEM	Proton Exchange Membrane
PEMFC	Proton Exchange Membrane Fuel Cell
PHES	Pumped Hydropower Energy Storage
PJ	Petajoule
PPI	Producer Power Index
PTC	Parabolic Trough Collectors
PV	Photovoltaic
RBA	Reserve Bank of Australia
RBESS	Residential Battery Energy Storage System
RDF	Refuse-derived Fuel
Report	2025 Energy Technology Cost and Technical Parameter Review Report and accompanying 2025 Dataset (excel)
REZ	Renewable Energy Zone
RO	Reverse Osmosis
RPM	Revolutions per minute
RRB	Rolls Royce Bergen
RTE	Round Trip Efficiency
SAF	Sustainable Aviation Fuel
SAT	Single-axis Tracking
SCR	Selective Catalytic Reduction
SDI	Silt Density Index
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolyser Cells
SOFC	Solid Oxide Fuel Cell
SOx	Sulphur Oxides
SWRO	Seawater Reverse Osmosis
T	Tonne
TES	Thermal Energy Storage
tpa	Tonnes per annum
TRL	Technology Readiness Level
TVC	Thermal Vapor Compression
UCO	Used Cooking Oil
UF	Ultrafiltration

Acronym	Definition
USC	Ultra-super-critical
USD	United States Dollar
VPP	Virtual Power Plant
VRFB	Vanadium-Redox Flow Batteries
WEC	Wave energy converters
WEM	Wholesale Electricity Market
WGS	Water-gas Shift
WtE	Waste to Energy
WTG	Wind Turbine Generator
yr	Year

2. Approach & Methodology

2.1 Approach

The technologies and hypothetical projects used in this Report and accompanying dataset have been agreed with AEMO and are reflective of facilities currently installed in the NEM or have potential to be installed in the NEM. The technologies and hypothetical projects considered are largely consistent with those outlined in the *Aurecon 2024 Energy Technology Cost and Technical Parameter Review* [3] report as requested by AEMO.

Where possible, development, O&M, and retirement cost estimates were based on:

– GHD's internal project database
– Industry publications, credible and reliable publicly available information and published reputable industry databases
– CCS costs were obtained using a recognised reputable commercially available software package (Thermoflow)

This Report also examined recent market trends that could impact the development, operation, and retirement of generation and storage facilities across different technologies. Various factors were considered that may affect the costs and technical parameters of these technologies. These trends are presented in each section of this Report and were considered and incorporated into the cost estimates where applicable.

2.2 Methodology

Following project commencement, GHD conducted a high-level review of available literature and relied on current market understanding to summarise for each technology the typical options available in the market and recent trends. Using this understanding, hypothetical projects were developed for each technology for the purpose of cost estimation. In many instances and unless specified, the hypothetical projects remain unchanged from the *Aurecon 2024 Energy Technology Cost and Technical Parameter Review* [4] for consistency and ease of comparison. Where hypothetical projects have been changed, an explanation is provided to explain the basis for this adjustment.

2.2.1 Development cost estimates

The development cost estimates were generated using GHD internal project experience, industry knowledge, and reliable publicly available information and include estimates of:

– Equipment costs
– Installation costs
– Fuel connection costs
– Land and development costs

Note that development cost estimates will be subjective for each asset as costs are subject to a wide range of asset and situation specific factors. These factors include, but are not limited to:

– Technology type (incl. Original Equipment Manufacturer (OEM)) and maturity
– Asset location
– Site accessibility and terrain
– Market conditions
– Construction duration and sequencing

[3] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)
[4] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)

The development estimates are not intended for budgeting purposes associated with individual assets. Further assessment to understand development costs for assets on an individual basis should be undertaken to refine confidence in cost estimates as needed.

In some cases, the cost from the Dataset has been rounded within this Report for simplicity, given the Class 5 nature of this review, hence there may be some minor discrepancies between the associated Dataset and Report costs.

2.2.2 O&M cost estimates

O&M cost estimates were prepared using either benchmarks or a high-level 'bottom-up' cost estimation methodology to estimate fixed and variable O&M costs. The preparation of these cost estimates considered the following cost drivers based on GHD internal project experience, industry knowledge, and GHD's *2025 Energy Technology Retirement Cost & O&M Estimate Review* report for AEMO and published on the AEMO website[5] and attached in Appendix C:

Fixed O&M

– Labour costs
– Routine maintenance costs
– Contractor and consultant costs associated with general operations

Variable O&M

– Consumables costs
– Scheduled term maintenance costs
– Long term maintenance costs

Fuel costs, which represent a material variable O&M cost, have not been included. Note that O&M cost estimates will be subjective for each asset as costs are subject to a wide range of asset and situation specific factors. These factors include, but are not limited to:

– Organisation operating philosophy
– Market prices for consumables
– Competitive market forces for equipment and services such as contractor and consultant fees
– OEM recommended maintenance needs
– Asset location
– Insurance premiums

The O&M estimates are not intended for budgeting purposes associated with individual assets. Further assessment to understand O&M costs for assets on an individual basis should be undertaken to refine confidence in cost estimates as needed.

2.2.3 Retirement cost estimates

In July 2025, GHD published retirement cost estimates in a separate AEMO commission. The output of this commission was the *2025 Energy Technology Retirement Cost & O&M Estimate Review* Report[6] and dataset[7] and used the following methodology for estimating retirement, decommissioning, disposal and recycling costs for existing and new technologies:

1. Review existing AEMO datasets.
2. Define and agree scenarios with AEMO to be included in the review.

[5] **https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/ghd-2025-energy-technology-retirement-cost-om-estimate-review.pdf?la=en#:~:text=This%20study%20by%20GHD%20provides%20an%20update%20for,data%20to%20support%20its%20forecasting%20and%20planning%20activities.**
[6] 2025 Energy Technology Retirement Cost & O&M Estimate Review report, GHD, July 2025
[7] 2025 Energy Technology Retirement Cost & O&M Estimate Review dataset, GHD, July 2025

3. Undertake review of reputable publicly available information to define relevant market trends with potential to impact retirement estimates.
4. Identify key components of each technology relevant to retirement.
5. Define high-level retirement process.
6. Define assumptions and technology boundaries.
7. Update retirement and recycling cost estimates based on:
   a. GHD internal project information
   b. Generator provided information
   c. Publicly available credible and reliable information

The retirement costs published in GHD's *2025 Energy Technology Retirement Cost & O&M Estimate Review* Report have been carried over into this Report, however details regarding the key components relevant to retirement, the retirement process, and the defined assumptions and technology boundaries (step 4-6) remain within the separate GHD Report. To review this further detail, refer to GHD's *2025 Energy Technology Retirement Cost & O&M Estimate Review* report which is attached in Appendix C.

The retirement estimates are not intended for budgeting purposes associated with individual assets. Further assessment to understand retirement costs for assets on an individual basis should be undertaken to refine confidence in cost estimates as needed.

2.3 Assumptions

2.3.1 General

The cost estimates presented in this Report have been developed based on the following general, high-level assumptions. In addition, each technology will have its own set of specific assumptions which guide the cost estimation process. These technology specific assumptions are presented in the respective Report sections.

The general assumptions used to generate the cost estimates presented in this Report are:

– All costs are based on 2025 activity, in real 2025 Australian dollars, and are exclusive of GST. No allowances for escalation or inflation have been made.
– Cost estimates are reflective of a project being developed, operated, or retired on 01 July 2025.
– Assumptions related to retirement costs are outlined within GHD's *2025 Energy Technology Retirement Cost & O&M Estimate Review* Report (Appendix C).
– Cost estimates have not considered project contingencies (including risk of schedule delays).
– Inflation has been calculated using Australian June 2025 Producer Price Indexes for the Output of Heavy and civil engineering construction prices[8].
– Foreign exchange rates have been calculated using the Reserve Bank of Australia's (RBA) exchange rates[9] at the day of calculation / writing (September 2025).
– Cost estimates are provided generally consistent with Association for the Advancement of Cost Engineering (AACE) Class 5 as per 18R-97: Cost Estimate Classification System as Applied in Engineering, Procurement and Construction for the Process Industries where possible. Where AACE Class 5 confidence for value estimates is unable to be achieved (i.e. select new entrant or emerging technologies including ocean and wave technologies, concentrated solar thermal, geological hydrogen storage and compressed air energy storage), values will be provided based on relevant available information. A typical Class 5 estimate may have an accuracy range as broad as -50% to +100%[10]
– Where cost estimates have been used as a basis for further calculations, for example where a function of CAPEX has been used to estimate costs such as land and development costs, operational costs or

[8] Australian Bureau of Statistics, Producer Price Indexes, Australia June 2025 - Output of Heavy and civil engineering construction prices, quarterly percentage change and index**: https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/producer-price-indexes-australia/latest-release**
[9] Reserve Bank of Australia, Exchange Rates**, Exchange Rates | RBA**
[10] 18R-97: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries

retirement costs, the resultant cost number has generally been retained in full for accuracy noting that significant figures may appear unrealistic for Class 5 estimate.

– Fuel costs and sustaining capital values are generally excluded from O&M estimates unless stated.
– The Rawlinsons Australian Construction Handbook 2025[11] was used to form the basis of the location cost factors in Section 8.
– The following have not been considered as part of the preparation of this Report:
  - Climate change
  - Changes to regulations and legislation
  - Existing contractual liabilities for existing assets
  - Technological changes and advances beyond the scenarios described
  - Potential impacts on heritage and cultural artefacts
  - Land tenure agreements for existing assets
  - Any changes to market costs associated with changes in exchange rates and premiums or access associated with availability of contractors and equipment

2.3.2 Power generation / storage facility

Unless expressly outlined in the Report, power generation or storage facility equipment and installation scope is based on the assumptions described below.

Table 2.1 Power generation / storage facility key assumptions

Item	Detail
Site	Greenfield site (clear, flat, no significant cut and fill required, NEM installation, coastal location (within 200 km of coast within metro areas))
Base ambient conditions:	Dry Bulb Temperature: 25 °C Elevation above sea level: 110 metres Relative Humidity: 60%
Fuel quality	Gas: Standard pipeline quality natural gas (HHV to LHV ratio of 1.107) Diesel: No.2 diesel fuel Coal: Black coal Biomass: Woodwaste Waste: Municipal solid waste
Water quality	Towns water quality (i.e. potable) Demineralised water produced on site if required
Hydrogen quality	99.99+% v/v in compliance with ISO 14687-2:2014 and SAE J2719. HHV to LHV ratio of 1.183
Grid connection voltage	220 – 330 kV[12]
Grid connection infrastructure	Step-up transformer included switchyard / substation excluded
Energy Storage	Concentrated solar thermal – 14-hour thermal energy storage considered Electrolysers / hydrogen power generation (fuel cells / reciprocating engines / turbines) – Hydrogen compression, transport and storage excluded (relative costs provided separately) BESS – 1, 2, 4-, 8-hour storage options considered for lithium ion technology; 8 and 12-hour storage considered for vanadium redox flow battery technology PHES – 10-, 24-, 48- and 160-hour energy storage options considered
Project delivery	EPC turn-key basis
O&M approach	Thermal / hydrogen power generation: Owner operates and maintains, but contracts for scheduled maintenance

[11] Rawlinsons (2025) Rawlinsons Australian Construction Handbook
[12] It is noted that 500 kV networks are being expanded or implemented to support renewable energy zones and major projects and that large scale generation and storage will connect to these networks over time.

Item	Detail
	Renewables or storage: Owner appoints a third-party O&M provider

The assumed terminal points for the power generation or storage facility are described below. Communication links are considered to be common across technologies and have not been separately defined.

Table 2.2 Power generation / storage facility terminal points

No.	Terminal point	Terminal point location and details
1	Fuel supply (if relevant)	Gas: 30 – 40 bar supply pipeline at site boundary, dry and moisture free Coal: Train unloading facility located on site Diesel: Truck unloading facility located on site Biomass and waste: Truck unloading facility located on site
2	Grid connection	HV side of generator step-up transformer
3	Raw / potable water	Site boundary (Water treatment plant included in project scope if demineralised water required)
4	Wastewater	Site boundary
5	Road access	Site boundary
6	Hydrogen supply (if relevant)	Electrolyser: Outlet of package at delivery pressure (i.e. no additional compression)

2.3.3 Fuel connection / transport

The fuel connection scope and costs are highly dependent on both location and site. As such, a single estimate for each hypothetical project is not practical. An indicative $/km cost has been nominated based on prior work and publicly available data.

The natural gas fuel connection scope assumptions are as follows:

– Distance from connection point to power station: <50 km
– Pipeline size and class: DN200, Class 600 (AS 2885)
– Scope: hot tap at connection, buried pipeline to power station, and fuel conditioning skid
– Fuel conditioning skid plant and equipment: Filtration, heating, metering, pressure let down, etc (excludes any fuel compression).

The coal fuel connection scope assumptions are as follows:

– Coal transport via rail (i.e. power station not located at the mine mouth)
– Distance from starting point to power station between 50 to 100 km
– Single track rail line dedicated for power station use
– Scope: Track rail line from mine to power station location delivered under a D&C contract. Excluding loading infrastructure at mine.

The biomass and waste fuel connection scope assumptions are as follows:

– Biomass delivered to power station via road transport
– Existing road infrastructure used
– Unloading infrastructure included in power station cost
– No new transport infrastructure required hence no CAPEX associated with fuel supply (i.e. to be captured as an OPEX cost).

2.3.4 Natural gas compression and storage

Some natural gas power station projects require fuel gas compression depending on the pipeline pressure available and pressure requirements specified by the gas turbine manufacturer. A separate cost has been provided for natural gas compression where required.

The natural gas compression scope assumptions are as follows:

– Type: Reciprocating compressor
– Supply pressure: 30 bar. Discharge pressure: 50 bar.
– Capacity: ~50 t/h
– Scope: Complete supply of compressor(s) and enclosures. Includes civil works. Excluding power supply.

Natural gas storage facilities are also used for increased fuel security and supply chain / demand management. A cost has been provided on the following basis:

– Storage: Underground storage facility in a depleted natural gas field.
– Scope: Third party contract for storage at the Iona underground storage facility. (Note that this is the only underground facility which is currently provides storage services to third parties in the East Coast Gas Market.)

2.3.5 Hydrogen-based technologies and storage

2.3.5.1 Hydrogen production

Hydrogen is produced by two broad categories of technology:

– Electrolysis, where an electric potential is applied to electrodes in water which then breaks the water into hydrogen and oxygen, and
– Thermal decomposition of hydrocarbons, where heat and pressure is applied to hydrocarbons (e.g. natural gas) with steam which causes (ultimately) the breakdown to hydrogen and carbon dioxide.

In this Report, electrolysis and Steam Methane Reformation (SMR) have been considered.

PEM and alkaline electrolyser technology have been considered. Other electrolyser facility assumptions for the hypothetical project considered in this Report and associated costs are included in Section 4.4.

The assumption for the typical utilisation factor for larger electrolysers has been set as 70%. The eventual utilisation factor for any project will depend on the capacity of renewable energy (solar PV / wind) coupled to the electrolyser, or any additional grid power supply (from renewables or otherwise, either directly or via a power purchase agreement). To achieve 70% utilisation factor or higher would require an overbuild of renewable capacity compared to electrolyser capacity, and if no firming generation was available, additional energy storage would be required. Electrolyser utilisation factor depends on a number of factors such as power supply option (behind the meter or grid connection), hydrogen storage, and end user demand profiles. Power supply is a large component of the levelised cost of hydrogen in addition to electrolyser CAPEX. Hence, utilisation factor is project specific. Considering these factors, a typical optimised electrolyser utilisation factor could be around 70%, however, utilisation factors of up to 80-90% have been proposed for large scale developments.

2.3.5.2 Electrolyser facility, compression, storage and transport

When hydrogen is being produced from renewable sources considerable storage volumes are required to manage their intermittency, particularly where the end user requires a continuous supply or is being transported by road transport or sea going vessel.

The hydrogen compression scope assumptions for electrolyser-based hydrogen system are as follows:

– Type: Multi-stage reciprocating type
– Supply pressure: 30 bar (for PEM) or 1 bar (for Alkaline). Discharge pressure: 100 bar Capacity (each compressor): 2780 kg/h (3 x 33% duty, for 500MW plant total production rate)
– Scope: Complete supply of compressor(s) and enclosures. Includes civil works. Excluding power supply (assumed co-located with the electrolyser plant).

The hydrogen storage scope assumptions for electrolyser-based hydrogen system are as follows:

– Type: High pressure steel vessels (AS 1548 compliant)
– Pressure: 60 bar

– Size: 2,700 kg H_2 each (at 60 bar)
– Scope: Full supply and installation of storage tanks under D&C contract. Includes civils. Excludes additional compound infrastructure (assumes co-located with a wider facility).
– Other larger storage options at higher pressures may be available depending on storage volume requirements, however, these have not been considered in this Report for the purpose of the hypothetical project.

The hydrogen transport scope assumptions for electrolyser-based hydrogen system as follows:

– Type: Buried carbon steel pipeline (API 5L X42)
– Pressure: 100 bar
– Length: 50 to 250 km
– Diameter: DN150 (suitable for up to 100 MW electrolyser). Larger line size for 100 MW+ plant if proposed (cost not estimated)
– Scope: Full supply and installation of pipeline under D&C contract. Excludes compression and receiving stations at either end. Assumes single pipe run (not networked system).

2.3.5.3 Steam methane reforming facility, storage and transport

SMR facility costs are based on information from the International Energy Agency and other sources. The following points were considered in cost analysis for SMR/CCS:

– Site location: Close to natural gas supply point and consumer location
– SMR plant capacity: Approximately double the current largest in Australia, matching approximately the capacity of several large international plants
– Fuel quality: Australian Standards compliant natural gas
– Water quality: Raw water quality (typical of potable water)
– Hydrogen quality: 99.99% (refer to Table 2.1)

In addition to hydrogen production, hydrogen needs to be compressed (or liquified) and transported to the end user. The costs associated with compression (or liquification) and transport are considered separately in this Report.

Liquefaction, storage and pipeline costs are based on published recent studies. These studies generally report total system costs (e.g. compression and storage facilities combined) rather than component costs and, considering the nature of this Report, they are considered appropriate.

The costs for hydrogen storage are based upon either a liquefaction and cryogenic storage facility or underground storage. The liquefaction facility is based upon the upper end of a hydrogen liquefaction plants existing today. The largest existing is approximately 32tpd liquid H2[13]. As such a facility of 27tpd has been selected as a reasonable plant at the upper end of the existing sizes.

– Type: Cryogenic liquefaction and storage
– Temperature: Approximately - 252°C
– Capacity: 27tpd (liquefaction)

Costs for a hydrogen pipeline transmission and storage associated with using hydrogen produced from SMR with or without CCS or production from electrolysis are based on the assumption of a high pressure transmission pipeline with some storage in the system. The MAOP is set at 100 barg and pipeline material is Steel.

2.3.5.4 Hydrogen power generation

Hydrogen end users include power generation using reciprocating engines, turbines, and fuel cells with the following assumptions:

– 25% by volume hydrogen blend with natural gas reciprocating engine plant (current capability of selected OEM for plant size) with a 25% average capacity factor. Performance derate to be confirmed with OEM.

[13] Decker 2019- Latest Global Trend in Liquid Hydrogen Production

– 35% by volume hydrogen blend with natural gas using a smaller size aeroderivative DLN combustion system gas turbine (current capability) with a 20% average capacity factor. Performance derate to be confirmed with OEM.
– Large gas turbine using 5% hydrogen blend in natural gas supplied from gas network
– Small (<0.1 MW) and large scale (~1 MW) fuel cell of PEM technology type
– Additional NOx emission control (e.g. SCR) not included if required for hydrogen/gas turbines, potentially required for higher hydrogen blends than currently considered
– Other relevant key assumptions as defined in Table 2.1
– Relevant facility terminal points as defined in Table 2.2

2.3.6 Ammonia production facility

The ammonia production facility in this Report is based on the following assumptions:

– Ammonia synthesis using the Haber-Bosch process
– Nitrogen supply from air separation unit.

Other assumptions are as included in Section 4.9 for hypothetical project and associated cost assumptions.

2.3.7 Carbon capture and storage

CCS refers to the process of removing the CO2 from the flue gas / exhaust gas which is produced from traditional thermal power stations and typically released into the atmosphere. CCS can also be applied to blue hydrogen production by SMR. The most common form of CCS for power station is a post-combustion capture technology using a chemical absorption process with amines as the chemical solvent.

It has been assumed that in addition to the CCS chemical absorption and CO2 removal and compression process, a coal fired power station with CCS will also require selective catalytic reduction (SCR) for NOx removal and a flue-gas desulfurization (FGD) plant for sulphur dioxide (SOx) control. In Australia, depending on the coal quality and project location there may not be a specific requirement for the inclusion of SCR or FGD with a new coal-fired power station and as such these are not included in the non-CCS plant configuration. The post-combustion carbon capture absorption process typically has low NOx and SOx tolerances however and so these are included in the CCS plant configurations for coal-fired power station.

For the CCGT with CCS plant configurations it has been assumed that SCR and FGD processes would not be required due to the low sulphur content of Australia's natural gas and with the low NOx levels achievable with the latest gas turbine dry low NOx burner technology.

The downstream terminal point for the carbon capture process is assumed to be the outlet of the CO2 compression plant at nominally 150 bar (no temporary storage assumed on site).

CO2 transport costs are provided separately based on onshore transport via underground pipeline from the power station to the storage location. Costs are provided on a $/tCO2/km basis.

CO2 storage costs are provided separately and assumed to involve injecting the CO2 into a depleted natural gas reservoir. Costs are provided on a $/tCO2 basis.

CO2 capture rates of 90% and 50% have been considered.

2.3.8 Development and land costs

The development and land costs for a generation or storage project typically include the following components:

– Legal and technical advisory costs
– Financing and insurance (no interest during construction considered)
– Project administration, grid connection studies, and agreements
– Permits and licences, approvals (development, environmental, etc.)
– Land procurement and applications.

The costs for project and land procurement are highly variable and project specific. For the purposes of this Report and outlining development and land costs for a general project within each technology category, two options were adopted. Typically land and development costs are calculated as a percentage of capital equipment, and as a result, absolute values associated with these costs will change for those technologies whose equipment capital costs have changed. These costs do not include any applicable fees, such as fees paid to councils, local authorities, electrical connection fee etc. Where using the methodology based on percentage of capital equipment, the estimate has been determined based on recent projects, and experience with development processes. The alternative option to estimate land and development costs was the use of the methodology outlined in Section 8.1.4 which was used for technologies in Section 5 (hydropower).

Land costs can vary significantly depending upon its development potential (e.g. proximity to grid, environmental considerations, logistics considerations, location, etc.). These numbers are provided as a guide only. For some technologies (e.g. onshore wind), land can be leased instead of land procurement resulting in lower land cost.

2.3.9 Financial assumptions

The following key assumptions have been made regarding the cost estimates:

– Prices are based on real 2025 Australian dollars as outlined in Section 2.3.1, for financial close in July 2025. It is assumed the Contractor’s prices are fixed at this point for the execution of the project which may take several months or years depending upon the technology.
– New plant (no second-hand or refurbished equipment assumed, unless noted otherwise)
– Competitive tender process for the plant and equipment
– Taxes and import / custom duties excluded
– No interest during construction considered
– Assumes foreign exchange rates of 0.66 AUD = 1 USD
– No contingency applied
– No development premium considered

It is important to note that without specific engagement with potential OEMs and/or issuing a detailed EPC specification for tender, it is not possible to obtain a high accuracy estimate of costs, hence all costs are provided to a AACE Class 5 as outlined in Section 2.3.1. The risk and profit components of EPC contracts can vary considerably from project to project and are dependent upon factors such as:

– Project location
– Site complexity
– Cost of labour
– Cost of materials
– Market conditions
– Exchange rates

Where no project data or published cost trend data exists as applicable in the NEM region of Australia since the publication of the 2024 report[14], cost data has been escalated from the 2024 report[15] by applying a cost escalation rate as outlined in Section 2.3.1, with the exception of GT technologies where an escalation of 10% has been applied due to market conditions and supply chain issues. This escalation rate considers supply chain issues along with increased labour costs observed currently in the construction sector in Australia.

Costs for various technologies provided in this Report assumes that projects (except offshore wind projects) are located in the metropolitan areas in the National Electricity Market (NEM) region. For renewable projects that are located in renewable energy zones (REZ) rather than the metropolitan areas, a location cost factor needs to apply for equipment, installation, land and development and operation and maintenance.

[14] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)
[15] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)

No statistical analysis of available data was undertaken, rather an accuracy band was used. Cost of recent projects and publicly available information was used to arrive at this accuracy band. No prices from the market were obtained to analyse such data. However, the accuracy band is used to arrive at the cost of a project for certain size, scope of the project, year of completion, level of definition, and its battery limits. Costs vary due to several factors and for this reason this accuracy band is used. For the hypothetical project the cost falls within this target accuracy band.

2.3.10 Market volatility and construction cost uncertainties

The global construction industry is currently quite volatile, and it is difficult to predict the long-term inflationary impact on construction and operating costs. For industries using a high number of materials like stainless steel, copper and aluminium, the increase in capital costs for industrial equipment could be above 10%[16].

For the purposes of this estimate, the Report has factored in these considerations and market intelligence of specific industries, plant, and equipment wherever possible to derive a reasonable escalation amount from the 2024 costs.

In addition to typical construction materials, developers/owners should factor in considerable contingency for:

- Global competition for key components and technologies impacting wind turbine prices
- Contractor resourcing constraints and risk appetites increasing pricing in general
- Rising fuel and energy costs
- Labour shortages
- Geopolitical uncertainties impacting international supply chains

Construction cost growth adds a further element of uncertainty to new construction projects and maintenance activities, as well as inflationary pressures to the economy. With construction costs up more than 25% over the past five years[17], project proponents need to factor in considerable contingencies in addition to prices stated in this 2025 Report to allow for uncertainty and movement in construction costs, as well as for operating costs over the life of the project.

2.4 Definitions

The table below provides a high-level definition of key terms used in this Report. These are general definitions only. Refer to general assumptions above and technology specific assumptions throughout the Report for assumptions guiding the cost estimates provided in this Report.

Table 2.3 General definitions

Term	Definition
Development time	The period required to take the project from initial concept through to financial close. It encompasses stages of planning, permitting, financing, engineering, procurement, contract negotiations and offtake agreements etc.
EPC total programme	The period from which the EPC contractor receives Notice to Proceed through to Commercial Operation Date.
Total lead time	From receiving Notice to Proceed, the cumulative time required to source, manufacture, and deliver all equipment and materials to site, to the point where all components are ready for installation and construction.
Construction time	Following the total lead time, the point from which all equipment and materials have been received on site up to the Commercial Operation Date.
Economic life (Design life)	The estimated period during which the facility is expected to operate efficiently, safely, and economically under normal conditions, before major refurbishment, replacement, or decommissioning is required.

[16] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)
[17] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)

Term	Definition
Technical life (Operational life)	The technical life of an asset refers to the typical duration between the initial commercial operation of an asset and its final decommissioning, assuming standard operating conditions and major and minor maintenance or refurbishment / replacement.
Total EPC cost	Total cost of the EPC contract (excluding taxes).
Equipment cost	Cost of equipment and materials within the EPC contract. *Includes other EPC related costs such as engineering, overhead, risk, profit, etc. which is split evenly between Equipment cost and Installation cost.*
Installation cost	Cost of constructing, installing and commissioning works within the EPC contract. *Includes other EPC related costs such as engineering, overhead, risk, profit, etc. which is split evenly between Equipment cost and Installation cost.*
Carbon capture cost	This portion of the EPC contract specifically covers the supply, construction, installation, and commissioning of carbon capture systems and related equipment.
Total annual O&M cost	O&M costs are recurring expenses associated with the day-to-day functioning and upkeep of a power generation facility to maintain operations. Total annual O&M costs are the sum of fixed and variable annual O&M costs.
Fixed O&M costs	Fixed O&M costs are independent of energy output and include items such as routine maintenance, labour, and consultants / contractor costs.
Variable O&M costs	Variable O&M costs are proportional to the output of a power generation facility including consumables, scheduled term maintenance and long-term maintenance costs. Variable O&M are on a ‘sent-out’ or net basis.
Disposal Cost	Disposal costs refer to the offsite costs associated with disposal of materials produced through the decommissioning and demolition process, and through the act of rehabilitation (e.g. contaminated soil).
Recycling Costs	Recycling costs include potential savings associated with recycling or on sale of material or components that may be salvaged through the decommissioning process (e.g. steel, copper). This value can be used to offset the cost of retirement and contribute a negative cost. In certain circumstances, key components may be required to be recycled, yet recycling incurs a net cost (e.g. PV panels). Such elements will contribute a positive cost. Similarly, in some instances, key components may be sold or repurposed for another project and will contribute toward the retirement cost. The recycling estimates presented in each section of this Report are net recycling costs.
Retirement Cost	Retirement cost is the total cost incurred at the end of life of the asset in order to return the site to an assumed end state. This cost incorporates the cost of decommissioning, demolition, site rehabilitation, and disposal and recycling of materials.
Owner’s costs	Owner’s costs refer to the expenses required to maintain asset operations and incurred directly by the owner as part of business operations. In the context of this Report, Owner’s costs include but are not limited to: – Project planning and management – Land lease costs – Grid connection / utility interface costs – Financing and insurance costs – Corporate governance and business operations (i.e. Human resources, information technology, legal, etc) – Government fees, licences or permit fees, – Taxes and rates – These are highly specific to individual companies and assets.
Refurbishment	Replacing older components with new property, plant, or equipment to sustain business operations, maintain energy yield, reliability, and system capacity.
Decommissioning	Decommissioning of an asset is the planned, controlled process of permanently removing an asset from service, ensuring it is made safe, environmentally compliant, and prepared for demolition, repurposing, or site rehabilitation.

Term	Definition
Demolition	Demolition refers to the planned and controlled process of deconstructing or destroying physical structures of an asset in preparation for site rehabilitation, redevelopment or return to greenfield.
Rehabilitation	Rehabilitation is the process of restoring a site to a safe, stable, and environmentally compliant condition, consistent with regulatory and contractual requirements and the intended future land use of the site.
Minimum stable generation	This refers to the lowest percentage of a unit's rated gross capacity at which the generator can consistently operate over an extended period. It must maintain stability without needing extra fuel oil or similar assistance and be capable of reliably increasing output to full capacity while still meeting emissions licence requirements.
Maximum stable generation	This refers to the highest percentage of a unit's rated gross capacity at which the generator can consistently operate over an extended period.
Gross output	Total amount of electrical power produced by the generator before any deductions for internal consumption or losses. It represents the full capacity or production level of the generator over a given period.
Net output	The actual usable electrical power that is delivered to the grid or end users after subtracting internal consumption and losses (auxiliary load).
Auxiliary load	The electrical power consumed by the generator's own supporting systems to keep it running safely and efficiently. This load is not available for external use and is subtracted from the gross output to calculate the net output.
Planned maintenance	The scheduled, proactive servicing and inspection activities designed to ensure reliable operation, prevent unexpected failures, and extend equipment life.
Average planned maintenance downtime	The typical number of days per year offline due to scheduled maintenance activities.
Forced maintenance / outage	Unplanned shutdown or reduction in output due to a failure, malfunction, or safety issue that requires immediate attention
Equivalent forced outage rate	The percentage of time a unit is unexpectedly out of service (due to forced outages or forced deratings) relative to the time it was scheduled to be available.
Ramp up / down rate	The speed at which the unit can increase or decrease its power output, measured in megawatts per minute (MW/min).
Heat rate	The amount of energy input in gigajoules (GJ) needed to generate one kilowatt-hour (kWh) of electricity.
Efficiency	The ratio of useful electrical energy output to the total energy input. It measures how effectively the generator converts heat energy (usually from fuel combustion) into electrical power.
Energy consumption	The amount of energy required by the system to perform its intended function, such as generating electricity, storing energy, or powering a process (MWh/tonne).
Hydrogen consumption	The amount of hydrogen fuel used by a system (such as a fuel cell, hydrogen turbine, or hydrogen-powered generator) to produce a specific amount of energy output.
Water consumption	The amount of water used directly or indirectly during the operation of the system to produce energy.
Hydrogen production rate	The amount of hydrogen generated (kg of H_2 per day or kg of H_2 per hour) by a system such as an electrolyser, reformer, or other hydrogen-producing device.
Mass liquid H2 stored	The total quantity of hydrogen in its liquid form (tonnes) that is held within a storage system at a given time.
Annual ammonia output	Ammonia produced per year, tonnes per annum.
Battery storage: Charge efficiency	The percentage of electrical energy input during charging that is successfully stored in the battery and available for later use.
Battery storage: Discharge efficiency	The percentage of stored energy that can be successfully retrieved from a battery during the discharge process.
Battery storage: Allowable maximum state of charge (%)	The highest percentage of a battery's total capacity that can be safely charged to.

Term	Definition
Battery storage: Allowable minimum state of charge (%)	The lowest percentage of a battery's total capacity that can be safely discharged to.
Battery storage: Lifetime maximum number of cycles	The total number of complete charge - discharge cycles a battery can undergo in its lifetime.
Battery storage: Depth of discharge	The percentage of a battery's total capacity that can be discharged. It is the difference between the allowable maximum and minimum charges.
AACE Class 5 Estimate	The AACE Class 5 estimate commonly known as an "Order of Magnitude" estimate, represents the initial stage in the cost estimation continuum. A typical Class 5 estimate has an accuracy range as broad as -50% to +100%.

3. Generation technologies

3.1 Overview

The following sections outline the typical options, recent trends, technical parameters, and cost parameters for each of the nominated generation technologies. The information listed within the respective tables has been used to populate the CSIRO GenCost 2025 Excel spreadsheets in Appendix A.

Technologies within this section include:

1. Onshore wind
2. Offshore wind
3. Large-scale solar photovoltaic
4. Distribution-scale solar photovoltaic
5. Behind-the-meter photovoltaic
6. Ocean and wave
7. Concentrated solar thermal
8. Reciprocating engines
9. Coal fired power plants
10. Open cycle gas turbines
11. Combined cycle gas turbines
12. Bioenergy
13. Waste to energy

3.2 Onshore wind

3.2.1 Overview

Onshore wind energy is one of the most established and widely deployed renewable generation technologies worldwide, and it continues to play a central role in Australia's energy transition. Modern onshore wind turbines are typically three-bladed, horizontal-axis machines with blades positioned upwind of the nacelle. They are a proven technology with decades of operational experience, which has benefitted from continual improvements in performance and reliability.

Overall, onshore wind has matured into a highly bankable and cost-competitive generation option, supported by a deep global supply chain and growing operational experience in a variety of terrains and climates. Ongoing technology development is expected to further improve capacity factors, reduce costs, and enable deployment at sites closer to demand centres.

3.2.2 Typical options

Historically, commercial wind turbines have ranged from around 1 MW up to 6 MW, and more recent deployments and vendor roadmaps have pushed nameplate ratings into the 7-8 MW class. Hub heights for contemporary turbines commonly lie between 100-160 metres, with practical limits driven by available crane reach and transport logistics, while rotor diameters vary from the order of tens of metres for smaller platforms to 190-200 m for the largest rotors now being offered. Upscaling hub height increases the wind resources reached by the rotor, while upscaling rotor diameter increases the swept area and therefore the energy capture for a given wind regime. Both of these design levers raise capacity factors and can make lower-wind sites commercially viable; however, the extent to which a rotor can be enlarged on any given platform depends on structural load capacity, fatigue life, drivetrain and tower design, and what the OEM supplies as a certified configuration for the site-specific conditions.

Beyond turbine selection, a project's viability and scope are shaped by a mixture of site, regulatory and logistical factors. Secure land access and timely planning and environmental approvals are fundamental requirements, as is the availability of a suitable grid connection or transmission headroom. For construction, physical delivery constraints can materially constrain what turbine sizes and installation sequences are feasible, such as port facilities for import and laydown, road and bridge clearances for component transport, and the availability of heavy lift cranes and specialist contractors. Workforce and construction resource supply also influence programme risk and cost, and in constrained regions these non-technical limits can be the binding factor on a project's scale rather than the wind resource alone.

Typical onshore developments range from tens to 100+ turbines, with developers increasingly pursuing larger capacities to capture procurement, civil-works and connection economies of scale. Annual energy production and lifetime unit costs remain highly site-dependent because of local wind climate, micro-siting and turbine power curve matching, as well as exposure to curtailment. To respond to grid integration needs, a growing number of projects are being planned or delivered with co-located battery energy storage or other hybrid configurations to improve utilisation of connection capacity and to provide short-term firming services.

Different OEM platforms have distinct performance envelopes, availability profiles and logistical footprints, so matching a turbine model to the on-site resource, transport routes and O&M strategy is a key commercial decision. In practice, project teams must balance the marginal benefits of larger, higher-yielding units against supply-chain certainty, installation complexity and lifecycle operations costs to deliver a project that optimises energy yield, capital efficiency and delivery risk.

3.2.3 Recent trends

Onshore wind continues to evolve through a mixture of gradual technical improvement and sharp market-driven adjustments. Turbine towers have grown taller, rotors larger and nameplate capacity greater, as manufacturers are competing to lift annual energy production per MW and to make lower-wind sites economically viable. This technical upscaling is a deliberate response to limited remaining "top-tier" sites available in Australia and is now a defining feature of new project designs.

Recent industry trends have been defined by upscaling in unit nameplate capacity, enabled by taller hub heights and longer blades. Increases in rotor diameter expand the swept area (m^2), allowing more energy to be captured from a given wind resource up to the turbine's rated wind speed. This design evolution has not only increased energy yields but also unlocked more viable sites, including regions with lower average wind speeds that would previously have been considered uneconomic. Turbines are designed and manufactured to suit site-specific conditions such as mean wind speed, wind gusts and turbulence. Platforms can be optimised by increasing the ratio of the rotor diameter to the nameplate capacity for low-wind sites (annual average wind speeds at hub height around 6-7 m/s), or vice versa for high-wind sites (annual average wind speeds 8 m/s or higher).The suitability of larger rotors on a given turbine platform depends on factors such as mechanical loading, fatigue lifetime, and OEM product availability.

As the best, highest-wind sites in many mature markets have been developed or repowered, developers are increasingly turning to "second tier" locations and to repowering older sites. Repowering, which refers to replacing legacy machines with larger and more efficient units, is a near-term route to add capacity without expanding the project spatial footprint. Greenfield activity is shifting into areas where average wind speeds are lower or where siting and consenting complexity is higher. These dynamics mean new projects are more frequently judged on a combination of resource, grid access and consenting risk rather than raw wind class alone.

Lifetime extension (LTE) of onshore wind farms is often a sound economic alternative to full repowering or decommissioning because it can reuse existing site infrastructure (foundations, roads, grid connections) while deferring large capital outlay. Modern turbines were generally designed around a 20-year life, so a growing share of the early fleet in Australia are now at or beyond that design horizon – making LTE an increasingly important option for owners and policymakers.

Technically, an LTE assessment typically comprises two complementary parts: (1) a practical inspection programme (tower, foundation, blades, hubs, nacelle internals, bolted joints, etc.) and (2) an analytical reassessment (SCADA/operational data analysis, load and fatigue re-calculation, material testing and non-destructive examination). Condition monitoring and SCADA analytics help detect developing faults early, and interventions range from targeted repairs (blade surface repairs, bearing/gearbox overhauls) and control-system updates to full component replacements or partial repowering. Certification and verification by third parties is required to demonstrate acceptability to financiers and regulators, while the final commercial decision balances remaining fatigue life, cost of major replacements, spare parts and OEM support, and site planning/land-rights requirements. Depending on the site and scope, operators commonly seek incremental extensions (typical studies and projects consider horizons in the order of 5–15 years), but the optimal path is highly site- and fleet-specific.

The last three years have also seen cost increases that have materially affected onshore wind project economics. Commodity and logistics pressures disrupted supply chains during and after the COVID-19 pandemic, and broader inflationary and financing headwinds pushed turbine and balance-of-plant prices upward in many regions. In parallel, practical responses to these pressures are shaping project design and contracting. Developers and OEMs are adopting modular transport and tower concepts (including concrete-steel hybrid towers) to circumvent transport and crane limits, and hybrid project designs that pair wind with batteries or other flexibility-providing assets are gaining traction to increase value from constrained grid connections. On the electrical side, full-power converters and grid-forming inverter controls are being explored and deployed to help wind plants perform in weaker, low-inertia systems. An example is the 69 MW Dersalloch wind farm in Scotland, which was trialled in grid-forming mode for six weeks during 2019, by adjusting inertia coefficients in its control system, with minor impact to overall cost. In Australia, the Golden Plains wind farm utilises Vestas turbines with a full-scale inverter[18]. Commercially, the market is seeing more varied contract structures, longer offtake arrangements and innovative financing solutions as participants seek to allocate risk more explicitly and to preserve bankability in a higher-cost environment. On the civil side, precast concrete foundations offer a promising alternative to traditional cast-in-site solutions for onshore wind turbines, providing faster installation, improved quality control, and reduced weather-related delays. Their modular design supports repeatable fabrication in controlled factory conditions, with potential for enhanced safety and sustainability through reduced site work and material waste. The reduced site work means a shorter installation time and reduced amount of concrete needed, as was shown in a demonstration project at Palmers Creek Wind Farm in the USA, where precast spread footing was used at 18 turbines[19]. Self-erecting turbines are another potential innovative construction solution, offering an alternative to utilising heavy cranes. A prominent example is Nabralift, which has prototypes installed in Spain, Morocco and France. It uses a Self-Erection System and a lattice style structure supported by a three-column structure, requiring less concrete[20].

Taken together, these trends point to an industry that is technically mature but commercially recalibrating: the simple productivity gains from larger machines and higher towers continue to open up otherwise marginal sites, yet developers must now manage tighter supply chains, higher CAPEX risk and a growing emphasis on repowering, co-location and grid-compatibility measures to deliver competitive, bankable projects.

3.2.3.1 Summary of changes

Compared to 2024 estimates, there was an increase in onshore wind turbine capacity from 6.2 MW to 7.2 MW to reflect the recent developments in industry, with increasing turbine sizes. A learning from onshore wind projects being developed in Australia over the last 12 months is that the 7.2 MW turbine size is more commonly seen than 6.2 MW. An example of this is the Vestas V172-7.2 MW wind turbine which was announced in a press release in 2022.

Due to this increase in turbine size requiring more civil works, as well as more complex terrain and lengthened grid connection construction, the assumption around construction time has been increased from 90 weeks in the 2024 report to 130 weeks in this report.

[18] **https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2021/application-of-advanced-grid-scale-inverters-in-the-nem.pdf**
[19] **Palmers Creek Wind Project | Sargent & Lundy**
[20] **https://www.nabrawind.com/our-solutions/nabralift/**

3.2.4 Selected hypothetical project

Table 3.1 Configuration and performance – Onshore wind

Item	Unit	Value	Comment
Configuration			
Technology / OEM	-	Vestas	Other options include GE, Goldwind, Nordex, Siemens Gamesa, Envision
Make model	-	V162-7.2	Recent market development has seen increasingly higher capacity generators in onshore wind projects in Australia. 7 or 7.2 MW is a typical size for a project under development in 2025.
Unit size (Nominal)	MW AC	7.2	Nameplate capacity
Number of units	-	100	Wind farms are generally increasing in size, although a wind farm of this size will possibly be built in two or more stages. The cost assumptions presented here have assumed one stage due to the possibility of one stage.
Performance			
Total plant size (Gross)	MW AC	720	This is a large connection on the NEM, and capacity may be restricted depending on connection location.
Auxiliary power consumption and losses	%	3%	Electrical losses from turbines, cables and substation.
Total plant size (Net)	MW AC	698.4	
Seasonal rating – Summer (Net)	MW AC	698.4	High temperature derating occurs above 20°C at low altitudes, with more derating applicable for higher altitudes. These effects are temporary and accounted for in site-specific energy yield analysis.
Seasonal rating – Not Summer (Net)	MW AC	698.4	Generation is reduced at higher wind speeds, which occur more frequently outside summer months. Generation also scales linearly with air density, with denser air in the winter months. These effects are temporary and accounted for in site-specific energy yield analysis.
Annual Performance			
Average planned maintenance	Days / year	-	Included in equivalent forced outage rate below
Equivalent forced outage rate	%	2.5%	Contractual availability for wind turbines is typically 97.5% for the first 20 years of operation, reducing after that.
Effective annual capacity factor	%	35%	Taken from International Renewable Energy Agency (IRENA) weighted average capacity factor for Australia for 2024. This is a slight reduction from 36% in 2023, mainly due to an increasing share of the top tier wind resource sites being taken.
Annual generation	MWh	2,090,000	
Annual degradation over design life	% pa	0.1%	A simplified linear degradation applicable to annual energy generation.

Table 3.2 Technical parameters and project timeline – Onshore wind

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	Resource dependent	-
Ramp down rate	MW / min	Resource dependent	-
Start-up time	Min	N/A	-
Min stable generation	% of installed capacity	Near 0	At cut-in wind speed (typically around 3m/s)

Item	Unit	Value	Comment
Project timeline			
Time for development	Years	4-6	Includes site investigations, design, procurement and approvals. Approvals and consents may include environmental monitoring and may take roughly 2 years. Wind measurements to capture seasonal trends are typically done for at least 12 months, which requires installation of a met mast. If the approvals and measurements exist, the development time may be shorter than 4 years.
First year assumed commercially viable for construction	Year	2025	-
EPC programme	Years	3	From NTP to COD
– Total lead time	Years	1	From NTP to first turbine delivered to site
– Construction time	Weeks	130	Approximately 8-10 days per turbine installation is typical.
Economic life (Design life)	Years	25	Industry benchmark although OEMS vary between 20-25.
Technical life (Operational life)	Years	25	Industry benchmark although may increase with lifetime extension to 30-35 or greater with repowering.

3.2.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined onshore wind project.

Table 3.3 Development cost estimates – Onshore wind

Item	Unit	Value	Comment
CAPEX construction			
Relative cost	$/kW (Net)	3,150	Based on GHD internal benchmark. Increase in costs in recent years due to supply chain impacts and financial parameters.
Total cost	$	2,213,900,000	Of which roughly 2 thirds are typically turbine supply and installation and one third is balance of plant supply and installation.
– Equipment cost	$	1,549,000,000	Based on GHD internal benchmark ratio of 70% of CAPEX for equipment costs
– Installation cost	$	663,900,000	Based on GHD internal benchmark ratio of 30% of CAPEX for installation costs
Cost of land and development	$	55,325,000	Based on GHD internal benchmark of 2.5% of total CAPEX. Of which 0.5% is land, and 2% is DEVEX.

3.2.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined onshore wind project.

Table 3.4 O&M cost estimates – Onshore wind

Item	Unit	Value	Comment
Fixed O&M cost	$/MW/year (Net)	29,000	Based on internal GHD benchmark. Note that wind turbine O&M contract is roughly one third of the overall operating cost. Other sources of OPEX are significant such as insurance, land leasing, grid connection annuity charges, and BOP maintenance.
Variable O&M cost	$/MWh (Net)	-	Included in Fixed component
Total annual O&M cost	$	20,253,600	-

3.2.7 Retirement cost estimates

Retirement costs for the defined onshore wind project are outlined in the table below.

The same assumptions were used as for GHD's 2025 Energy Technology Retirement Cost & O&M Estimate Review – refer to Appendix C. Although the assumed nameplate capacity was increased from 6.2 to 7.2 MW, any changes to retirement cost estimates are captured by the $/MW values.

Table 3.5 Retirement cost estimates – Onshore wind

Item	Unit	Value
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	181,000
Disposal costs	$/MW (Net)	4,500
Recycling costs	$/MW (Net)	(24,500)
Total retirement costs	$/MW (Net)	161,000

3.3 Offshore wind

3.3.1 Overview

The global offshore wind sector has expanded rapidly in recent years, driven by innovation and advances in turbine technology, foundations, and project delivery models. These improvements have reduced costs in mature markets and made offshore wind a more competitive option for large-scale renewable generation located close to demand centres. In Australia, the industry is still at an early stage but is attracting significant state and federal policy support and has attracted strong interest from experienced international developers.

One of the defining characteristics of offshore wind is its scale: projects are commonly developed at capacities exceeding 1 GW, with multi-stage build-outs designed to reduce unit costs and support high-capacity export connections. Offshore sites also benefit from higher quality wind resources than typical onshore locations. Wind speeds are generally stronger, less turbulent, and display diurnal profiles that complement solar PV and onshore wind generation, with offshore wind often providing higher output during late afternoon and evening periods. These characteristics make offshore wind particularly attractive for system diversity.

The proximity of many prospective offshore wind zones to major coastal load centres offers the potential to reduce reliance on long-distance overland transmission. In the Australian context, this is especially relevant where proposed zones align with regions in which coal-fired generation is scheduled to retire. Offshore wind could take advantage of existing transmission corridors, substations, and skilled workforces in these areas, supporting the energy transition. Offshore sites also allow the deployment of larger turbines and arrays than are typically possible onshore. Current commercial machines exceed 15 MW in capacity, with towers above 150 metres and rotor diameters greater than 250 metres, enabling higher capacity factors and fewer foundations per megawatt. These turbines are specifically engineered for marine environments, with blades, drivetrains, and towers designed to withstand corrosion and fatigue.

Project delivery for offshore wind is more complex and capital-intensive than for onshore projects. Construction requires specialist vessels, significant port infrastructure, and safe weather windows. Operation and maintenance is also more challenging offshore, requiring marine access, safety compliance, and service vessels. Internationally, the sector has also been affected by inflation, interest rates, and supply chain bottlenecks of critical elements such as substation infrastructure and installation vessels.

In the Australian context, prospective zones vary in water depth and distance from shore, meaning both fixed-bottom and floating foundation technologies are likely to be relevant. Floating platforms, which are increasingly being demonstrated in Europe, may be particularly important for deeper waters near population centres. Deliverability in Australia will depend heavily on reduction of capital expenditure of floating wind turbines, as well as timely investment in ports and assembly areas, securing appropriate installation vessels, and developing a skilled domestic workforce.

For the purpose of this Report, international average cost benchmarks from recognised intergovernmental agencies have been adopted. Apart from a cost premium to reflect the transport of the turbines and other balance of plant to Australia, no specific Australian regional cost uplift has been applied, as no project has yet achieved financial close in Australia. As the industry matures, and as domestic supply chains, infrastructure, and regulatory processes are further established, the cost outlook for offshore wind in Australia will become clearer.

3.3.2 Typical options

Offshore wind farm projects cover a broad range of turbine ratings and balance of plant design choices. In the last 25 years, commercially deployed turbines have increased in size from 2 MW nameplate capacity and 80m rotor diameter to 15 MW nameplate capacity and 240m rotor diameter. In 2024, the average rating of installed offshore turbines in Europe was 10.1 MW, while the average rating of ordered turbines was 14.8 MW. Developers may pursue either fewer large turbines or many smaller machines depending on site and supply-chain considerations, but the prevailing industry direction is toward larger rotors and higher nameplate ratings because upsizing tends to increase capacity factors and reduce balance-of-plant cost per MW through economies of scale. Turbine OEMs and some market participants have, however, signalled caution about indefinite up-scaling due to supply-chain, installation and reliability trade-offs, and several manufacturers have adjusted their product roadmaps in response to those constraints, to focus on standardisation and quality of existing turbine models.

The total installed capacity of a project materially affects its unit economics and system design choices. Larger wind farms can capture logistics and learning benefits, but they also require appropriately sized electrical collection and export systems. Offshore substations are commonly sized in the 300-500 MW range, and many modern developments organise generation around multiples of these platform capacities so that 400 MW (or similar) topside ratings per platform are frequently seen in practice. This clustering into substation-sized blocks influences the preferred project build-out (single large export vs multiple 400 MW platforms) and is a direct factor in choices about export voltage, the number of export cables, and onshore reinforcement requirements. Export cables are usually rated at 220 kV for commercial scale projects (400MW+), while array cables are typically 66 kV although this may increase to 132 kV in coming years. For large projects (1GW+) that are far from shore (80km+), High Voltage Direct Current (HVDC) is an option to significantly reduce electrical losses in the export cable and to reduce the need for reactive power compensation. HVDC export cables have been used recently in projects in northern Europe, however the infrastructure is expensive and has a long lead time, and in some cases developers have chosen to instead use HVAC together with Reactive Power Compensation Stations. An example of HVDC infrastructure is the Dogger Bank A HVDC offshore Platform, which collects 1.2 GW of AC power, converts it to DC, and transports it approximately 150km to the onshore connection point. To the south of Dogger Bank is the Hornsea 1 offshore wind farm (also 1.2GW and roughly 120km from shore), which installed a Reactive Compensation Station to compensate the reactive power.

The choice and design of turbine foundation and substructure is another design choice. The dominant type of foundation, with about 80% of the fixed offshore wind capacity, is installed on monopiles driven into the sea bed, with jacket foundations representing 15%, and the remaining being gravity base foundations. Monopiles are essentially a singular steel tube, which is easier to manufacture and install than jackets. They usually have a transition piece between the monopile and turbine tower. Jacket foundations are usually secured to the sea bed using pin piles, but suction buckets are another option. The design choice of foundation depends on the water depth, ground conditions, wind and metocean conditions, turbine model, supply chain and manufacturing constraints. Monopiles have been installed up to around 50 metres water depth while the deepest jacket installed was at a water depth of 58.6m at Seagreen offshore wind farm in the UK. For deeper waters, floating foundations (spar, semi-submersible, tension-leg, barge and other hybrid platforms) become the economically practical option. Floating concepts are now progressing through demonstration and early commercial projects in Europe and are expected to become increasingly relevant for Australian sites with deeper near-coast bathymetry.

Offshore layouts and electrical architectures offer planners more geometric freedom than onshore sites, enabling micro-siting that intentionally spaces turbines to reduce wake losses and optimise array production while balancing cable length and seabed constraints. Wake modelling and layout-optimisation tools are commonly used during design to trade greater spacing (and reduced wake losses) against increases in array cable length and foundation count; this optimisation is a specific lever for improving annual energy production and project economics offshore.

Similarly, inter-array cable topology and conductor material are design choices: array layouts may use stringed, radial or tree topologies (and combinations thereof) to minimise cable cost and fault exposure and to simplify installation and repair, and array cables may be designed with copper or aluminium cores depending on weight, cost, conductivity and handling considerations. Copper offers higher conductivity and favourable fatigue characteristics but is heavier and more expensive, whereas aluminium is lighter and typically cheaper but requires larger cross-sections and careful termination practice, and it can be preferred where weight and vessel handling are limiting factors. For floating concepts dynamic cable systems add further technical constraints that influence conductor choice and routing.

These technical options interact with deliverability considerations, e.g. installation relies on specialised vessels, port and marshalling capacity, and suitably experienced supply chains, while operations and maintenance strategy (and access windows) are shaped by chosen foundation, turbine size and array architecture. Decision makers should therefore evaluate turbine sizing, platform count and substation partitioning (for example planning in multiples of a practical substation rating such as ~400 MW), foundation selection by depth, array and cable topology, and conductor material in an integrated way so trade-offs between capital cost, annual energy production (AEP), reliability, O&M cost and schedule risk are explicit in any project feasibility or planning study.

In offshore wind, technical lifetime extension (LTE) involves engineering and operational measures designed to safely prolong a wind farm’s useful service beyond its original design life (often about 20-25 years). To do this, key structural and mechanical systems must be evaluated and upgraded as necessary. Refurbishments may include reinforcing or repairing support structures (monopiles, jackets, foundations) to handle fatigue and corrosion, replacing or overhauling mechanical components (gearboxes, bearings, pitch/yaw systems), upgrading blades (erosion protection, leading edge repairs), improving corrosion protection and coatings, enhancing control systems and condition monitoring (e.g. sensors, SCADA enhancements), and ensuring that electrical systems (subsea cables, transformers, export cables) remain fit for continued operation under harsher cumulative load. Environmental loading (wave, wind, salt spray), fatigue damage, material degradation (metal fatigue, corrosion, weld deterioration) all need to be assessed through inspection, non-destructive testing, and possibly material sampling or lab testing to decide what refurbishments are required to safely push life out further. One example is Horns Rev 1 in Denmark, which at over 20 years old, is one of the first large-scale offshore wind farms. It has adapted lifetime extension measures, as e.g. operators are implementing preventative maintenance contracts, condition monitoring, and retrofitting smart technologies to monitor turbine performance more closely. In 2025, the Danish Energy Agency approved three Danish offshore wind farms to extend their operational lifetimes to 32, 49 and 33 years respectively for Nysted, Middelgrunden, and Samso Offshore Wind Farms.

3.3.3 Recent trends

The offshore wind industry has continued to expand rapidly but with notable recent volatility. Global operational capacity rose to roughly 83 GW by the end of 2024, with annual additions concentrated in a handful of markets. Growth remains geographically concentrated, with China now accounting for a very large share of operational and newly commissioned capacity and driving a significant portion of near-term pipeline activity. Over the past decade the industry realised substantial cost and performance improvements – greater deployment, larger rotors and higher capacity factors, and supply-chain learning drove down typical unit costs and Levelised Cost of Energy (LCOE) – but those long-run gains have been partially offset since 2021 by higher inflation and interest rates, commodity and shipping price increases, vessel and component scarcity, and higher financing costs, producing material project repricing and some contract cancellations or project delays in 2022-2024.

Manufacturers and developers have reacted by re-balancing product roadmaps, and in some cases pausing, deferring or terminating projects where economics have deteriorated. Meanwhile, technological advancement continues across the sector. Turbine ratings are increasing with Siemens Gamesa reportedly installing a 21.5 MW prototype at a test centre in Denmark in 2025. Monopiles and jacket foundations are able to reach ever deeper waters, while at the same time, floating foundations have advanced from demonstration to early commercial roll-out – opening deeper waters and new siting options. Both fixed-bottom and floating pathways are expected to see cost declines as volume builds but floating wind remains at an earlier stage of commercial maturity. At the project-level, developers are continuing to aggregate scale because larger wind farms and multi-GW build-outs capture logistics, fabrication and installation economies and improve unit economics.

Chinese offshore wind turbine manufacturers such as MingYang are increasingly seeking to expand beyond their domestic market, motivated by both the saturation of near-shore opportunities in China and the desire to capture a share of the growing international pipeline. With a track record of rapid deployment at scale and competitive pricing, Chinese OEMs have demonstrated the ability to deliver high-volume, cost-effective turbines domestically, but their entry into non-Chinese markets has so far been limited by factors such as certification standards, supply chain localisation requirements, political sensitivities, and concerns around after-sales support. Nonetheless, several Chinese manufacturers are now pursuing type certification aligned with international standards, establishing partnerships with global developers, and signalling intent to supply projects in Europe, Southeast Asia, and potentially Australia. The extent to which they succeed will depend not only on cost competitiveness but also on their ability to demonstrate long-term reliability, meet local content expectations, and build trust in markets that have historically relied on European OEMs. Another geopolitical reality is the series of stop orders in the US market, which have had detrimental effects on projects like Sunrise Wind, Empire Wind and Revolution Wind. The latter of these was issued a stop-work order by the US Department of Interior when the construction of the project was 80% complete.

For Australia these global trends translate into opportunity and caution: the proximity of declared offshore zones to major coastal load centres and to regions where coal is being retired creates strong system value potential, but the local market remains nascent so first-of-a-kind projects will likely face higher regional premiums for vessels, port upgrades, local workforce development and supply-chain establishment until a domestic delivery ecosystem matures. One unique opportunity for Australia is that, due to being one of the only offshore wind markets in the southern hemisphere, installation windows for the Australian summer may open up availability of crucial turbine and foundation installation vessels, which are often constrained. Some Australian jurisdictions are already moving to coordinate and fund shared transmission and port readiness to reduce that uplift. Overall, the recent trend can be summarised as continued technological progress and scale-up tempered by a multi-year period of cost pressure and market re-calibration. The path forward will depend on how quickly supply chains, financing conditions and policy settings adapt to restore the learning-by-doing trajectory that delivered offshore cost reductions earlier this decade.

3.3.3.1 Summary of changes

Compared to 2024 estimates there was a 21% increase in relative cost of CAPEX for offshore wind. This is mainly due to impacts on installation and equipment cost from inflation and supply chain constraints experienced over the last 2-3 years, and as such, the costs within this Report have been recalibrated based on current information.

There was also an increase in offshore wind turbine capacity from 12 MW to 15 MW to reflect the recent developments in industry, with increasing turbine sizes. The Vestas V236-15 MW has been a popular turbine commissioned and installed in 2025 in markets such as Germany and Taiwan, and it is likely that offshore wind turbines installed in Australia, by the time of the first Australian offshore wind projects, will be at least 15 MW capacity and 236m rotor diameter. Thus, this turbine was used as a selected hypothetical project. The assumed gross total plant size (1200 MW) has remained the same between 2024 and 2025.

Energy calculation was completed using Net MW AC plant size, and accounting for Equivalent Forced Outage Rate. These two aspects of the calculation were different to the 2024 report which contributes to the difference in energy generation calculated between the 2024 report (5,150,880 MWh / year) and the 2025 report (4,800,000 MWh / year).

3.3.4 Selected hypothetical fixed foundation project

Table 3.6 Configuration and performance – Offshore wind (Fixed foundation)

Item	Unit	Value	Comment
Configuration			
Technology / OEM	-	Vestas	Other options include GE, Siemens Gamesa, MingYang, Goldwind
Make model	-	V236-15 MW	-
Unit size (Nominal)	MW AC	15	The average power ratings for offshore turbine orders in 2024 was 14.8MW. It is not expected that offshore turbines in Australia will be smaller than 15MW.
Number of units	-	80	-
Site condition	m	Water depth: 30m	Realistic for monopile foundations
	km	Distance to shore: 50km	Fixed bottom projects have been installed up to 150km from shore
Performance			
Total plant size (Gross)	MW AC	1200	This is a large connection on the NEM, and capacity may be restricted depending on connection location
Auxiliary power consumption and losses	%	4%	Slightly larger electrical efficiency losses than onshore wind due to typically longer AC export cable
Total plant size (Net)	MW AC	1152	-
Seasonal rating – Summer (Net)	MW AC	1152	Generation is reduced at higher wind speeds, which occur more frequently outside summer months. Generation also scales linearly with air density, with denser air in the winter months. These effects are temporary and accounted for in site-specific energy yield analysis.
Seasonal rating – Not Summer (Net)	MW AC	1152	Generation is reduced at higher wind speeds, which occur more frequently outside summer months. Generation also scales linearly with air density, with denser air in the winter months. These effects are temporary and accounted for in site-specific energy yield analysis.
Annual Performance			
Average planned maintenance	Days / year	-	Included in EFOR below
Equivalent forced outage rate	%	5%	Contractual availability for wind turbines is typically 95% for the first 20 years of operation, reducing after that.
Effective annual capacity factor	%	50%	Anticipated capacity factor for offshore wind farms in Europe is about 50%.
Annual generation	MWh / year	4,800,000	Net
Annual degradation over design life	%	0.1%	A simplified linear degradation applicable to annual energy generation.

Table 3.7 Technical parameters and project timeline – Offshore wind (Fixed foundation)

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	Resource dependent	-
Ramp down rate	MW / min	Resource dependent	-
Start-up time	Min	N/A	-

Item	Unit	Value	Comment
Min stable generation	% of installed capacity	Near 0	At cut-in wind speed (typically around 3m/s)
Project timeline			
Time for development	Years	5+ years	The timeline depends on regulatory framework and market maturity. According to [21], the development process from first consideration of a site to FID typically takes between four and seven years in the UK, but it is likely this will take longer in new markets such as Australia. Site and environmental monitoring take 2 years to capture seasonal trends. These feed into detailed design and procurement timelines, which can each take 12+ months. In new markets this can be longer, due to enabling infrastructure like ports and transmission, as well as all the regulatory framework development.
First year assumed commercially viable for construction	Year	2032	Updated to reflect the first year commercially viable in the first offshore wind auction in Australia.
EPC programme	Years	6 years	-
– Total lead time	Years	3 years	Includes long lead time, finalisation of procurement, manufacturing and transport of equipment.
– Construction time	Years	3 years	Installation of foundations and turbines relies on weather windows of calm weather.
Economic life (Design life)	Years	25	Industry benchmark.
Technical life (Operational life)	Years	30	Industry benchmark although may increase with lifetime extension to 35 or greater with repowering.

3.3.5 Development cost estimates – Fixed foundation

The following table provides CAPEX cost estimates for the defined fixed foundation offshore wind project.

Table 3.8 Development cost estimates – Fixed foundation

Item	Unit	Value	Comment
Relative cost	$/kW (Net)	5,216	Based on international benchmark and including a 2% premium for Australian market to account for transport costs. Note that CAPEX in offshore wind has increased globally since 2023[22].
Total cost	$	6,259,200,000	-
– Equipment cost	$	4,068,480,000	Based on international benchmarks of roughly 65% of CAPEX being equipment costs[21]
– Installation cost	$	1,877,760,000	Based on international benchmarks of roughly 30% of CAPEX being installation costs [21]
– Development and Project Management	$	312,960,000	Based on international benchmarks of roughly 5% of CAPEX being development costs [21]
Fuel connection costs	$	N/A	

[21] ORE Catapult, **Wind farm costs | Guide to an offshore wind farm**
[22] ORE Catapult, **https://ore.catapult.org.uk/resource-hub/blog/allocation-round-6-results-and-analysis,** accessed September 2025.

3.3.6 O&M cost estimates – Fixed foundation

The following table provides fixed, variable and total annual O&M cost estimates for the defined fixed foundation offshore wind project.

Table 3.9 O&M cost estimates – Fixed foundation

Item	Unit	Value	Comment
Fixed O&M cost	$/MW/year (Net)	175,000	Based on international benchmarks[21]
Variable O&M cost	$/MWh (Net)	-	Included in fixed component
Total annual O&M cost	$	210,000,000	International benchmarks have been updated in 2025 to reflect current industry trends and development.

3.3.7 Retirement cost estimates – Fixed foundation

Retirement costs for the defined fixed foundation offshore wind project are outlined in the table below.

The same retirement assumptions were used as for the 2025 Energy Technology Retirement Cost & O&M Estimate Review[23] – refer to Appendix C.

Table 3.10 Retirement cost estimate – Fixed foundation

Item	Unit	Value
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	650,000
Disposal costs	$/MW (Net)	3,000
Recycling costs	$/MW (Net)	(96,000)
Total retirement costs	$/MW (Net)	557,000

3.3.8 Selected hypothetical floating foundation project

Table 3.11 Configuration and performance – Offshore wind (Floating foundation)

Item	Unit	Value	Comment
Configuration			
Technology / OEM	-	Vestas	Other options include GE, Siemens Gamesa, MingYang, Goldwind
Make model	-	V236-15	-
Unit size (Nominal)	MW AC	15	The average power ratings for offshore turbine orders in Europe in 2024 was 14.8MW. It is not expected that offshore turbines in Australia will be smaller than 15MW.
Number of units	-	29	-
Site condition	m	Water depth: 100m.	Water depths of 100m are beyond current industry standards for fixed-bottom foundations.
	km	Distance to shoreline: 60km	-
Performance			
Total plant size (Gross)	MW AC	435	-
Auxiliary power consumption and losses	%	4%	Slightly larger electrical efficiency losses than onshore wind due to typically longer AC export cable

[23] AEMO, 2025 Energy Technology Retirement Cost & O&M Estimate Review, 2025

Item	Unit	Value	Comment
Total plant size (Net)	MW AC	418	-
Seasonal rating – Summer (Net)	MW AC	418	Generation is reduced at higher wind speeds, which occur more frequently outside summer months. Generation also scales linearly with air density, with denser air in the winter months. These effects are temporary and accounted for in site-specific energy yield analysis.
Seasonal rating – Not Summer (Net)	MW AC	418	Generation is reduced at higher wind speeds, which occur more frequently outside summer months. Generation also scales linearly with air density, with denser air in the winter months. These effects are temporary and accounted for in site-specific energy yield analysis.
Annual Performance			
Average planned maintenance	Days / year	-	Included in EFOR below
Equivalent forced outage rate	%	5%	Contractual availability for wind turbines is typically 95% for the first 20 years of operation, reducing after that.
Effective annual capacity factor	%	50%	Operational floating offshore wind farms have demonstrated high capacity factors.
Annual generation	MWh / year	1,750,000	-
Annual degradation over design life	%	0.1%	A simplified linear degradation applicable to annual energy generation.

Table 3.12 Technical parameters and project timeline – Offshore wind (Floating foundation)

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	Resource dependent	-
Ramp down rate	MW / min	Resource dependent	-
Start-up time	Min	N/A	-
Min stable generation	% of installed capacity	Near 0	-
Project timeline			
Time for development	Years	5+ years	The timeline depends on regulatory framework and market maturity. Site and environmental monitoring take 2 years to capture seasonal trends. These feed into detailed design and procurement timelines, which can each take 12+ months. In new markets this can be longer, due to enabling infrastructure like ports and transmission, as well as all the regulatory framework development.
First year assumed commercially viable for construction	Year	2035	Assumed at least 3 years after fixed-bottom in the Australian market
EPC programme	Years	6 years	-
– Total lead time	Years	3 years	Includes long lead time, finalisation of procurement, manufacturing and transport of equipment.
– Construction time	Years	3 years	Installation of floating wind turbines (including transport to site and mooring) requires calm weather.

Item	Unit	Value	Comment
Economic life (Design life)	Years	25	Industry benchmark.
Technical life (Operational life)	Years	30	Although no floating wind farm has operated this long, it is assumed to be the same as for fixed bottom for operational life.

3.3.9 Development cost estimates - Floating foundation

The following table provides CAPEX cost estimates for the defined floating foundation offshore wind project.

Table 3.13 Development cost estimates – Floating foundation

Item	Unit	Value	Comment
CAPEX			
Relative cost	$/kW (Net)	8,000	Based on GHD's internal benchmark for fixed bottom offshore wind, with a ratio of floating to fixed based on ORE Catapult
Total CAPEX cost	$	3,480,000,000	-
– Equipment cost	$	2,436,000,000	Based on international benchmarks of roughly 70% of CAPEX being equipment costs. Note the current CAPEX estimations for floating foundations are approximately twice that of fixed foundations.
– Installation cost	$	939,600,000	Based on international benchmarks of roughly 27% of CAPEX being installation costs
– Development and Project Management	$	104,400,000	Breakdown based on ORE Catapult[24]
Fuel connection costs	$	N/A	Not applicable

3.3.10 O&M cost estimates – Floating foundation

The following table provides fixed, variable and total annual O&M cost estimates for the defined floating foundation offshore wind project.

Table 3.14 O&M cost estimates – Floating foundation

Item	Unit	Value	Comment
Fixed O&M cost	$/MW/year (Net)	201,765	Based on GHD's internal benchmark for fixed bottom offshore wind, with a ratio of floating to fixed based on ORE Catapult
Variable O&M cost	$/MWh (Net)	-	Included in fixed O&M
Total annual O&M cost	$	87,767,775	-

3.3.11 Retirement cost estimates – Floating foundation

Retirement cost for the 435 MW floating offshore wind farm contemplated in the retirement scenario is estimated at $182,000 per MW. The retirement costs are the total costs net of any salvage value. Disposal costs and recycling benefit are the cost for disposing material and salvage value from recycling material respectively and are included in the overall retirement cost.

Retirement costs for the defined floating foundation offshore wind project are outlined in the table below.

The same assumptions were used as for the 2025 Energy Technology Retirement Cost & O&M Estimate Review – refer to Appendix C.

[24] https://guidetofloatingoffshorewind.com/

Table 3.15 Retirement cost estimate – Floating foundation

Item	Unit	Value
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	275,000
Disposal costs	$/MW (Net)	3,000
Recycling costs	$/MW (Net)	(96,000)
Total retirement costs	$/MW (Net)	182,000

3.4 Large-scale solar photovoltaic

3.4.1 Overview

Utility scale solar PV generation is well established as a significant renewable energy technology in Australia and is currently the cheapest form of electricity generation. Utility scale PV has been deployed in Australia since 2012, with over 37GW installed across Australia as of September 2024[25], and there is expectation that by 2045 approximately 35 GW of PV modules will require retirement which could provide an estimated economic value of A$167 billion[26].

In utility-scale solar PV systems, tens to hundreds of thousands of solar PV modules are typically mounted on single-axis trackers and are connected in strings to inverters, which convert the DC electricity from the modules to AC. For stand-alone solar farms the AC outputs from each of the inverters in the solar farm are aggregated and exported to the network through transformers and switchyards.

3.4.2 Typical options

To date, utility-scale PV plants have typically been installed in either fixed-tilt or single-axis tracking configurations. In fixed-tilt systems, modules are mounted on a static frame oriented to achieve the required generation profile. In Australia fixed tilt systems have traditionally been oriented to the north to maximise annual generation, however, some fixed-tilt systems are arranged with module orientations split between east and west facing to maximise installed capacity on a site and to provide generation that aligns better with morning and evening peaks in demand.

The majority of recently constructed utility-scale solar farms in Australia utilise single-axis tracking systems, where modules are mounted on a torque tube structure which rotates on a north-south axis, allowing the modules to track the sun's movement from east to west. This single axis tracking configuration generally provides a lower LCOE than the fixed tilt systems.

Dual axis tracking systems where structures allow module orientation to move both east-west on a daily basis and north-south on a seasonal basis, come at additional capital expense and have not yet been deployed in the utility scale market in Australia.

Module selection is also a key criteria in solar farm design. Over time modules have evolved to improve efficiency and lower cost. Historically, mono-facial modules (which generate from light capture on one side of the module) have been common however, bi-facial modules, which have the ability to capture indirect light on the rear of the module, have now become more cost efficient and prevalent. Bifacial modules can have a higher output, but how much higher depends on the albedo (proportion of incoming solar radiation that is reflected) and the ability of the module to capture light on the rear site of the module such as structural interference. Bi-facial modules in ideal albedo / ground conditions such as white gravel or concrete, can provide more than 20% gain over mono-facial modules, but with more typical grass and soil the gain can be in the range of 4-15%.

[25] **https://pv-map.apvi.org.au/analyses#:~:text=As%20of%2030%20September%202024,capacity%20of%20over%2037.8%20gigawatts**.
[26] **Recycling and decommissioning of renewable energy tech**

3.4.2.1 Refurbishment

In terms of refurbishment over a 25- or 30-year asset life, the costliest element is likely to be inverters, which could be expected to be refurbished or replaced at approximately halfway through the technical life. For larger arrays employing Single Axis Tracking (SAT), there is likely to also be spend on tracking drive mechanisms, though the main the structural components should be suitable for the full operating life.

To limit impact on generation capacity during refurbishment, central inverter refurbishments / replacements could be staged such that, in the case of a 200MW array, only a small proportion such as 5-10MW of capacity is offline at any point in time. This would need to be weighed up against any potential extra cost from having a crew on site for longer than they would otherwise need to be (if this approach leads to a higher cost).

With regards to the modules themselves, modern modules have quite low degradation rates, and so it is expected that a common approach will be to accept module degradation and modest loss of capacity through to the end of the operating life, with no module replacements (other than faults / failures) over that timeframe.

3.4.3 Recent trends

In 2024, committed utility-scale solar farms averaged 150MW capacity and ranged in size from single-digit to 450MW.[27]

PV module efficiency continues to improve over time and some manufacturers are also increasing module size such that modules exceeding 700 W are now on offer. However, limitations are expected with respect to module size due to manual handling limitations (size and weight). Increases in module efficiency and size allows for a reduction in overall plant footprint, including reduction in cabling and structures for given installed capacity. This can improve capital and retirement costs by reducing the costs associated with Balance of Plant systems. Given the continuing cost reduction in PV module price, some developers have been increasing the DC:AC ratio of the solar farm in an attempt to improve the generation profile in the shoulder periods. This results in installation of more DC equipment for a given capacity of network connection which can complement benefits achieved by increasing module efficiency. A smaller number of larger capacity modules should translate to reduced installation CAPEX as well as retirement costs, due to the reduced number of modules requiring removal, albeit installation and removal costs may be slightly higher per module due to the larger physical size and manual handling requirements.

The move to bifacial modules, particularly dual glass modules, is expected to lead to lower degradation rates and increase the expected lifespan of modules to 30 years[28] or more. This is expected to be an improvement on previous module technology in terms of output over time, with the additional benefit of delaying asset retirement and the associated costs.

Whilst traditionally solar PV facilities were standalone generators, given the value obtained from the generation profile of solar PV there is increasing interest for PV facilities to be combined with Battery Energy Storage Systems (BESS) or at least have capacity for addition of BESS in the future. In particular the potential for DC-coupling (where batteries can connect directly to the DC busbar of the inverter alongside the solar PV connections) offers potential to utilise common MV equipment, which would reduce equipment requirements and hence capital, operating and retirement costs related to a combined facility. However, this is outside the scope of this Report.

Single axis tracking systems that mount one module in a portrait configuration (‘1P trackers’) are by far the most common configuration and therefore form the basis for the ‘Selected hypothetical project’. It should be noted that other configurations are possible for single axis tracking that can reduce equipment requirements, and potentially lower retirement costs, however these are less common due to higher wind loading and increased spacing requirements.

[27] **https://cer.gov.au/markets/reports-and-data/large-scale-renewable-energy-data**
[28] **End-of-Life Management for Solar Photovoltaics | Department of Energy**

3.4.3.1 Summary of changes

Compared with the 2024 estimate which assumed land and development costs were 10% of equipment costs, stated land development costs are now notably higher and are representative of the average of a selection of largely regional areas across NSW, Victoria, South Australia, Tasmania and Queensland.

3.4.3.2 Retirement

In terms of PV module recycling, progress is being made in Australia, both in terms of legislating the need, as well as developing technologies to do so. Victoria, South Australia, Queensland and the ACT have already banned the disposal of solar modules to landfill and NSW now treats solar modules as e-waste[29]. However, the cost of recycling is material. The most common process in Australia is for modules to be physically shredded and then used as some form of aggregate, whereas other processes seeking to extract elements for re-use are more technically complex and therefore cost more. There have been reports of some energy companies stockpiling modules to defer the cost of recycling modules, potentially also benefitting from expected reductions in cost over time.

Only 17% of modules components are presently recycled in Australia, however in the EU, regulations require 85% of module materials to be collected and 80% to be recycled[30] - this has no doubt driven innovation in the sector as well as providing critical mass for industries to develop. Over time, a similar trend may be seen in Australia.

3.4.4 Selected hypothetical project

The selected hypothetical plant is a stand-alone single axis tracking solar farm with capacity of 200 MW AC, in line with previous studies and representing an appropriate size for deployment in the NEM.

Table 3.16 Configuration and performance – Large-scale solar photovoltaic

Item	Unit	Value	Comment
Configuration			
Technology / OEM	-	Single Axis Tracking (SAT)	-
Performance			
Plant DC capacity	MWp	240	Inferred from DC/AC ratio
Plant AC inverter capacity	MVA	240	Additional reactive power allowance for NER compliance
Plant AC grid connection	MW	200	At point of connection
DC:AC ratio (Solar PV to grid)		1.2	Typical range for a utility scale system as seen in industry is 1.1 to 1.3
Auxiliary power consumption and losses	%	2.9	Can be impacted by tracking technology
Total plant size (Net)	MW	200	-
Seasonal rating – Summer (Net)	MW	200	Small output reduction at extreme temperatures however this is relatively rare and the cumulative effect is small
Seasonal rating – Not Summer (Net)	MW	150	Latitude-dependent but some level of reduction expected due to reduced daylight hours and sun closer to the horizon in winter months
Annual Performance			
Average planned maintenance	Days / year		Included in EFOR
Equivalent forced outage rate	%	1.5%	Assuming availability metric of 98.5%
Effective annual capacity factor (AC basis)	%	29%	AC basis, SAT. Varies significantly by geography – sample shown reflective of northern NSW

[29] **Decommissioning by design: reusing and recycling wind farm infrastructure - Energy Magazine**
[30] **Decommissioning by design: reusing and recycling wind farm infrastructure - Energy Magazine**

Item	Unit	Value	Comment
Annual generation (AC)	MWh / year	500,459	Average capacity factor and incorporating assumed availability, Yr1
Annual degradation over design life	%	0.4%	Typical 0.4% degradation rate post Yr 1, though some manufacturers are offering 0.35%[31]

Table 3.17 Technical parameters and project timeline – Large-scale solar photovoltaic

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW/min	Dependent on rate of change in solar irradiance	-
Ramp down rate	MW/min	Dependent on rate of change in solar irradiance	-
Start-up time	Min	N/A	-
Min stable generation	% of installed capacity	0	-
Project timeline			
Time for development	Years	2	-
First year assumed commercially viable for construction	Year	2025	-
EPC programme	Years	1.5	-
– Total lead time	Years	1	-
– Construction time	Weeks	39	Allow 9 months
Economic life (Design life)	Years	30	-
Technical life (Operational life)	Years	30	-

3.4.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined large-scale solar photovoltaic project.

Table 3.18 Development cost estimates – Large-scale solar photovoltaic

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW DC	1,080	Excluding land and development costs
Total EPC cost	$	259,400,000	6% y-o-y reduction. Prices continue to fall, slowing due to labour costs, shipping and supply constraints and global inflation
– Equipment cost	$	146,900,000	-
– Installation cost	$	112,500,000	Assumed increase from previous year based on Producer Price Index (PPI)
Other costs			
Cost of land and development	$	64,742,000	Based on nominal 2Ha/MW DC and an indicative land and development cost of $13.50/m2 representing the average of a selection of largely regional areas across NSW, Victoria, South Australia, Tasmania and Queensland [32]
Fuel connection costs	$	N/A	N/A

[31] **Limited_Warranty_for_LON_Gi_Hi_MOX_10_Solar_Modules_Distributed_Generation_AU_1_c8a7831c18.pdf**
[32] Pumped Hydro Energy Storage Parameter Review for AEMO, GHD, June 2025

3.4.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined large-scale solar photovoltaic project.

Table 3.19 O&M cost estimates – Large-scale solar photovoltaic

Item	Unit	Value	Comment
Fixed O&M cost	$/MW DC/year	12,000	Leveraging economies of scale for a larger installation
Variable O&M cost	$/MWh (Net)	-	Included above
Total annual O&M cost	$/MW DC	2,880,000	-

3.4.7 Retirement cost estimates

Retirement costs for the defined large-scale solar photovoltaic project are outlined in the table below.

Retirement cost estimates are per GHD's work completed for AEMO earlier in 2025[33] – refer to Appendix C.

Table 3.20 Retirement cost estimates – Large-scale solar photovoltaic

Item	Unit	Value
Decommissioning, demolition & rehabilitation costs	$/MW AC	104,000
Disposal costs	$/MW AC	1,000
Recycling costs	$/MW AC	5,000
Total retirement costs	$/MW AC	110,000

3.5 Distribution-scale solar photovoltaic

3.5.1 Overview

Solar PV generation connected to the electrical distribution network (as opposed to connection to the transmission network) is commonly encountered in the Australian context. For the purposes of this Report, the size of solar PV farms suitable for connection to the distribution network are assumed to be of a scale between 5 – 30 MW.

As with utility-scale solar PV systems, albeit at a smaller scale, PV modules (typically on single-axis trackers for large distribution connected facilities) are connected in strings to inverters, which convert the DC electricity from the modules to AC. For stand-alone solar farms the AC outputs from each of the inverters in the solar farm are aggregated and exported to the network – noting the voltage and the pathway for the distribution connected systems may be different than for utility-scale systems.

3.5.2 Typical options

In fixed-tilt systems, modules are mounted on a static frame oriented to achieve the required generation profile. In Australia fixed-tilt systems have traditionally been oriented to the north to maximise annual generation, however, some fixed-tilt systems are arranged with module orientations split between east and west facing to maximise installed capacity on a site and to provide generation that aligns better with morning and evening peaks in demand. For the distribution connected systems some may also be oriented based on rooftop layout.

As with utility-scale, distribution-connected solar PV could employ single-axis tracking, though due to the smaller scale, there may be increased propensity for fixed systems. On a case-by-case basis fixed systems may be preferred for the following reasons:

[33] 2025 Energy Technology Retirement Cost & O&M Estimate Review report, GHD, July 2025

- Single-axis tracking takes up more land due to the need to avoid shadowing of modules, and land may be more constrained for distribution connected solar PV installations.
- The smaller scale may come with assumed unmanned operation, which is less compatible with single axis tracking which requires increased levels of maintenance.
- Single axis tracking comes at higher cost which could be a factor if projects are capital constrained.
- Any roof top systems are likely to be fixed.

Module selection is also a key criterion in solar farm design. Over time modules have evolved to improve efficiency and lower cost, leading to development of bi-facial modules, which have the ability to capture indirect light on the rear of the module, as opposed to mono-facial modules (which generate from light capture on one side of the module) which have historically been more common. Bifacial modules are expected to penetrate into the larger scale of distribution connected PV whilst there may be more tendency for mono-facial modules for smaller systems.

3.5.2.1 Refurbishment

In terms of refurbishment over a 25- or 30-year asset life, as per large scale, the costliest element is likely to be inverters. Whilst smaller scale facilities are more likely to use string inverters, central inverters are still possible at Distribution scale, and these could be expected to be refurbished or replaced at approximately halfway through the asset life. For larger arrays employing Single Axis Tracking (SAT), such as in this instance, there is likely to also be spend on tracking mechanisms, and selected other components, whereas smaller arrays with fixed modules would not incur this cost. In the main, the structural components should be suitable for the full operating life.

During the refurbishment activity, consideration could be given as to the module capacity that is offline at any one time, as taking 5MW offline at a time has a much more significant impact at this scale of facility. At the smaller end of the spectrum, however, this is likely to be addressed as an inherent part of design, by the use of smaller string inverters as opposed to the larger central inverters.

As with large scale, in general the modules themselves are likely to be expected to last the full operating life.

3.5.3 Recent trends

PV module efficiency continues to improve over time and some manufacturers are also increasing module size such that modules exceeding 700 W are now on offer. However, limitations are expected with respect to module size due to manual handling limitations (size and weight). Increases in module efficiency and size allows for a reduction in overall plant footprint, including reduction in cabling and structures for given installed capacity. This can improve capital and retirement costs by reducing the costs associated with Balance of Plant systems. Given the continuing cost reduction in PV module price, some developers have been increasing the DC:AC ratio of the solar farm in an attempt to improve the generation profile in the shoulder periods. This results in installation of more DC equipment for a given capacity of network connection which can complement benefits achieved by increasing module efficiency. A smaller number of larger capacity modules should translate to reduced installation CAPEX as well as retirement costs, due to the reduced number of modules requiring removal, albeit installation and removal costs may be slightly higher per module due to the larger physical size and manual handling requirements.

The move to bifacial modules, particularly dual glass modules, is expected to lead to lower degradation rates and increase the expected lifespan of modules to 30 years[34] or more. This is expected to be an improvement on previous module technology in terms of output over time, with the additional benefits of continued generation using existing BOP equipment as well as delaying asset retirement and the associated costs.

Whilst traditionally solar PV facilities were standalone generators, given the value obtained from the generation profile of solar PV there is increasing interest for PV facilities to be combined with Battery Energy Storage Systems (BESS) or at least have capacity for addition of BESS in the future. In particular the potential for DC-coupling (where batteries can connect directly to the DC busbar of the inverter alongside the solar PV connections) offers potential to utilise common MV equipment, which would reduce equipment requirements and

[34] **End-of-Life Management for Solar Photovoltaics | Department of Energy**

hence capital, operating and retirement costs related to a combined facility. However, this is outside the scope of this Report.

Single axis tracking systems that mount one module in a portrait configuration ('1P trackers') are by far the most common configuration for larger systems and therefore form the basis for the 20 MW 'Selected hypothetical project' at Distribution Scale. It should be noted that other configurations are possible for single axis tracking that can reduce equipment requirements, and potentially lower retirement costs, however these are less common due to higher wind loading and increased spacing requirements.

3.5.3.1 Summary of changes

Compared with the 2024 estimate which assumed land and development costs were 10% of equipment costs, stated land development costs are now notably higher and are representative of the average of a selection of largely regional areas across NSW, Victoria, South Australia, Tasmania and Queensland. Other development and O&M costs are comparable and largely due to increases in CPI.

Total EPC costs have decreased slightly ($1,450/kW in 2024 vs $1,360/kW in 2025 for 20MW project, and $1,600/kW in 2024 vs $1,510/kW in 2025 for 5MW project) due to falling module prices, however labour costs continue to increase.

3.5.3.2 Retirement

Single axis tracking systems remain sufficiently common at this scale to form the basis of the 'retirement scenario', though at smaller scale fixed modules may be considered purely due to capital cost and maintenance.

In terms of PV module recycling, progress is being made in Australia, both in terms of legislating the need, as well as developing technologies to do so. Victoria, South Australia, Queensland and the ACT have already banned the disposal of solar modules to landfill and NSW now treats solar modules as e-waste[35]. However, the cost of recycling is material.

The most common process in Australia is for modules to be physically shredded and then used as some form of aggregate, whereas other processes seeking to extract elements for re-use are more technically complex and therefore cost more. There have been reports of some energy companies stockpiling modules to defer the cost of recycling modules, potentially also benefitting from expected reductions in cost over time.

Only 17% of modules components are presently recycled in Australia, however in the EU, regulations require 85% of module materials to be collected and 80% to be recycled[36] - this has no doubt driven innovation in the sector as well as providing critical mass for industries to develop. Over time, a similar trend may be seen in Australia.

3.5.4 Selected hypothetical project – 20MW

The selected project is a stand-alone single axis tracking solar farm with capacity of 20 MW AC. This is consistent with the 2024 report.

Table 3.21 Configuration and performance – Distribution-scale solar photovoltaic 20MW

Item	Unit	Value	Comment
Configuration			
Technology / OEM	-	20MW Single Axis Tracking	-
Performance			
Plant DC capacity	MWp	26	Inferred from DC/AC ratio
Plant AC inverter capacity	MVA	24	Typical 1.2 ratio, as per utility scale, additional reactive power allowance for NER compliance
Plant AC grid connection	MW	20	At point of connection

[35] **Decommissioning by design: reusing and recycling wind farm infrastructure - Energy Magazine**
[36] **Decommissioning by design: reusing and recycling wind farm infrastructure - Energy Magazine**

Item	Unit	Value	Comment
DC:AC ratio (Solar PV to grid)	-	1.3	Typical range for a utility scale system as seen in industry is 1.1 to 1.3
Auxiliary power consumption and losses	%	2.9	-
Total plant size (Net)	MW	20	-
Seasonal rating – Summer (Net)	MW	20	Small output reduction at extreme temperatures however this is relatively rare and the cumulative effect is small
Seasonal rating – Not Summer (Net)	MW	15	Latitude-dependent but some level of reduction expected due to reduced daylight hours and sun closer to the horizon in winter months
Annual Performance			
Average planned maintenance	Days / year	-	Included in EFOR
Equivalent forced outage rate	%	1.5	Assuming availability metric of 98.5%
Effective annual capacity factor (AC basis)	%	29	AC basis, SAT. Varies significantly by geography – sample shown reflective of northern NSW
Annual generation (AC)	MWh / year	50,046	Average capacity factor and incorporating assumed availability
Annual degradation over design life	%	0.4%	Typical 0.4% degradation rate post Yr 1, though some manufacturers are offering 0.35%[37]

Table 3.22 Technical parameters and project timeline – Distribution-scale solar photovoltaic 20-40MW

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	Dependent on rate of change in solar irradiance	-
Ramp down rate	MW / min	Dependent on rate of change in solar irradiance	-
Start-up time	Min	N/A	-
Min stable generation	% of installed capacity	0	-
Project timeline			
Time for development	Years	1.5	-
First year assumed commercially viable for construction	Year	2025	-
EPC programme	Years	1	-
– Total lead time	Years	0.5	-
– Construction time	Weeks	26	-
Economic life (Design life)	Years	30	-
Technical life (Operational life)	Years	30	-

3.5.5 Development cost estimates – 20MW

The following table provides CAPEX cost estimates for the defined distribution-scale solar photovoltaic project.

[37] Limited_Warranty_for_LON_Gi_Hi_MOX_10_Solar_Modules_Distributed_Generation_AU_1_c8a7831c18.pdf

Table 3.23 Development cost estimates – Distribution-scale solar photovoltaic 20-40MW

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW DC	1,360	Excluding land and development costs
Total EPC cost	$	35,400,000	6% y-o-y reduction. Module prices continue to fall, but rate of change is slowing due to labour costs, shipping and supply constraints and global inflation
– Equipment cost	$	20,000,000	--
– Installation cost	$	15,400,000	Allowed increase from previous year based on PPI
Other costs			
Cost of land and development	$	$7,014,000	Based on nominal 2Ha/MW DC and an indicative land and development cost of $13.50/m2 representing the average of a selection of largely regional areas across NSW, Victoria, South Australia, Tasmania and Queensland [38]
Fuel connection costs	$	N/A	Out of scope

3.5.6 O&M cost estimates – 20MW

The following table provides fixed, variable and total annual O&M cost estimates for the defined distribution-scale solar photovoltaic project.

Table 3.24 O&M cost estimates – Distribution-scale solar photovoltaic 20-40MW

Item	Unit	Value	Comment
Fixed O&M cost	$/MW DC/year	12,500	Slightly reduced economies of scale compared with large scale PV
Variable O&M cost	$/MWh (Net)	-	Included above
Total annual O&M cost	$	325,000	-

3.5.7 Retirement cost estimates – 20MW

Retirement costs for the defined distribution-scale solar photovoltaic project are outlined in the table below.

Retirement cost for this scenario has been developed using a methodology that is consistent with that used for the 200MW and 5MW cases for AEMO earlier in 2025[39] - refer to Appendix C.

Table 3.25 Retirement cost estimates – Distribution-scale solar photovoltaic 20-40MW

Item	Unit	Value
Decommissioning, demolition & rehabilitation costs	$/MW AC	135,000
Disposal costs	$/MW AC	1,000
Recycling costs	$/MW AC	6,000
Total retirement costs	$/MW AC	142,000

3.5.8 Selected hypothetical project – 5 MW

The selected retirement scenario is a stand-alone fixed (east/west orientation) solar farm with capacity of 5 MW AC (ground mount).

[38] Pumped Hydro Energy Storage Parameter Review for AEMO, GHD, June 2025
[39] 2025 Energy Technology Retirement Cost & O&M Estimate Review report, GHD, July 2025

Table 3.26 Configuration and performance – Distribution-scale solar photovoltaic 5-20MW

Item	Unit	Value	Comment
Configuration			
Technology / OEM	-	5MW AC ground mount, split east and west oriented	-
Performance			
Plant DC capacity	MWp	7.5	-
Plant AC inverter capacity	MVA	6	Typical 1.2 ratio, as per utility scale, additional reactive power allowance for NER compliance
Plant AC grid connection	MW	5	At point of connection
DC:AC ratio (Solar PV to grid)		1.5	Ratio of 1.2-1.5 is considered acceptable for this scale particularly given falling PV costs
Auxiliary power consumption and losses	%	2.9%	-
Total plant size (Net)	MW	5	-
Seasonal rating – Summer (Net)	MW	5	Small output reduction at extreme temperatures however this is relatively rare, and the cumulative effect is small
Seasonal rating – Not Summer (Net)	MW	3.5	Latitude-dependent but some level of reduction expected due to reduced daylight hours and sun closer to the horizon in winter months
Annual Performance			
Average planned maintenance	Days / year	-	Included in EFOR
Equivalent forced outage rate	%	1.5	Assuming availability metric of 98.5%
Effective annual capacity factor (AC basis)	%	25	AC basis. Fixed modules split east/west orientation. Varies significantly by geography – sample shown for northern NSW
Annual generation (AC)	MWh / year	10,786	Average capacity factor and incorporating assumed availability. Note AC basis
Annual degradation over design life	%	0.4%	Typical 0.4% degradation rate post Yr 1, though some manufacturers are offering 0.35%[40]

Table 3.27 Technical parameters and project timeline – Distribution-scale solar photovoltaic 5-20MW

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW/min	Dependent on rate of change in solar irradiance	-
Ramp down rate	MW/min	Dependent on rate of change in solar irradiance	-
Start-up time	Min	N/A	-
Min stable generation	% of installed capacity	0	-
Project timeline			
Time for development	Years	1	-
First year assumed commercially viable for construction	Year	2025	-
EPC programme	Years	0.5	-

[40] **Limited_Warranty_for_LON_Gi_Hi_MOX_10_Solar_Modules_Distributed_Generation_AU_1_c8a7831c18.pdf**

Item	Unit	Value	Comment
– Total lead time	Years	0.25	-
– Construction time	Weeks	16	-
Economic life (Design life)	Years	30	-
Technical life (Operational life)	Years	30	-

3.5.9 Development cost estimates – 5 MW

The following table provides CAPEX cost estimates for the defined distribution scale solar photovoltaic project.

Table 3.28 Development cost estimates – Distribution-scale solar photovoltaic 5-20MW

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW DC	1,510	Excluding land and development costs
Total EPC cost	$	11,300,000	6% y-o-y reduction. Prices continue to fall, slowing due to labour costs, shipping and supply constraints and global inflation
– Equipment cost	$	6,400,000	-
– Installation cost	$	4,900,000	Allowed increase from previous year based on PPI
Other costs			
Cost of land and development	$	2,023,000	Based on nominal 2Ha/MW DC and an indicative land and development cost of $13.50/m2 representing the average of a selection of largely regional areas across NSW, Victoria, South Australia, Tasmania and Queensland [41]
Fuel connection costs	$	N/A	N/A

3.5.10 O&M cost estimates – 5 MW

The following table provides fixed, variable and total annual O&M cost estimates for the defined distribution scale solar photovoltaic project.

Table 3.29 O&M cost estimates – Distribution-scale solar photovoltaic 5-20MW

Item	Unit	Value	Comment
Fixed O&M cost	$/MW DC/year	13,360	Minimal change, assuming increases in labour cost offset by reductions in parts costs. Reduced economies of scale vs larger installations
Variable O&M cost	$/MWh (Net)	-	Included above
Total annual O&M cost	$/yr	100,200	-

3.5.11 Retirement cost estimates – 5 MW

Retirement costs for the defined distribution-scale solar photovoltaic project are outlined in the table below.

Retirement cost estimates are per GHD's work completed for AEMO earlier in 2025[42] – refer to Appendix C.

[41] Pumped Hydro Energy Storage Parameter Review for AEMO, GHD, June 2025
[42] 2025 Energy Technology Retirement Cost & O&M Estimate Review report, GHD, July 2025

Table 3.30 Retirement cost estimates – Distribution-scale solar photovoltaic 5-20MW

Item	Unit	Value
Decommissioning, demolition & rehabilitation costs	$/MW AC	200,000
Disposal costs	$/MW AC	1,000
Recycling costs	$/MW AC	7,000
Total retirement costs	$/MW AC	208,000

3.6 Behind-the-meter photovoltaic (rooftop)

3.6.1 Overview

At this scale, commercial rooftop installations typically focus on locations such as schools, shopping centres and carparks. The 100kW threshold aligns with the lower limit of the LRET scheme, while just under 5MW (AC) avoids AEMO registration requirements and is therefore a logical upper bound.

Commercial rooftop PV is a key part of the renewable energy sector, helping businesses reduce energy costs and improve sustainability. Adoption has been driven by falling costs, improved module efficiency, and rising electricity prices. Rooftop systems are typically behind-the-meter, offsetting on-site loads with excess generation either exported at low feed-in tariffs or curtailed. Whilst hybrid PV-BESS systems can improve energy capture, this report focuses solely on PV-only systems.

3.6.2 Typical options

Rooftop systems are more common below ~2MW due to space, structural, and load constraints. They are usually flush-mounted, which reduces efficiency compared to optimally tilted ground-mount systems but offers easier installation and maintenance. Carport-mounted systems provide alternatives where roof space is limited.

3.6.2.1 Refurbishment

In terms of refurbishment over a 25- or 30-year asset life, given fixed modules, the costliest element is likely to be inverters. Given string inverters are typically employed at this scale, replacement frequency is likely to be every 5-10 years throughout the asset life.

However, given the (inherently smaller scale) string inverters, it should be possible to maintain the majority of the generating capacity online at any point in time.

As discussed above, and also at this scale, in general the modules themselves are likely to be expected to last the full operating life.

3.6.3 Recent trends

Silicon-based modules remain standard due to cost and supply chain maturity. Rooftop systems typically use mono-facial modules with smaller form factors to address wind loading and handling, despite industry shifts away from older technologies such as these at larger scales.

String inverters dominate in these comparatively smaller systems, offering better efficiency, reliability, and ease of maintenance than central inverters.

At this scale rooftop PV can provide benefits including displacement of retail tariffs, net metering, virtual power plants (VPPs) or feed in tariffs (as opposed to operating under wholesale arrangements (PPAs) – with the main driver and advantage for rooftop configurations being avoided retail power costs. Rooftop PV may also be simpler to register than distribution scale, particularly when distribution scale exceeds 5MW which triggers more onerous registration processes with AEMO. Rooftop configurations require compliance with local standards (e.g. AS4777) whereas distribution scale installations can require more detailed grid impact studies and may need a dedicated substation. As battery prices are reducing, and feed-in tariffs reduce, battery pairing with rooftop PV is becoming more popular.

3.6.3.1 Summary of changes

No material changes in technology or costs were observed from 2024 to 2025. The relative cost has decreased from $1,300/kW in 2024 to $1,230/kW in 2025 which is largely attributed to falling module prices. O&M costs remain the same.

3.6.4 Selected hypothetical project

The selected project is a stand-alone roof mount solar farm with capacity of 1 MW AC.

Table 3.31 Configuration and performance – Behind-the-meter rooftop photovoltaic

Item	Unit	Value	Comment
Configuration			
Technology / OEM		Roof mount	Flush on relatively flat roof, string inverter
Performance			
Plant DC capacity	MWp	1.2	Tied to DC:AC ratio
Plant AC inverter capacity	MVA	1.0	Tied to Grid Connection Capacity
Plant AC grid connection	MW	1.0	At point of connection
DC:AC ratio (Solar PV to grid)		1.2	Typically 1.2 – 1.5
Auxiliary power consumption and losses	%	2.9%	Losses in operation expected to be very minor
Total plant size (Net)	MW	1.0	AC rating – losses assumes absorbed within DC rating
Seasonal rating – Summer (Net)	MW	1.0	Small output reduction at extreme temperatures however this is relatively rare and the cumulative effect is small
Seasonal rating – Not Summer (Net)	MW	0.75	Latitude-dependent but some level of reduction expected due to reduced daylight hours and sun closer to the horizon in winter months
Annual Performance			
Average planned maintenance	Days / year		Included in EFOR
Equivalent forced outage rate	%	1.5%	Assuming availability metric of 98.5%
Effective annual capacity factor (AC basis)	%	17%	Fixed modules, not inclined. Varies significantly by geography – stated figure for regional NSW - Tamworth[43]
Annual generation (AC)	MWh / year	1467	Average capacity factor and incorporating assumed availability
Annual degradation over design life	%	0.4%	Typical 0.4% degradation rate post Yr 1, though some manufacturers are offering 0.35%[44]

Table 3.32 Technical parameters and project timeline – Behind-the-meter rooftop photovoltaic

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	Dependent on rate of change in solar irradiance	-
Ramp down rate	MW / min	Dependent on rate of change in solar irradiance	-
Start-up time	Min	N/A	-

[43] **Global Solar Atlas**
[44] **Limited_Warranty_for_LON_Gi_Hi_MOX_10_Solar_Modules_Distributed_Generation_AU_1_c8a7831c18.pdf**

Item	Unit	Value	Comment
Min stable generation	% of installed capacity	0	-
Project timeline			
Time for development	Years	0.5	-
First year assumed commercially viable for construction	Year	2025	-
EPC programme	Years	0.5	-
– Total lead time	Years	0.25	-
– Construction time	Weeks	16	-
Economic life (Design life)	Years	25	Consideration given to warranties, rate of module degradation and incremental improvements over time in module efficiency. Reduced vs larger scale installations due to the different spec of modules typically used
Technical life (Operational life)	Years	25	-

3.6.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined behind-the-meter rooftop photovoltaic project.

Table 3.33 Development cost estimates – Behind-the-meter rooftop photovoltaic

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW DC	1,230	Excluding land and development costs
Total EPC cost	$	1,470,000	6% y-o-y reduction. Module prices continue to fall, with rate slowing due to labour costs, shipping and supply constraints and global inflation
– Equipment cost	$	830,000	-
– Installation cost	$	640,000	Allowed increase from previous year based on PPI
Other costs			
Cost of land and development	$	N/A	-
Fuel connection costs	$	N/A	N/A

3.6.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined behind-the-meter rooftop photovoltaic project.

Table 3.34 O&M cost estimates – Behind-the-meter rooftop photovoltaic

Item	Unit	Value	Comment
Fixed O&M cost	$/MW DC/year	15,000	Based on 1 module clean p.a. – particularly relevant due to the horizontal orientation. Lowest economies of scale
Variable O&M cost	$/MWh (Net)	Included above	-
Total annual O&M cost	$	18,000	-

3.6.7 Retirement cost estimates

Retirement costs for the defined behind-the-meter rooftop photovoltaic project are outlined in the table below.

Retirement cost for this scenario has been developed using a methodology that is consistent with that used for the 200MW and 5MW cases for AEMO earlier in 2025[45] - refer to Appendix C.

Table 3.35 Retirement cost estimates – Behind-the-meter rooftop photovoltaic

Item	Unit	Value
Decommissioning, demolition & rehabilitation costs	$/MW AC	256,000
Disposal costs	$/MW AC	1,000
Recycling costs	$/MW AC	13,000
Total retirement costs	$/MW AC	270,000

3.7 Ocean and wave technologies

3.7.1 Overview

Ocean energy technologies utilise the natural movements and characteristics of the ocean to produce electricity. The most developed approaches are based on wave energy and tidal energy, both of which are being demonstrated internationally at pilot and early commercial scales. These technologies remain at a comparatively early stage of deployment relative to wind and solar generation but are considered potential contributors to a diversified renewable energy mix in the longer term. The resource classes listed below are excluded from further analysis for the following reasons:

– **Tidal range:** resources in Australia are geographically concentrated in very specific locations. Although the theoretical tidal range potential is high, it is confined largely to King Sound and the Joseph Bonaparte Gulf in the remote Kimberley region of Western Australia, far from grid infrastructure, rendering this pathway unsuitable for making a material contribution to existing grids such as the NEM or WEM. [46]

– **Ocean thermal energy conversion (OTEC):** has seen very limited global deployment, with the largest operating plant being a 105 kW demonstration project at the Ocean Energy Research Centre in Hawaii.[47]

– **Ocean current:** velocities in Australian waters (e.g. East Australian Current, Leeuwin Current, Antarctic Circumpolar Current and Indonesian Throughflow) are typically below 1 m/s.[48] Given that power output is proportional to the cube of current velocity, conventional turbine-based systems require ~2 m/s flow to achieve rated power, which is rarely available in Australian conditions.

Wave energy technologies are designed to capture the energy contained in surface waves generated by wind. A variety of concepts have been tested, including point absorbers, oscillating water columns, attenuators, and overtopping devices. Performance is highly dependent on local wave climates, and resource availability varies seasonally and geographically. Technical challenges for the sector include device survivability in extreme conditions, efficient energy conversion, and the development of reliable offshore installation and maintenance practices.

Tidal energy can be extracted in two main ways: from tidal range and tidal stream. Tidal range systems use structures such as barrages or lagoons to harness the potential energy of water level differences between high and low tides. Tidal stream systems operate in areas with strong tidal currents, typically using submerged turbines similar in design to wind turbines. The predictability of tidal flows provides a firm generation profile, but suitable

[45] 2025 Energy Technology Retirement Cost & O&M Estimate Review report, GHD, July 2025
[46] Simon P. Neill, Mark Hemer, Peter E. Robins, Alana Griffiths, Aaron Furnish, Athanasios Angeloudis, *Tidal range resource of Australia*, Renewable Energy, Volume 170, 2021, pp. 683–692.
[47] Makai Ocean Engineering, *Ocean Thermal Energy Conversion*, **https://www.makai.com/renewable-energy/otec/**, accessed September 2025.
[48] CSIRO, *Wave energy research*, **https://www.csiro.au/en/research/natural-environment/oceans/wave-energy**, accessed September 2025.

sites are geographically limited, and environmental and marine use considerations are important in project planning.

While both wave and tidal energy technologies are not yet widely deployed at utility scale, they continue to undergo research, development, and demonstration. Future cost reductions, supported by technological learning, supply chain development, and economies of scale, will be required before these technologies can be considered for broad integration into electricity systems.

3.7.2 Typical options

Once an adequate wave or tidal stream resource is identified, ocean energy projects will also be critically dependent on access to seabed areas for foundations, anchors or moorings, along with suitable subsea cable corridors and onshore land parcels for electrical balance of plant and grid connection. Other key requirements will include development consents, planning and environmental approvals, availability of specialist vessels for installation and operations, and proximity to adequate transmission capacity. In addition, survivability in harsh sea environments and efficient offshore maintenance remain key challenges.

Wave energy converters (WECs) can be grouped according to their primary mode of operation, e.g.:

– Oscillating water columns use enclosed chambers in which the rise and fall of the water column forces air through a turbine. The Mutriku 259 kW plant in Spain demonstrates this technology and has produced over 3GWh since 2011.[49] Likewise, the Wave Swell Energy's 200 kW UniWave200 operated in King Island, Tasmania for 18 months.[50]
– Point absorbers are compact buoyant devices that oscillate in heave against a fixed or inertial reference, with CorPower Ocean and Ocean Power Technologies among the developers demonstrating extended sea trials. The CorPower Ocean C4 300 kW WEC was installed in Portuguese waters for demonstration and prototype certification in 2023.[51]
– Attenuators or line absorbers are long multi-segment devices aligned with wave direction, extracting power from relative motion between sections. The Pelamis prototype was a prominent historical example at 750 kW, which was tested in Orkney, Scotland from 2004-2007.[52] The Moored MultiMode Multibody (M4) Wave Energy Demonstration Project is a demonstration project deployed off Western Australia in 2024[53].
– Oscillating wave surge converters are bottom-hinged flaps that swing with surge motion in shallow to intermediate waters, with full-scale prototypes tested in Europe including AW-Energy's WaveRoller® (350kW) which operated for 2 years off the Portuguese coast from 2019 to 2021.[54]
– Overtopping devices capture water in a raised reservoir before releasing it through low-head turbines, demonstrated in prototype form by Wave Dragon which was tested between 2003 and 2009.[55]
– Pressure-differential and membrane devices, such as Bombora's *mWave*, use submerged flexible chambers to deform with wave action, with ongoing trials in European waters[56].

Tidal stream energy devices have shown stronger convergence in design. Most commercial development centres on horizontal-axis turbines, drawing on experience from wind turbine engineering. Device classes can be distinguished by scale: kW-class turbines (50–500 kW) have been deployed for trials and local generation, while MW-class turbines (1–1.5 MW per rotor) are now deployed in multi-device arrays such as MeyGen in Scotland which utilised 4 x 1.5 MW tidal turbines.[57] Foundations and platforms vary with site conditions, including monopiles, pinned tri-piles, gravity-bases and floating moored platforms. Gravity-base foundations have been applied at MeyGen, while smaller arrays have used piled systems. Electrical export architectures typically use subsea collector cables connected via wet-mate systems, with array growth achieved through staged turbine

[49] Alberto Peña, Iñigo Bidaguren, Urko Izquierdo, Gustavo Adolfo Esteban, Jesús María Blanco and Iñigo Albaina, *The Mutriku Breakwater Wave Plant: Improvements and Their Influence on the Levelized Cost of Electricity (LCoE),* J. Ocean Eng. Technol. April 2025; 39(2): 205-211.
[50] ARENA, **https://arena.gov.au/projects/uniwave200-king-island-project-wave-swell/**, accessed September 2025
[51] **CorPower Ocean HiWave-5 Project | Tethys**. Accessed September 2025.
[52] **Pelamiswave.com**. Accessed September 2025.
[53] **Uwa.edu.au**. Accessed September 2025
[54] **https://www.offshore-energy.biz/waveroller-emerges-from-the-depths-of-atlantic/?utm_source=marineenergy&utm_medium=email&utm_campaign=newsletter_2021-08-03**
[55] **Wave Dragon Pre-Commercial Demonstration Project | Tethys,** Wave Dragon Pre-Commercial Demonstration Project, Accessed September 2025
[56] **Bomborawave.com**, Latest News, Accessed September 2025.
[57] Tethys database, **https://tethys.pnnl.gov/project-sites/meygen-tidal-energy-project**, accessed September 2025

additions. Tidal generation benefits from a highly predictable resource, but effective capacity factors are site specific and subject to flow speeds, wake effects and environmental constraints.

3.7.3 Recent trends

Activity across the ocean-energy sector during the last few years has been characterised by a combination of concentrated progress in tidal stream and incremental but visible advances in wave-energy demonstration programmes. Public-sector funding and targeted R&D calls have increased in scale and scope (notably a major US Department of Energy open-water testing funding round for wave energy and coordinated EU research calls for both wave and tidal energy), and private capital injections have supported a small number of developers to advance MW-scale prototypes toward extended sea trials or early commercial execution.

Wave-energy activity remains demonstration-led and technologically diverse. Several device developers advanced notable at-sea milestones between 2023 and 2025 including large-scale prototype test programmes. Examples include inspection and upgrade activity and continued verification work on CorPower Ocean's C4 device following its ocean deployment program, the final test and assembly phases for Bombora's 1.5 MW mWave demonstrator, and the formal start of construction of Eco Wave Power's MW-scale Porto project under a concession agreement. At the same time, long-duration device operation is still uncommon: most WEC sea trials historically have recorded operational testing measured in months rather than multi-year continuous service, although there are long-running exceptions (notably the Mutriku oscillating-water-column plant and some prolonged UniWave demonstrations). These developments indicate progress on survivability, component verification and supply-chain mobilisation, while underlining that commercial, multi-device wave farms have not yet been realised at scale.

Tidal-stream development has continued to consolidate around staged, multi-device deployments and has exhibited clearer near-commercial pathways than wave energy. Several projects have demonstrated multi-device, grid-connected operation or extended utility-grade availability: the MeyGen project completed incremental turbine deployments to reach a 6 MW operational configuration and other array operators have demonstrated staged growth through additional turbine installations; smaller utility arrays such as Nova Innovation's Shetland deployments have similarly scaled by staged turbine additions. This pattern reinforces the emerging distinction in maturity between tidal-stream (where site concentration and predictable resource provide a feasible scaling route) and wave technologies (which remain more concept-diverse).

The past few years have seen continued investment in – and the opening or commissioning of – new open-sea test centres and grid-connected berths (in Europe, North America and the Asia-Pacific). Accredited facilities such as the European Marine Energy Centre (EMEC), Korea Research Institute of Ships & Ocean Engineering – Wave Energy Test Site, the Fundy Ocean Research Centre for Energy (FORCE) and PacWave (US) continue to host the majority of full-scale grid-connected trials. The International WaTERS network aims to drive collaboration and knowledge transfer between open-sea test centres and global regions and is supported by IEA. The increased availability of pre-consented berths, subsea export infrastructure and standardised test protocols is lowering the barrier to repeated field tests and enabling more rigorous data collection.

There is a clear sectoral emphasis on reducing the cost and risk of array deployment through improved subsystem maturity (for example power-take-offs, quick-connection/wet-mate electrical systems, and remote condition monitoring) rather than single-point investment only in full-scale WEC hull forms. Programmes such as Wave Energy Scotland's competitive subsystem development pathway exemplify this focus, and industry reporting shows greater investor interest in developers that demonstrate robust subsea electrical and connection solutions. At project level, standardisation of array electrical architectures (collector cables, subsea substations, modular wet-mate connectors) and attention to vessel logistics and seasonal weather windows are evident priorities for cost reduction and availability improvement.

Publicly available, verifiable data on full-system capital costs and long-term operational performance for multi-device ocean farms remain scarce. Recent sector statistics and annual reviews show incremental increases in reported device deployments and private investment but underline the limited size of the commercial pipeline relative to mature generation technologies. As a consequence, academic and industry cost projections commonly rely on technology-learning assumptions and scenario-based LCOE modelling. Therefore, AEMO's cost parameterisation for 2025 should continue to treat wave and tidal stream cost estimates as having high uncertainty and to apply sensitivity ranges that reflect limited as-built benchmarking. Apart from these global trends, recent local developments in the industry have included wave energy technology trials in Western Australia (Albany M4 Demonstration Project) and King Island (UniWave 200 – 200 kW) however both of these facilities are now decommissioned.

3.7.3.1 Summary of changes

Compared to the 2024 report, for tidal technology, the array capacity was changed from 20 x 0.1MW units to 4 x1.5 MW to reflect a more realistic scenario based on the MeyGen project.

For wave energy, the array capacity was changed from 20 x 0.1MW units to 5 x 0.3MW units to reflect a more realistic scenario based on the CorPower project.

3.7.4 Selected hypothetical wave energy project

Table 3.36 Configuration and performance – Wave energy project

Item	Unit	Value	Comment
Configuration			
Technology / OEM	-	Generic Wave Energy Converter	OEMs such as Waveswell, CorPower, Bombora are all developing their unique technologies.
Make model	-	N/A	Based on generic installation
Unit size (Nominal)	MW AC	0.3	Similar in scale to the CorPower's Point absorbers or Wave Swell's Oscillating Water Column plant.
Number of units		5	Similar in scale to the CorPower's C4 project
Performance			
Total plant size (Gross)	MW AC	1.5	-
Auxiliary power consumption and losses	%	3%	Electrical losses from cables and wave energy converter.
Total plant size (Net)	MW AC	1.455	-
Seasonal rating – Summer (Net)	MW AC	1.455	No losses from high temperatures
Seasonal rating – Not Summer (Net)	MW AC	1.455	No losses from icing or low temperatures
Annual Performance			
Average planned maintenance	Days / year	-	-
Equivalent forced outage rate	%	20%	An estimate based on demonstration projects. Wave energy converters are nascent technologies, which are exposed to harsh ocean conditions, resulting in a higher outage rate compared to other technologies.
Effective annual capacity factor	%	35%	While some OEMS claim up to 60% capacity factor, there is no proven track record due to the early stage of the technology. Therefore, 35% was used based on a CSIRO assumption [58]
Annual generation	MWh	4602	-
Annual degradation over design life	%	1	A simplified linear degradation applicable to annual energy generation.

[58] CSIRO, Wave Energy Cost Projections – a report for Wave Swell Energy Limited, 2021

Table 3.37 Technical parameters and project timeline – Wave energy project

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	Resource dependent	-
Ramp down rate	MW / min	Resource dependent	-
Start-up time	Min	0	-
Min stable generation	% of installed capacity	Near 0	-
Project timeline			
Time for development	Years	5	Site investigations, approvals as well as further testing. Approvals may take longer than other technologies due to a lack of regulatory framework for wave energy.
First year assumed commercially viable for construction	Year	2045	Based on assumptions for learning curves in[58], for a conservative scenario for LCOE
EPC programme	Years	2	-
– Total lead time	Years	1	From NTP to COD
– Construction time	Weeks	52	From NTP to first wave energy converter delivered to site
Economic life (Design life)	Years	20	Estimate based on [59]
Technical life (Operational life)	Years	25	Estimate based on [60]

3.7.5 Development cost estimates – Wave energy

The following table provides CAPEX cost estimates for the defined wave energy project.

Table 3.38 Development cost estimates – Wave energy

Item	Unit	Value	Comment
CAPEX construction			
Relative cost	$/kW (Net)	14,950	Estimate based on upper projections of academic research[61], noting that technology is still in a nascent stage
Total CAPEX cost	$	22,425,000	-
– Equipment cost	$	17,940,000	Based on a 4:1 ratio of equipment to installation cost
– Installation cost	$	4,485,000	Based on a 4:1 ratio of equipment to installation cost
Other costs			
Cost of seabed lease and development	$	627,900	Based on 2.8% of CAPEX, noting that seabed for wave energy plants will most likely be leased.

3.7.6 O&M cost estimates – Wave energy

The following table provides fixed, variable and total annual O&M cost estimates for the defined wave energy project.

[59] CSIRO, Wave Energy Cost Projections – a report for Wave Swell Energy Limited, 2021
[60] CSIRO, Wave Energy Cost Projections – a report for Wave Swell Energy Limited, 2021
[61] **https://www.mdpi.com/1996-1073/15/5/1732**

Table 3.39 O&M cost estimates – Wave energy

Item	Unit	Value	Comment
Fixed O&M cost	$/MW/year (Net)	529,900	Assumed as 4% of CAPEX
Variable O&M cost	$/MWh (Net)	-	Included in the fixed cost above
Total annual O&M cost	$	596,092	-

3.7.7 Retirement cost estimates – Wave energy

Retirement costs for the defined wave energy project are outlined in the table below.

As wave energy is still a nascent technology, learnings from offshore wind were used to determine ratios for retirement costs to CAPEX. The larger retirement cost estimates for wave energy also are indicative of the small capacity of wave energy projects.

Table 3.40 Retirement cost estimates – Wave energy

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	1,863,000	Based on the same ratio of decommissioning to CAPEX as for offshore wind
Disposal costs	$/MW (Net)	9,000	As there is no track record, this is based on the same assumption of breakdown of retirement costs as for offshore wind
Recycling costs	$/MW (Net)	(275,000)	As there is no track record, this is based on the same assumption of breakdown of retirement costs as for offshore wind
Total retirement costs	$/MW (Net)	1,597,000	As there is no track record, this is based on the same assumption of breakdown of retirement costs as for offshore wind

3.7.8 Selected hypothetical tidal stream project

Table 3.41 Configuration and performance – Tidal stream project

Item	Unit	Value	Comment
Configuration			
Technology / OEM	-	N/A	-
Make model	-	Generic Tidal Stream Turbine	-
Unit size (Nominal)	MW AC	1.5	Based on Meygen project[62]
Number of units		4	-
Performance			
Total plant size (Gross)	MW AC	6	-
Auxiliary power consumption and losses	%	3%	Electrical losses from tidal stream turbines and cables up to substation.
Total plant size (Net)	MW AC	5.82	-
Seasonal rating – Summer (Net)	MW AC	5.82	No losses due to high temperatures
Seasonal rating – Not Summer (Net)	MW AC	5.82	No losses due to icing or low temperatures
Annual Performance			
Average planned maintenance	Days / year	-	-

[62] https://tethys-engineering.pnnl.gov/sites/default/files/publications/MeyGen%20Lessons%20Learnt%20Executive%20Summary.pdf

Item	Unit	Value	Comment
Equivalent forced outage rate	%	5%	Based on reported availability of Meygen project in [62]
Effective annual capacity factor	%	34%	Based on reported capacity factor of Meygen project in [62]
Annual generation	MWh	17,870	-
Annual degradation over design life	%	1	A simplified linear degradation applicable to annual energy generation.

Table 3.42 Technical parameters and project timeline – Tidal stream project

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	Resource dependent	-
Ramp down rate	MW / min	Resource dependent	-
Start-up time	Min	0	-
Min stable generation	% of installed capacity	Near 0	-
Project timeline			
Time for development	Years	4 to 5	A rough estimate including site investigation and approvals. Approvals may take longer due to the lack of a regulatory framework around tidal stream energy.
First year assumed commercially viable for construction	Year	2040	Assumed learning curve is applicable moving forward.
EPC programme	Years	2	From NTP to COD
– Total lead time	Years	1	From NTP to first tidal stream turbine delivered to site.
– Construction time	Weeks	52	For installation of tidal stream foundations, turbines and cables.
Economic life (Design life)	Years	25	Estimate based on Meygen project in [62]
Technical life (Operational life)	Years	25	Estimate based on Meygen project in [62]

3.7.9 Development cost estimate – Tidal stream

The following table provides CAPEX cost estimates for the defined tidal stream project.

Table 3.43 Development cost estimates – Tidal stream

Item	Unit	Value	Comment
CAPEX construction			
Relative cost	$/kW (Net)	12,400	Estimate based on upper projections of academic research[63], noting that technology is still in a nascent stage
Total CAPEX cost	$	72,168,000	-
– Equipment cost	$	57,734,000	Based on a 4:1 ratio of equipment to installation cost
– Installation cost	$	14,434,000	Based on a 4:1 ratio of equipment to installation cost
Other costs			

[63] **https://www.mdpi.com/1996-1073/15/5/1732**

Item	Unit	Value	Comment
Cost of seabed lease and development	$	2,382,000	Based on 3.3% of CAPEX, noting that seabed for tidal energy plants will most likely be leased.
Fuel connection costs	$	N/A	Out of scope

3.7.10 O&M cost estimates – Tidal stream

The following table provides fixed, variable and total annual O&M cost estimates for the defined tidal stream project.

Table 3.44 O&M cost estimates – Tidal stream

Item	Unit	Value	Comment
Fixed O&M cost	$/MW/year (Net)	$496,800	Based on 3.3% of CAPEX, in the same order of magnitude as the Meygen project and academic research.
Variable O&M cost	$/MWh (Net)		-
Total annual O&M cost	$	$2,981,000	-

3.7.11 Retirement cost estimates – Tidal stream

Retirement costs for the defined tidal stream project are outlined in the table below.

Similarly to wave energy, as tidal energy is still a relatively nascent technology, learnings from offshore wind were used to determine ratios for retirement costs to CAPEX.

Table 3.45 Retirement cost estimates – Tidal stream

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	1,548,000	Based on the same ratio of decommissioning to CAPEX as for offshore wind
Disposal costs	$/MW (Net)	7,000	As there is no track record, this is based on the same assumption of breakdown of retirement costs as for offshore wind
Recycling costs	$/MW (Net)	(229,000)	As there is no track record, this is based on the same assumption of breakdown of retirement costs as for offshore wind
Total retirement costs	$/MW (Net)	1,326,000	As there is no track record, this is based on the same assumption of breakdown of retirement costs as for offshore wind

3.8 Concentrated solar thermal

3.8.1 Overview

Technologies known as Concentrated Solar Thermal (CST), also known as Concentrated Solar Power (CSP), generally have some elements in common:

- Mirrors/collectors deployed over a large area to collect solar energy.
- Solar energy redirected onto a comparatively small solar receiver.
- Transfer of the energy to a thermal fluid which absorbs the energy.
- Either uses the energy immediately for power generation or stores the energy for a period of time, providing time-shifting of the power generation.
- Requires a series of heat exchangers to transfer the energy from the fluid to steam, and then the steam system including demineralised water plant, deaerator, steam turbine and cooling infrastructure. In the case

of molten salt systems, the thermal fluid also requires 'hot' and 'cold' tanks, in between which the fluid passes as it either picks up energy or discharges it.

CST technology is generally classified as either "line focused", where the energy is focused on a linear structure and single-axis trackers are used or "point focused" where energy is directed to a single focal point like a receiver tower.

3.8.2 Typical options

Line focused systems use single-axis trackers to improve energy absorption across the day, increasing the yield by modulating position depending on the angle of incoming solar radiation and allowing this to be redirected onto a collector.

Currently most line focused concentrating systems are Parabolic Trough Collectors (PTCs) – with a line of curved mirrors focusing solar radiation on a heat receiver tube, together with an associated support structure and foundations. Often PTCs are connected together into a chain which the heat transfer fluid flows through, so achieving better economies of scale. The heat transfer fluid exchanges heat to produce superheated steam which typically passes through a steam turbine to generate power. An alternative, but less common, linear system uses a device called Fresnel collectors. These employ an array of relatively flat mirrors and redirect the sun's rays onto a linear receiver located some metres above the mirrors, though (unlike PTCs) not physically connected to them.

Point focused solutions are dominated by Solar Towers, also known as Power Towers. A large number (thousands) of heliostats (mirrors) are located in a circular or semi-circular arrangement around a tall central tower which has a receiver. The heliostats operate in double-axis tracking mode. The receiver absorbs the heat into a heat transfer medium (e.g. molten salt), typically transfers the heat to water to produce steam and drive a turbine to generate power. The advantage of these point focused systems is that they can operate at higher temperatures than line focused systems and so produce higher temperature (higher grade) steam, which allows greater efficiencies and more energy storage per unit mass of molten salt. Increasing project capacity increases economies of scale up to a point, most notable in terms of steam turbine efficiency with scale, but also in production of the various elements such as heliostats. Once the heliostat array gets large, challenges emerge in terms of being able to accurately focus on the tower from a greater distance, necessitating more robust supports and potentially more accurate controls / positioners.

3.8.3 Recent trends

Historically, most CST installations have been linear parabolic trough type, and as of 2010, a total installed base globally of 1.2GW[64], increasing to 1.9GW by early 2012. Project scale continues to increase with typical projects as large as 700MW and 17.5 hours of storage[65]. A 2023 project in UAE (Noor 1) is notable in terms of scale as it incorporates 2 x 200MW parabolic trough facilities alongside a 100MW tower installation and 250MW of 'traditional' PV.

Numerous solar tower installations have taken place over the last 10 years or so across a number of jurisdictions, including Morocco, Chile and China, with power outputs and energy storage durations in the ballpark rough order of magnitude of the scale proposed for the "hypothetical project" below.[66]

The installed capacity of CST remains relatively small compared with conventional PV, at circa 7GW globally by 2023[67], with growth to these levels promoted by incentives in the main historical markets being USA and Spain, and new developments in other geographies such as the Middle East and China. China is increasingly focused on CST and has developed hybrid projects complementing CST with traditional PV and wind generation. This approach is seeing more widespread adoption over time as it allows for wind and solar to be directly exported to the grid, meaning more of the CST output can be directed to storage for time-shifting to other times of day.

A recently published report[68] focused on China cites significant activity in CST in China, with a total of 8 CST facilities to be commissioned in 2025 (7 towers and 1 Fresnel) with total capacity of 800MW and average storage

[64] **http://iea-etsap.org/E-TechDS/PDF/E10IR_CSP_GS_Jan2013_final_GSOK.pdf**
[65] **https://arena.gov.au/assets/2019/01/cst-roadmap-appendix-1-itp-cst-technology.pdf**
[66] The Australian Concentrating Solar Thermal Value Proposition, Fichtner Australia, Oct2023
[67] **https://www.sciencedirect.com/science/article/abs/pii/S0306261924017793**
[68] Concentrated Solar Therman (CST) in China, Australian Solar Therman Research Institute, Sep2025

of 11.5 hours. The report presents some high level recent and projected learning rates in terms of LCOE. It is expected that these learning rates are however not immediately applicable to the Australian context, given all the reported installations have occurred in China and there has been no utility scale installations delivered in Australia. Also, in terms of cost, Chinese labour rates are substantially lower than in Australia, which means that decreases in equipment costs have a much more marked impact on total CAPEX in the Chinese context. For the portion of cost attributable to labour, Australian labour rates are increasing over time, and additionally the power block (over 30% of the capex in Fichtner's report[69]) is regarded as a mature technology and this component is not expected to benefit from significant cost down over time.

Due to the lack of existing CST facilities in Australia, the Australian Solar Thermal Research Institute (ASTRI) recently commissioned Fichtner to complete a study on CST in the Australian context[70]. The study included development of a cost model for different plant configurations which breaks the project cost down into three high level elements being the solar field, thermal energy storage and power block. They chose a hypothetical location on the mid-coast of NSW for their reference case.

From a technical perspective, alternative approaches to CST are emerging as a result of the drive for cost reduction and efficiency gains. The Vast Solar approach out of Australia seeks to leverage a greater number of smaller towers with corresponding smaller heliostat arrays, as well as using liquid sodium instead of molten salt. Sodium melts at a much lower temperature of 98˚C which is a range at which trace heating is effective, meaning the medium can be readily re-melted if required. Other approaches include heat transfer through falling particles in place of the more 'traditional' molten salt, or heat collection in heat blocks such as carbon.

As storage durations have tended to increase with CST deployment over time this has flowed through to higher capacity factors for CST installations, now exceeding 50% for 8 hours storage[71]. As a result of this and the 'hybridisation' of generation (complementing with PV and wind), CST costs (LCOE basis) dropped by more than 60% between 2010 and 2022[72].

The International Energy Agency forecast dramatic growth in CST, 10-fold through to 2030 and then a further 4-fold increase to 2040 (281GW)[73].

Little public information is available in terms of asset retirement for CST given the relatively small and recent installed base. However, it is proposed that, for a solar tower configuration, there should be options for metal recycling for the tower construction itself (provided it is made of steel) and also for the support structures and tracking mechanisms for the heliostats. The heliostats themselves may be more challenging to recover materials from given the typical combination of metal with glass coating. Over time and assuming the market grows as anticipated by IEA, it is expected there will be similar recycling requirements imposed by state or federal jurisdictions, as has been the case for End-Of-Life PV modules. As this takes place, and as the number of heliostats reaches a critical mass, it will also promote focus on and development of recycling facilities, and with market competition, it is reasonable to also expect a progressive reduction in recycling costs.

3.8.3.1 Summary of changes

Compared to 2024 report[74], storage duration has now been defined at 14 hours to align with the primary reference case in Fichtner's ASTRI paper[75], and capacity factor has been reduced to 55% to be in line with the range quoted by Fichtner / ASTRI, which flows through to a lower annual generation figure. Ramp rate is slightly higher, restart time is also longer, and operational life of 25-30 years is lower than previous, all to align with published literature as referenced. CAPEX cost is higher at $6,900/kW (2024 reports $6,104/kW), aligned with Fichtner's report with indexation, and O&M cost is slightly higher than previously reported, in line with the ITP report referenced.

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[69] The Australian Concentrating Solar Thermal Value Proposition, Fichtner Australia, Oct2023
[70] The Australian Concentrating Solar Thermal Value Proposition, Fichtner Australia, Oct2023
[71] **Life cycle assessment (LCA) of a concentrating solar power (CSP) plant in tower configuration with different storage capacity in molten salts - ScienceDirect**
[72] **https://www.sciencedirect.com/science/article/abs/pii/S0306261924017793**
[73] **Concentrated solar: An unlikely comeback? — RatedPower**
[74] Aurecon (2024) Energy Technology Cost and Parameters Review – Revision 3
[75] **65277571ffb6ccecd3d53187_Final Report - CST Value Proposition web.pdf**

3.8.4 Selected hypothetical project

The selected hypothetical project is a standalone concentrating solar tower with solar field capacity of 720 MWth and net electrical capacity of 140 MW AC via a steam cycle. The plant utilises molten salt as heat transfer fluid capable of 14 hours of storage, to align with the key Fichtner / ASTRI study[76].

Table 3.46 Configuration and performance – Concentrated solar thermal

Item	Unit	Value	Comment
Configuration			
Technology / OEM		Solar Tower with Thermal Energy Storage (TES)	Based on typical options and recent trends which exhibit central tower(s) storing energy during the day and generating for 14 hours through evening peak and overnight period e.g. 5pm to 8am.
Solar field capacity	MWth	720	-
Power block		1 x Steam Turbine, dry cooling system	-
Net Capacity	MW	140	To align with the Fichtner / ASTRI study
Power cycle efficiency	%	42	-
Heat transfer fluid		Molten Salt	Most common heat transfer medium
Storage	Hours MWh Thermal	14 4,667	To align with the Fichtner / ASTRI study, 14h has been selected, which is typically sufficient to sustain output through evening period. MWh also per Fichtner study
Storage type		2 tank	-
Storage description		Molten salt thermal mass	-
Performance			
Total plant size (Gross)	MW	150	-
Auxiliary power consumption and losses	%	6.7%	-
Total plant size (Net)	MW	140	-
Seasonal rating – Summer (Net)	MW	140	-
Seasonal rating – Not Summer (Net)	MW	140	-
Annual Performance			
Average planned maintenance	Days / year	7	Industry typical 98% availability for process plant
Equivalent forced outage rate	%	3	Assumed outside of capacity factor
Effective annual capacity factor	%	55	55-65% cited by Fichtner / ASTRI[77]
Annual generation	MWh	654,000	Allowing for forced outage rate

[76] The Australian Concentrating Solar Thermal Value Proposition, Fichtner Australia, Oct2023
[77] **Solar at Night**

Table 3.47 Technical parameters and project timeline – Concentrated solar thermal

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	8.4	Ramp rate of 6% per minute[78]
Ramp down rate	MW / min	8.4	Ramp rate of 6% per minute[79]
Start-up time	Min	Hot: 2.5h[80]	-
Min stable generation	% of installed capacity	25[81]	-
Project timeline			
Time for development	Years	2-3	Industry typical
First year assumed commercially viable for construction	Year	2025	-
EPC programme	Years	2-3.5	-
– Total lead time	Years	2	Typical for large process plant, variable depending on market supply/demand
– Construction time	Weeks	91	21 months
Economic life (Design life)	Years	25-30	-
Technical life (Operational life)	Years	25-30[82]	-

3.8.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined concentrated solar thermal project.

Table 3.48 Development cost estimates – Concentrated solar thermal

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW (Net)	6,900	Excluding land and development cost, indexed per PPI
Total EPC cost	$	964,000,000	Per Fichtner/ASTRI, indexed per PPI
– Equipment cost	$	434,000,000	Assumed 45% of EPC cost
– Installation cost	$	530,000,000	Assumed 55% of EPC cost – typical for packaged plant with stick-built ancillaries, expected rel. high due solar collectors etc.
Other costs			
Cost of land and development	$	94,416,000	Based on an allowance of 700Ha and an indicative land and development cost of $13.50/m2 representing the average of a selection of largely regional areas across NSW, Victoria, South Australia, Tasmania and Queensland [83]
Fuel connection costs	$	N/A	N/A

[78] Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables, 2018
[79] Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables, 2018
[80] Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables, 2018
[81] Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables, 2018
[82] **https://arena.gov.au/assets/2019/01/cst-roadmap-appendix-1-itp-cst-technology.pdf**
[83] Pumped Hydro Energy Storage Parameter Review for AEMO, GHD, June 2025

3.8.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined concentrated solar thermal project.

Table 3.49 O&M cost estimates – Concentrated solar thermal

Item	Unit	Value	Comment
Fixed O&M cost	$/MW/year (Net)	137,000	Based on 3% of CAPEX for power block and TES, and 1% of CAPEX for the solar field, where CAPEX elements are indexed from the Fichtner report using PPI. Overall value of O&M is in line with ITP Report T0036 "Informing a CSP Roadmap for Australia" which mentions 2% of overall CAPEX
Variable O&M cost	$/MWh (Net)	-	Included in Fixed O&M cost
Total annual O&M cost	$	19,200,000	-

3.8.7 Retirement cost estimates

Retirement costs for the defined concentrated solar thermal project are outlined in the table below. These values can also be found in Appendix C.

Table 3.50 Retirement cost estimates – Concentrated solar thermal

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	246,000	Balance not attributable to disposal or recycling
Disposal costs	$/MW (Net)	141,000	-
Recycling costs	$/MW (Net)	(3,000)	Net positive revenue
Total retirement costs	$/MW (Net)	384,000	Inclusive of all of the above

3.9 Reciprocating engines

3.9.1 Overview

Reciprocating engines, also known as piston engines, convert pressure into rotational motion using pistons. Their application spans backup and distributed power generation, grid-scale peaking power generation, remote and off-grid energy, industrial and mining operations, marine and agricultural machinery. The technology is advantageous for its reliability and flexibility with modular and scalable designs. Reciprocating engine generators range in capacity from 2 kW to 20 MW, although for grid applications they are at the upper end of the range.

3.9.2 Typical options

Reciprocating engines are large-scale internal combustion engines and represent a widely recognized technology deployed in various applications within the NEM. These engines are generally classified by their speed, stroke, configuration, and type of ignition/fuel, and are typically paired with a generator on the same base frame for power generation purposes. Reciprocating engines use synchronous generators to produce alternating current, delivering power and supporting system strength of the NEM.

Reciprocating engines for power generation are typically modular in nature and are comprised of:

– Core engine and generator sets.
– Fuel and cooling infrastructure.
– Electrical protection and control systems.
– Emission and environmental control components.
– Structural and support facilities such as stack structures and fuel tanks.

Reciprocating engines have various uses in a network due to their ability to provide fast frequency response, spinning reserve, and ramp rate support as they are highly dispatchable with short start times compared to other synchronous generators. Uses include:

– Grid-firming and peaking plants to support renewables.
– Providing black start capability.
– Hybrid power stations.
– Micro-grids and/or islanded systems.

They can operate on natural gas, diesel, dual-fuel, biofuel, and hydrogen when blended. Grid connected reciprocating engines are typically medium-speed engines, which operate between 500 – 1000 revolutions per minute (RPM). High-speed engines with greater than 1000 RPM are more common in backup applications as they are typically less efficient with a shorter life. The modular nature of reciprocating engines allows for multiple engines to be installed in parallel for scalability and to provide redundancy, with the ability to take individual units offline without significantly compromising full capacity.

Reciprocating engines can operate across a wide load range, with high load typically defined as above 80–90% of rated capacity and low load as below 50%. High-load operation is generally associated with peaking duty, dispatchable generation during periods of high demand, or continuous operation in baseload or backup roles. Low-load operation may be used to provide system support services such as frequency control or spinning reserve.

3.9.3 Recent trends

Current market offerings encompass a wide range of sizes and capacity factors, enabling deployment across diverse applications from small-scale distributed generation to larger utility-scale installations. A notable example of a NEM-connected gas fired reciprocating engine asset is the AGL Energy’s 210 MW Barker Inlet Power Station (BIPS).

Natural gas-fired reciprocating engines are being deployed as a complementary technology more frequently to balance renewables off-grid, as they address grid stability challenges from intermittent renewable capacity, with gas turbines a more frequent option in the NEM. Their operational flexibility enables deployment as peaking stations during high demand periods or as synchronous condensers for reactive power support, although no NEM-connected assets have been modified to be used as synchronous condensers. The technology's fuel efficiency and rapid response capabilities address critical grid stability requirements, including fast start times, effective turndown ratios, responsive operation during network variability events, and different operational modes (high and low load operations). While extended low-load operation can influence component wear and maintenance requirements, operational mode is not expected to materially affect asset life.

Contemporary market trends indicate a shift toward incorporating low emissions solutions in new reciprocating engine developments. This transition primarily involves fuel blending strategies and hydrogen firing capabilities, with new installations designed to accommodate hydrogen concentrations ranging from 10% to 100%[84], on a volume basis. Reciprocating engines can operate on various fuels, including natural gas, diesel, biogas, and hydrogen blends, providing operational flexibility for transitioning energy systems. The potential for hydrogen or other fuel blends is not expected to materially impact asset life or retirement estimates for existing assets within the scope of this review. Of note is CCS is not generally considered for reciprocating engines given the main function of the engines is for peaking operation.

In terms of retirement, reciprocating engines are a mature technology with well-established market characteristics that influence retirement. The technology's maturity is reflected in its stable operational profile, with no material performance improvements or technological developments anticipated over time. This stability provides operators with predictable asset lifecycles and maintenance requirements, facilitating long-term planning for retirement and replacement strategies.

The retirement process for reciprocating engines mirrors that of conventional gas turbines characterized by relatively straightforward decommissioning procedures and robust secondary markets. The strong resale market for these assets is supported by the robust growth in the reciprocating engine market, driven by rising demand for

[84] **Wärtsilä succeeds in world's first hydrogen blend test - Wärtsilä Energy**

reliable power and increased infrastructure development. This continued market demand stems from their standardized components, widespread availability of technical resources, and applications across various sectors.

3.9.3.1 Summary of changes

Consistent with what has been seen across the thermal technology fleet, costs for reciprocating engine power stations have been seen to increase off the back of increased market demand, heightened activity in power-intensive industries such as data centres, and the ongoing need for peaking and firming technologies to support intermittent renewable generation.

Due to an increase in unit size of the modelled unit from 17.6 to 18.4 MW, the total hypothetical project size has increased from 211 MW (gross) to 221 MW (gross).

3.9.4 Selected hypothetical project

The table below outlines the configuration for a typical NEM-connected reciprocating engine. This scenario has been selected based on a plausible project for installation in the NEM in 2025 given the above discussion on typical options and current trends.

Table 3.51 Configuration and performance – Reciprocating engines

Item	Unit	Value	Comment
Configuration			
Technology / OEM		Wartsila	MAN Diesel and Rolls Royce Bergen (RRB) also offer comparable engine options
Make model		18V50DF	Including Selective Catalytic Reduction (SCR) for NOx emission control. Dual fuel (gas and liquid fuel (e.g. diesel) operation, with hydrogen readiness (25% blend with natural gas) based on current capability. OEM to be consulted on hydrogen blend operation in this configuration. Natural gas operation with pilot diesel supply is normally used for dual fuel units.
Unit size (Nominal)	MW	18.4	ISO / nameplate rating at generator terminals
Number of units		12	MAN Diesel and Rolls Royce Bergen (RRB) also offer comparable engine options
Performance (Natural gas)			
Total plant size (Gross)	MW	221	25°C, 110 metres, 60%RH
Auxiliary power consumption and losses	%	1.8%	Of base load
Total plant size (Net)	MW	217	25°C, 110 metres, 60%RH. Performance on natural gas. No output derate considered for hydrogen blend. OEM to be consulted for performance derate
Seasonal rating – Summer (Net)	MW	217	Derating does not typically occur until temperatures over 38 - 40°C
Seasonal rating – Not Summer (Net)	MW	217	Operating at temperature ranging between 10 – 20ºC
Hydrogen demand at maximum operation	kg/h (HHV)	1284	25% hydrogen
Heat rate at minimum Operation	(GJ/MWh) LHV Net	10.259	25°C, 110 metres, 60%RH. Assuming minimum operation on gas fuel
Heat rate at maximum operation	(GJ/MWh) LHV Net	7.940	25°C, 110 metres, 60%RH. Gas fuel operation
Thermal Efficiency at MCR	%, LHV Net	45.3%	25°C, 110 metres, 60%RH. Gas fuel operation
Heat rate at minimum operation	(GJ/MWh) HHV Net	11.356	25°C, 110 metres, 60%RH. Gas fuel operation

Item	Unit	Value	Comment
Heat rate at maximum operation	(GJ/MWh) HHV Net	8.790	25°C, 110 metres, 60%RH. Gas fuel operation
Thermal Efficiency at MCR	%, HHV Net	40.9%	25°C, 110 metres, 60%RH. Gas fuel operation
Annual Performance			
Average planned maintenance	Days / yr.	2.7	Based on each engine only running 2190 hours per year
Equivalent forced outage rate	%	2%	
Effective annual capacity factor	%	25%	Typical average for current planned firming generation dispatch
Annual generation	MWh / yr.	475,230	Provided for reference based on assumed capacity factor
Annual degradation over design life – Output	%	2%	Assuming straight line degradation
Annual degradation over design life – Heat rate	%	0.05%	Assuming straight line degradation

Table 3.52 Technical parameters and project timeline – Reciprocating engines

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	36	Station ramp rate (all units) under standard operation. Based on OEM data
Ramp down rate	MW / min	36	Station ramp rate (all units) under standard operation. Based on OEM data
Start-up time	Min	10	Standard operation. Based on OEM data. 5-minute fast start is available
Min stable generation	% of installed capacity	40%	Can turn down to 10% on diesel operation. Based on general OEM data
Project timeline			
Time for development	Years	2	Includes pre/feasibility, design, approvals, procurement, etc.
First year assumed commercially viable for construction	Year	2025	-
EPC programme	Years	2- 2.5	-
– Total lead time	Years	1.0	-
– Construction time	Weeks	80	16 months assumed from engines to site to COD
Economic life (Design life)	Years	25	Can be capacity factor dependant
Technical life (Operational life)	Years	40	Will need continual refurbishment after 25 years of life

3.9.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined reciprocating engines.

Table 3.53 Development cost estimates – Reciprocating engines

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW (Net)	2,360	Includes liquid fuel storage (30 hours) and associated infrastructure ~$8m. Relative cost does not include land and development costs.
Total EPC cost	$	512,956,000	-
– Equipment cost	$	359,069,000	Assumed 70% of EPC cost
– Installation cost	$	153,887,000	Assumed 30% of EPC cost
Other costs			
Cost of land and development	$	61,555,000	Assumed 12% of EPC cost. Includes owners costs but excludes interest during construction.
Fuel connection costs (Fixed)	$	23,000,000	-
Fuel connection costs (Variable)	$/km	1,600,000	-
Startup cost			
Fast startup cost	$	245	Based on fuel cost only

3.9.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined reciprocating engine project (Appendix C).

Table 3.54 O&M estimates – Reciprocating engines

Item	Unit	Value	Comment
Fixed O&M cost	$ / MW (Net)	36,000	Based on preparation of a high-level bottom-up estimate
Variable O&M cost	$ / MWh (Net)	9	Based on preparation of a high-level bottom-up estimate
Total annual O&M cost	$ MW (Net)	12,089,070	-

3.9.7 Retirement cost estimates

Retirement estimates for the reciprocating engine scenario reflective of NEM-connected dual fuel reciprocating engine generation plants are outlined below.

Table 3.55 Retirement estimate – Reciprocating engines

Item	Unit	Value	Comments
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	64,500	Based on preparation of a high-level bottom-up estimate
Disposal costs	$/MW (Net)	22,000	Based on preparation of a high-level bottom-up estimate
Recycling costs	$/MW (Net)	(28,500)	Based on preparation of a high-level bottom-up estimate
Total retirement costs	$/MW (Net)	58,000	Based on preparation of a high-level bottom-up estimate

3.10 Coal fired power plants

3.10.1 Overview

Coal fired power plants are currently the dominant source of electricity generation in Australia, providing 46% of electricity generation for the NEM in 2024/2025[85]. In the NEM there are approximately 21,255 MW of coal fired units installed across all coal power stations in QLD, NSW and VIC. The unit sizes, which are often installed in multiples, range from 280 MW to 720 MW[86] and use a range of coal types from low grade brown coal through to black coal[87].

Coal fired (thermal) power plants operate by burning coal in a large industrial boiler to generate high pressure, high temperature steam. High pressure steam from the boiler is passed through the steam turbine generator where the steam is expanded to drive the turbine linked to a generator to produce the electricity. This process is based on the thermodynamic Rankine cycle.

Most coal fired power plants are typically classified as sub-critical[88] with several classified as super-critical[89]. Recent development around the world has seen growth of ultra-super-critical[90] and advanced ultra-super-critical plants depending on the steam temperature and pressure. Over time advancements in the construction materials have permitted higher steam pressures and temperatures leading to increased plant efficiencies and overall generation unit capacity[91].

3.10.2 Typical options

The coal fired power stations installed on the NEM utilise either sub-critical or super-critical pulverised coal (PC) technology, which is an established, proven technology used for power generation throughout the world for decades.

The latest super-critical coal fired units installed in Australia can produce super-critical steam conditions in the order of 24 MPa and 566°C and typically used with unit sizes of about 425 MW. Internationally, more recent coal fired units have been installed with ever increasing steam temperature and pressure conditions to achieve higher efficiencies.

Current OEMs are proposing super-critical units in line with the following:

– Ultra-super-critical (USC), with main steam conditions in the order of 27 MPa and 600°C
– Advanced ultra-super-critical (AUSC), with main steam conditions in the order of 33 MPa and 660°C.

Ultra-super-critical coal fired units are typically installed with capacities of 600 MW – 1,000 MW each. An advanced ultra-super-critical power station with the above main steam conditions is yet to be constructed internationally, however, are currently being proposed by a number of OEMs globally. No ultra-super-critical or advanced ultra-super-critical coal fired units are installed or planned in Australia at present.

CCS has not been adopted in Australia to any power station at a commercial scale. There have been a number of pilot plants, but none have been developed further. It is common knowledge that sub-critical coal technology produces the most CO_2 emission as a result of its lower efficiency. Super-critical coal power stations have generally ~2% better efficiency and therefore produce less CO_2/MWh than sub-critical power stations. Ultra super-critical is a technology having the highest plant efficiency of all coal technologies. Efficiency for ultra-super-critical technology is ~ 2% better than for Super-critical and therefore has the lowest CO_2 emissions of all the coal burning technologies in a Rankine Cycle.

[85] **www.nemondemand.com.au**
[86] Eraring Power Station unit size
[87] **https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information**
[88] Sub- Critical pressures are steam pressures between 60 and 160 bar and temperatures between 440-550 deg C
[89] Super-critical pressures are steam pressures between 180 and 220 bar and temperatures beyond 580-620 deg C.
[90] Ultra-super-critical pressures are steam pressures of beyond 240 Bar and steam temperatures beyond 700 deg C.
[91] Ultra super-critical thermal power plant material advancement: A review, Dheeraj Shankarrao Bhiogade, Science Direct, Vol 3 September 2023, 100024

A number of coal fired power stations overseas have added a CCS plant but mainly to redirect the CO_2 captured for oil production enhancement in oil wells (not strictly sequestration).

3.10.3 Recent trends

The last coal fired power stations to be installed in Australia were Kogan Creek Power Station in Queensland, which was commissioned in 2007, and Bluewaters Power Station in Western Australia, which was commissioned in 2009. Since the commissioning of Bluewaters PowerStation there has been very little focus on further coal fired development in Australia.

In March 2017, Hazelwood Power Station ceased operation in Victoria and AGL's Liddell Power Station in NSW was retired in April 2023. More recently, alternative generation technologies have become more prevalent with the energy transition towards net zero, focussed on adopting non-coal technologies for replacing lost capacity from planned coal fired plant closures. Some existing coal fired plants have considered a fuel switch from coal for potential repurposing of the generation plant.

Internationally, particularly in Asia, there has been extensive development of new large coal fired power stations to provide for growing electricity demand (e.g. Van Phong 1 Coal Fired Power Plant, 2 x 660 MW in Vietnam has achieved commercial operation in March 2024; Vung Ang II Thermal Power Plant, 2 x 665 MW in Vietnam is expected to be operational in the third quarter of 2025). These plants are commonly being installed utilising super-critical or ultra-super-critical steam conditions which offer improved plant efficiencies and reduced whole of life costs.

However, government policies in many countries in Asia have recently slowed the growth of coal fired stations barring already approved power station developments, investors are favouring alternative renewable generation and have shown less appetite for investment in new coal fired power station development.

In Australia, the only coal fired development in progress is understood to be the Collinsville coal fired power station proposed by Shine Energy[92] (3 x 315 MW totalling 1,000 MW). This project has completed the definitive feasibility stage 1 and is believed to be at feasibility stage 2. The company website suggests construction duration will be 3 years and given that the stage 2 feasibility study is expected to be completed by the end of 2025, the plant is not likely to be commissioned until the end of 2029.

In recent years, there has been a significant retreat regarding development activities relating to coal fired power plants even as existing assets near end-of-life. There are fewer OEMs that are willing to offer coal fired power plant and equipment for coal fired power plants in Australia.

The following sections present cases for practical and hypothetical plant options based on Black Coal Advanced USC for a new build.

3.10.3.1 Summary of changes

The 2024 report estimated a relative CAPEX cost of \$5,031/kW for AUSC without CCS, \$8,211/kW with 50% capture and \$10,219/kW with 90% capture, whereas this 2025 report estimates \$6,030/kW without CCS, \$9,240/kW with 50% capture and \$10,940/kW with 90% capture.

The scale of capital cost increase seen for coal fired generation is broadly consistent with the trend seen across all thermal generation technologies, which is credited to a combination of increased demand (in particular in steam turbines, large power equipment, and associated skills and trades) and general cost increases due to global supply chain factors. While changes are specific to technology and application, increases across thermal generation projects (including coal and gas fired generation) have increased materially, with increases of up to 30% being reported across industry publications and benchmarks.

The 2024 report assumed land and development costs were 20% of CAPEX, whereas this Report assumes 15% of CAPEX. This has resulted in a material difference (i.e. ~\$675M in 2024 and ~\$608M in 2025 for AUSC without CCS).

[92] **www.shineenergy.com.au**

3.10.4 Black coal ultra super-critical

3.10.4.1 Selected hypothetical project

Table 3.56 Configuration and performance – Black coal ultra super-critical

Item	Unit	AUSC without CCS	AUSC with CCS (90% Capture)	AUSC with CCS (50% Capture)	Comment
Configuration					
Technology	-	AUSC	AUSC	AUSC	With natural draft cooling towers
Carbon Capture & Storage	-	No	Yes	Yes	90% capture efficiency assumed. SCR & FGD included with CCS option
Make Model	-	Western OEM	Western OEM	Western OEM	Western includes US, European, Japanese or Korean OEMs
Unit Size (Nom)	MW	700	700	700	ISO Rating
No. of Units		1	1	1	-
Steam Pressures (main/reheat)	MPa	33.5/6.2	33.5/6.2	33.5/6.2	-
Steam Temperatures (main/reheat)	Deg C	650/670	650/670	650/670	-
Condenser Pressure	kPa abs	6	6	6	-
Performance					
Total plant size (gross)	MW	700	700	700	25deg C, 110 metres, 60% RH
Auxiliary Power consumption	%	4.1	17.5	12.5	Assumed steam driven BFP, natural draft CT.
Total Plant size (Net)	MW	671	577	612	25deg C, 110 metres, 60% RH
Seasonal Rating Summer (Net)	MW	658	566	600	35deg C, 110 metres, 60% RH
Seasonal Rating Not Summer (Net)	MW	673	582	616	15deg C, 110 metres, 60% RH
Heat Rate @ minimum operation	GJ/MWh (HHV net)	10,170	11,640	10,110	25deg C, 110 metres, 60% RH
Heat Rate @ maximum operation	GJ/MWh (HHV net)	8,550	11,990	9,890	25deg C, 110 metres, 60% RH
Thermal Efficiency @ MCR	% (HHV net)	42.1	30.0	36.4	25deg C, 110 metres, 60% RH
Annual Performance					
Average Planned Maintenance	Days/yr	10.5	10.5	10.5	Based on 14 day minor outage every 2 yrs & 28 day major outage every 4 yrs
Equivalent Forced Outage	%	4	4	4	-
Effective Annual availability Factor	%	90	90	90	-
Annual Generation	MWh/yr	5,483,145	4,714,311	5,000,275	Assumed 97% CF and 1.04 EFOR

Item	Unit	AUSC without CCS	AUSC with CCS (90% Capture)	AUSC with CCS (50% Capture)	Comment
Annual Degradation over Design Life – heat rate	%	0	0	0	Assumed that any degradation is restored during Overhauls
Annual Degradation over Design Life - output	%	0.2	0.2	0.2	Assuming SL Degradation

Table 3.57 Technical parameters and project timeline – Black coal ultra super-critical

Item	Unit	AUSC without CCS	AUSC with CCS (90% Capture)	AUSC with CCS (50% Capture)	Comment
Technical Parameters					
Ramp up rate	MW/min	20	20	20	Based on 3%/min standard operation
Ramp down rate	MW/min	20	20	20	Based on 3%/min standard operation
Start up time	minutes	Cold 444 Warm: 264, Hot: 60	Cold 444 Warm: 264, Hot: 60	Cold 444 Warm: 264, Hot: 60	Standard operation
Min Stable Generation	% of installed capacity	30	30	30	Without oil support
Project Timeline					
Time for Development	Years	4 - 5	4 - 5	4 - 5	Includes pre-feasibility, design, approvals etc. (assumes no delay in the approvals phase)
First year assumed commercially viable for construction	Year	2025	2025	2025	-
EPC Program for Construction	Years	4 - 5	4 - 5	4 - 5	From NTP to COD
Total Lead Time	Years	2.5	2.5	2.5	Time from NTP to ST on site
Construction time	Weeks	104	104	104	Time from ST on site to COD
Economic Life (Design Life)	Years	30	30	30	-
Technical Life (Operational Life)	Years	50	50	50	-

3.10.4.2 Development cost estimates – Black coal ultra super-critical

The following table provides CAPEX cost estimates for the defined black coal ultra super-critical projects.

Table 3.58 Development cost estimates – Black coal ultra super-critical

Item	Unit	AUSC without CCS	AUSC with CCS (90% Capture)	AUSC with CCS (50% Capture)	Comment
CAPEX – EPC cost					
Relative Cost	$/kW	6,030	10,940	9,240	Excludes owners costs.
Total EPC Cost	$	4,053,000,000	6,492,800,000	5,792,400,000	

Item	Unit	AUSC without CCS	AUSC with CCS (90% Capture)	AUSC with CCS (50% Capture)	Comment
Equipment Cost	$	1,621,200,000	1,621,200,000	1,621,200,000	Assumed 40% of EPC cost without CCS
Construction Cost	$	2,431,800,000	2,431,800,000	2,431,800,000	Assumed 60% of EPC cost without CCS
Carbon Capture Cost		0	2,439,800,000	1,739,300,000	-
Other Costs					
Cost of land and development	$	607,950,000	973,920,000	868,860,000	Assumed 15% of CAPEX. Includes owners costs but excludes interest during construction.
Fuel Connection costs	$/km	2,280,000	2,280,000	2,280,000	Assumed single track rail line fuel supply in the order of 50 to 100 km in length
CO2 Storage Cost	$/t CO2	0	18.5	18.5	Based on Rubin E.S et al, 2015[93] and adjusted to match report basis. Range of 12 – 25, with the mid-point taken for CSS reporting.
CO2 Transport	$/t CO2/km	N/A	0.1096	0.1096	CO2 transport cost varies on a project by project basis. Figures shown refer to Rubin, E.S., et al (2015)[94] which have been escalated by 2% from the 2024 report[95].
Start up costs	$	146,500	146,500	146,500	2024 figures[96] escalated by 2% and rounded

3.10.4.3 O&M cost estimates – Black coal ultra super-critical

The following table provides fixed, variable and total annual O&M cost estimates for the defined black coal ultra super-critical project.

Table 3.59 O&M cost estimates – Black coal ultra super-critical

Item	Unit	AUSC without CCS	AUSC with CCS (90% Capture)	AUSC with CCS (50% Capture)	Comment
Fixed O&M cost	$/MW (Net)	66,200	96,800	86,500	2024 figures[97] escalated by 2% and rounded
Variable O&M cost	$/MWh (Net)	5	9	8	2024 figures[98] escalated by 2% and rounded
Total annual O&M cost	$	70,600,000	98,300,000	90,700,000	2024 figures[99] escalated by 2% and rounded

[93] Rubin, E.S., et al., The cost of CO2 capture and storage. Int. J. Greenhouse Gas Control (2015),
[94] Rubin, E.S., et al., The cost of CO2 capture and storage. Int. J. Greenhouse Gas Control (2015),
[95] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024
[96] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024
[97] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024
[98] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024
[99] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024

3.10.4.4 Retirement cost estimates – Black coal ultra super-critical

Retirement costs for the defined black coal ultra super-critical projects are outlined in the table below.

Table 3.60 Retirement estimate – Black coal ultra super-critical

Item	Unit	AUSC without CCS	AUSC with CCS (90% Capture)	AUSC with CCS (50% Capture)
Decommissioning & demolition costs	$/MW (Net)	117,000	190,000	180,000
Rehabilitation costs	$/MW (Net)	120,000	192,000	184,000
Disposal costs	$/MW (Net)	52,000	81,000	76,000
Recycling cost	$/MW (Net)	(40,000)	(58,000)	(58,000)
Total retirement costs	$/MW (Net)	249,000	405,000	382,000

The following sections presents the case for O&M and retirement costs for black coal sub-critical, black coal super-critical and brown coal sub-critical.

3.10.5 Black coal sub-critical

The following sub-sections provide details of O&M and retirement cost for black coal sub-critical technology.

3.10.5.1 O&M cost estimates - Black coal sub-critical

The following table provides fixed, variable and total annual O&M cost estimates for black coal sub-critical technology.

Table 3.61 O&M estimates – Sub-critical black coal fired power plants

Item	Unit	Small w/out CCS	Small with CCS	Large w/out CCS	Large with CCS	Comment
Fixed O&M cost	$ / MW (Net)	38,000	65,000	28,000	46,000	Based on preparation of a high-level bottom-up estimate
Variable O&M cost	$ / MWh (Net)	7	18	8	18	Based on preparation of a high-level bottom-up estimate
Total annual O&M cost	$ MW (Net)	32,615,800	72,419,200	51,427,520	124,021,920	Calculated on the basis of a CF of 90%

3.10.5.2 Retirement cost estimates - Black coal sub-critical

Retirement costs for the defined sub-critical black coal fired power plants are outlined in the table below.

Table 3.62 Retirement estimate – Sub-critical black coal fired power plants

Item	Unit	Small w/o CCS	Small with CCS	Large w/o CCS	Large with CCS
Decommissioning & demolition costs	$/MW	126,000	203,000	117,000	187,000
Rehabilitation costs	$/MW	110,000	176,000	119,000	191,000
Disposal costs	$/MW	51,000	82,000	50,000	80,000
Recycling cost	$/MW	(32,000)	(42,000)	(32,000)	(38,000)
Total retirement costs	$/MW	255,000	419,000	254,000	420,000

3.10.6 Black coal super-critical

The following sub-sections provide details of O&M and retirement cost for black coal super-critical technology.

3.10.6.1 O&M cost estimates - Black coal super-critical

The following table provides fixed, variable and total annual O&M cost estimates for black coal super-critical technology.

Table 3.63 O&M estimates – Super-critical black coal fired power plants

Item	Unit	Small w/out CCS	Small with CCS	Large w/out CCS	Large with CCS	Comment
Fixed O&M cost	$ / MW (Net)	49,000	72,000	52,000	72,000	Based on preparation of a high-level bottom-up estimate
Variable O&M cost	$ / MWh (Net)	8	18	8	18	Based on preparation of a high-level bottom-up estimate
Total annual O&M cost	$ MW (Net)	39,225,200	74,869,200	75,947,520	141,181,920	Based on using a CF of 90%

3.10.6.2 Retirement cost estimates - Black coal super-critical

Retirement costs for the defined super-critical black coal fired power plants are outlined in the table below.

Table 3.64 Retirement estimate – Super-critical black coal fired power plants

Item	Unit	Small w/o CCS	Small with CCS	Large w/o CCS	Large with CCS
Decommissioning & demolition costs	$/MW (Net)	126,000	200,000	117,000	186,000
Rehabilitation costs	$/MW (Net)	110,000	174,000	119,000	189,000
Disposal costs	$/MW (Net)	51,000	81,000	50,000	80,000
Recycling costs	$/MW (Net)	(37,000)	(50,000)	(39,000)	(55,000)
Total retirement costs	$/MW (Net)	250,000	405,000	247,000	400,000

3.10.7 Brown coal sub-critical

The following sub-sections provide details of O&M and retirement cost for brown coal sub-critical technology.

3.10.7.1 O&M cost estimates - Sub-critical brown coal fired power plants

The following table provides fixed, variable and total annual O&M cost estimates for brown coal sub-critical technology.

Table 3.65 O&M estimates – Sub-critical brown coal fired power plants

Item	Unit	Small w/out CCS	Small with CCS	Large w/out CCS	Large with CCS	Comment
Fixed O&M cost	$ / MW (Net)	45,000	78,000	63,000	88,000	Based on preparation of a high-level bottom-up estimate
Variable O&M cost	$ / MWh (Net)	8	19	8	19	Based on preparation of a high-level bottom-up estimate
Total annual O&M cost	$ MW (Net)	37,825,200	79,728,600	83,207,520	156,945,360	Based on using a CF of 90%

3.10.7.2 Retirement cost estimates - Sub-critical brown coal fired power plants

Retirement costs for sub-critical brown coal power stations that are reflective of NEM based generating plants are outlined below.

Table 3.66 Retirement estimate – Sub-critical brown coal fired power plants

Item	Unit	Small w/o CCS	Small with CCS	Large w/o CCS	Large with CCS
Decommissioning & demolition costs	$/MW (Net)	168,000	202,000	164,000	213,000
Rehabilitation costs	$/MW (Net)	146,000	206,000	159,000	206,000
Disposal costs	$/MW (Net)	68,000	87,000	69,000	90,000
Recycling costs	$/MW (Net)	(32,000)	(32,000)	(37,000)	(37,000)
Total retirement costs	$/MW (Net)	350,000	463,000	355,000	472,000

3.11 Open cycle & CCGT gas turbine

3.11.1 Overview

Gas turbines are one of the most widely used power generation technologies today. The technology is well proven and is used in both Open Cycle Gas Turbines (OCGT) and CCGT configurations. Gas turbines are classified into two main categories – aero-derivatives and industrial turbines. Both find applications in the power generation industry, although for baseload applications, industrial gas turbines are preferred. Conversely, for peaking applications, the aero-derivative is more suitable primarily due to its faster start up time. Within the industrial turbines class, gas turbines are further classified as E – class, F – class and H (G/J) – class turbines. This classification depends on their development generation and the associated advancement in size and efficiencies. Gas turbines can operate on natural gas, hydrogen, and liquid fuel (and blends) along with associated blends.

Gas turbines utilize synchronous generators, which provide relatively high fault current contribution in comparison to other technologies and accordingly can support network strength. Synchronous condenser mode operation using the generator is also an option able to be offered depending on OEM to provide additional network system strength when the gas turbine is not in operation.

Gas turbines currently provide high rotating inertia to the NEM which is a valuable feature that increases the NEM frequency stability.

3.11.2 Typical options

3.11.2.1 **OCGT**

An OCGT plant consists of a gas turbine connected to an electrical generator via a shaft. A gearbox may be required depending on the RPM of the gas turbine and the grid frequency. The number of gas turbines deployed in an OCGT plant will depend mainly on the output and redundancy levels required. OCGT plants are typically used to meet peak demand. Both industrial and aero-derivative gas turbines can be used for peaking applications. However, aero-derivatives have some advantages that make them more suitable for peaking applications, including:

– Faster start-up time
– Operational flexibility i.e. quick ramp up and load change capability
– No penalties on O&M for normal operations (mid-merit) i.e. increased maintenance requirements for high number of starts in peaking mode.

Irrespective of the benefits of aeroderivative gas turbines, industrial gas turbines have also been widely used in OCGT mode. Traditionally, E or D class machines are used in OCGT mode. Occasionally F or H class machines are used in OCGT applications. Examples where F class machines are used in OCGT configuration in Australia include:

– Mortlake Power Station (operational),
– Tallawarra B Power Station (operational) and
– Kurri Kurri Power Station (under construction).

Ultimately, the choice of gas turbine will depend on many factors including the operating regime of the plant, size, and more importantly, life cycle cost.

3.11.2.2 **CCGT**

A CCGT consists of a gas turbine/generator connected to a heat recovery steam generator that produces high pressure steam for a condensing steam turbine generator. The number of gas turbines deployed in a CCGT plant will depend on the output required and the redundancy level needed. CCGT plant are typically used to meet base load or mid-merit loads. Typical CCGTs installed in the NEM are:

– Tallawarra A (NSW) (operational)
– Tamar Valley CCGT (Tasmania) (operational)
– Townsville CCGT (QLD) (operational)

3.11.3 Recent trends

The growing deployment of renewable energy generation has opened opportunities for capacity firming solutions, with gas-fired power generation being a key component. In this market OCGT and reciprocating engines are important competitors and have seen a strong increase in market activity and interest, which in turn has driven an increase in costs and lead times for this equipment. Given the need for flexibility in firming plants (and reduced importance of fuel efficiency due to lower capacity factors), CCGTs are not typically targeted for these projects and are considered primarily for baseload or mid-merit applications, which have not seen the same increase in interest.

It is possible that the closure of coal fired power stations in the coming years will provide an opportunity for new CCGT plants or increased capacity factor in existing facilities, however this gap may be more readily addressed through a combination of intermittent renewable energy, energy storage, and peaking gas power stations. At the current time, interest in gas fired generation remains focused on open cycle turbines and reciprocating gensets.

Advancements in gas turbine technology are emphasising low-emission solutions, including the integration of hydrogen, either through blending or complete hydrogen combustion, as well as other renewable fuels such as biomethane. It is anticipated that all new gas turbine projects will incorporate provisions and capabilities for hydrogen blending and eventual conversion to hydrogen combustion as the hydrogen supply becomes more accessible.

Most gas turbines have the ability to operate with a percentage of hydrogen in the fuel mix (20-35% of Hydrogen by Volume). A typical blend percentage of around 30% is offered by most OEMs (depending on the unit), whilst some units can accept very high percentages of hydrogen in the fuel (95%+). Currently, few gas turbines can operate on 100% hydrogen (with diffusion combustion system and diluent injection). This is expected to change dramatically over the coming years with newly designed micro/multi-nozzle combustion systems being developed, tested, and implemented to cater for hydrogen, expected by 2030.

Depending on the hydrogen percentage, modifications to the gas turbine may range from updating controls and fuel nozzles to installing a new combustion system with updated piping, valves, safety features, and detection systems. Retirement costs will be higher for plants using more than 30-40% hydrogen compared to those using only natural gas.

Hydrogen ready OCGT projects have been considered for the hypothetical projects. Hydrogen supply would be either via gas network as a blend or could be via dedicated renewable hydrogen supply from an electrolysis plant. Given the current status of hydrogen blending in gas networks planned in Australia based on current projects under development is likely to lead to open cycle gas turbine plants using a blend of hydrogen with natural gas.

Current trends in Australia[100] suggest that deployment of hydrogen blending will be slower than originally anticipated with facilities such as EnergyAustralia’s Tallawarra B and Snowy Hydro’s Kurri Kurri facility both expecting delays to the introduction of hydrogen blended fuel. Whilst equipment capabilities exist, the blend percentage is also expected to be influenced by the availability of hydrogen and the blend design capabilities in existing or new gas pipelines adopted.

[100] **1121953355_20260903.pdf**

Alternatively, a hydrogen ready gas turbine plant could be supplied from a dedicated hydrogen electrolysis plant using renewable energy supply and blended with a natural gas pipeline supply to the site. In this case, OCGT plant capacity would be based on hydrogen production from a suitable sized electrolysis plant and operated in peaking duty using hydrogen supply with storage to meet the hydrogen demand.

3.11.3.1 Summary of changes

Consistent with what has been seen across the thermal technology fleet, costs for gas turbine power stations have been seen to increase on the back of increased market demand, heightened activity in power-intensive industries such as data centres, and the ongoing need for peaking and firming technologies to support intermittent renewable generation. Aeroderivative gas turbines in particular, with their improved flexibility and tolerance for increase frequency of starts, have seen a sharp increase in interest and demand.

While year-on-year cost increases are common, the cumulative effect of this heighted market demand and global supply chain factors have resulted in a step change in cost expectations across the thermal fleet, with material cost increases of up to 30% being reported across industry publications and benchmarks. Operating and maintenance costs have increased in a similar proportion, noting that operating costs are heavily impacted by assumptions on operating modes and start frequencies, and can vary significantly between turbine manufacturers and models.

3.11.4 Selected hypothetical project - OCGT

The following tables outline the technical parameters for the hypothetical projects (multiple small and large aeroderivative Dry Low NOx (DLN) gas turbines using 35% (by Vol) hydrogen blend with natural gas (based on current capability) and a small and large industrial gas turbine using a 10-15% (by Vol) hydrogen blend) using natural gas, both projects with liquid fuel (e.g. diesel) back up. The hypothetical project has been selected based on what is envisaged as plausible projects for development in the NEM in 2025 given the above discussion on typical options and current trends.

Table 3.67 Configuration and performance – OCGT

Item	Unit	Small Aero derivative	Large Aero derivative	Small Industrial GT	Large Industrial GT	Comment
Technology		Small Aero-derivative	Large Aero-derivative	Small Industrial	Industrial (F-Class)	-
Make model		LM2500 (GE)	LM6000 (GE)	SGT-800	GE 9F.03	Small Aero GTs − Typical model planned in Australian project (LM2500), assumes Dry Low NOx combustion system for NOx emission control with hydrogen blending. Larger LM6000 PC/PG unit with SAC combustion system is typical for NOx control. Small industrial GT – is a typical small GT Large industrial GT − Smallest F-Class unit available
Unit size (Nominal)	MW	34	48	58	268	% Output derate for 35% hydrogen to be confirmed with OEM for small GT. No derate considered. ISO / nameplate rating, GT Pro. Performance on natural gas

Item	Unit	Small Aero derivative	Large Aero derivative	Small Industrial GT	Large Industrial GT	Comment
NG/H2 blend	% H2 (by Vol)	35	35	10-15	10	Industry trends suggest 10% H2 could be common for industrial GT
Number of units		6	4	4	1	-
Performance (Site Conditions, 25 deg C, 110 m, 60% RH)						
Total plant size (Gross)	MW	191	178	216	251	Gross at site conditions
Auxiliary power consumption and losses	%	2%	2%	2%	2%	Estimated consumption for most installations
Total plant size (Net)	MW	186	174	211	246	Net at site conditions
Seasonal rating – Summer (Net)	MW	175	163	198	232	Net at high ambient temperature for 30 deg C (W/O evap cooling)
Seasonal rating – Not Summer (Net)	MW	197	184	222	259	Net at low ambient temperature for 10 deg C
Min Rating of MCR	%	30%	20%	30%	50%	Min OEM recommendations
Rating At Min MCR (Net)	MW	56	35	63	123	At site conditions
Heat rate at minimum operation	GJ/MWh LHV net	14.6	14.0	15.9	16.4	At site conditions
Heat rate at maximum operation	GJ/MWh LHV net	9.6	9	9.3	9.8	At site conditions
Efficiency at MCR	% LHV net	37.6%	39.9%	38.7%	36.8%	At site conditions
Heat rate at minimum operation	GJ/MWh HHV net	16.2	15.5	17.4	18.2	At site conditions
Heat rate at maximum operation	GJ/MWh HHV net	10.6	10.0	10.3	10.8	At site conditions
Efficiency at MCR	% HHV net	34.0%	36.0%	35.0%	33.2%	At site conditions
Annual performance						
Average planned Maintenance	Days/yr	7	7	7	7	Based on 3-4 days for a minor overhaul plus 2-3 weeks every 6 years.
Equivalent Forced Outage Rate	%	2-3%	2-3%	2-3%	2-3%	Indicative
Effective annual capacity factor	%	20%	20%	20%	20%	This figure can be as low as 2% and as high as a mid-merit Power Plant of ~35%

Item	Unit	Small Aero derivative	Large Aero derivative	Small Industrial GT	Large Industrial GT	Comment
Annual generation	MWh / year	325,872	304,848	369,672	430,992	EFOR is considered in this evaluation using an EFOR of 2.5%

Table 3.68 Technical parameters and project timeline – OCGT

Item	Unit	Small Aero derivative	Large Aero derivative	Small Industrial GT	Large Industrial GT	Comment
Technical Parameters						
Ramp up rate	MW / min (per GT)	20	25	25	22	MW change per minute per GT
Ramp down rate	MW / min	20	25	25	22	-
Start-up time	Min	5	5	10	20	From cold start
Min stable generation	% of installed capacity	50	50	50	50	-
Project timeline						
Time for development	Years	1.5	1.5	2	2	-
Economic life (Design life)	Years	25	25	25	25	-
Technical life (Operational life)	Years	40	40	40	40	-

3.11.5 Development cost estimates – OCGT

The following table provides CAPEX cost estimates for the defined OCGT projects.

Table 3.69 Development cost estimates – Open cycle gas turbine

Item	Unit	Small Aero derivative	Large Aero derivative	Small Industrial GT	Large Industrial GT	Comment
CAPEX – EPC cost						
Relative cost	$/kW (Net)	2,600	3,000	2,000	1,600	Excludes Owners Cost
Total EPC cost	$	479,300,000	519,900,000	426,700,000	387,500,000	
– Equipment cost	$	335,500,000	363,900,000	298,700,000	271,250,000	Assumed 70% of EPC
– Construction cost	$	143,800,000	156,000,000	128,000,000	116,250,000	Assumed 30% of EPC
Other costs						
Cost of land and development	$	57,500,000	62,400,000	51,200,000	46,500,000	Assumed 12% of EPC. Includes owners cost but excludes interest during construction.
Fuel connection costs (Fixed)	$	23,000,000	23,000,000	23,000,000	23,000,000	This is indicative. Escalated from 2024 report. Fuel connection cost varies on a project-by-project basis.

Item	Unit	Small Aero derivative	Large Aero derivative	Small Industrial GT	Large Industrial GT	Comment
Fuel connection costs (Variable)	$/km	1,600,000	1,600,000	1,600,000	1,600,000	
Gas compressors	$	Included in total costs above.	Included in total costs above.	Included in total costs above.	Included in total costs above.	
Gas storage		Not included	Not included	Not included	Not included	Assumed to be outside of scope of power station.
Startup costs						
Fast start up cost	$	-	-	-	-	Start-up costs are built into O&M figures based on technology capability.
First Year Assumed Commercially Viable for construction		2025	2025	2025	2025	

3.11.6 O&M estimates – OCGT

The following table provides fixed, variable and total annual O&M cost estimates for the defined OCGT project.

Table 3.70 O&M estimate – OCGT[101]

Item	Unit	Small Aero derivative	Large Aero derivative	Small Industrial GT	Large Industrial GT	Comment
Fixed O&M cost	$/MW (Net)	29,000	26,000	30,000	23,000	Based on preparation of a high-level bottom-up estimate
Variable O&M cost	$/MWh (Net)	10	10	11	11	Based on preparation of a high-level bottom-up estimate
Total annual O&M cost	$/MW (Net)	$8,652,700	$7,572,500	$10,396,400	$10,398,912	-

3.11.7 Retirement cost estimates - OCGT

Retirement costs for OCGT technology scenarios (small & large Aeroderivative and small & large Industrial gas turbines) reflective of NEM-connected gas generating plants are outlined below.

Table 3.71 Retirement estimate – OCGT

Item	Unit	Small Aero (6xLM2500, Net Output 186MW)	Large Aero (4xLM6000, Net Output 174MW)	Small Industrial (4xSTG800, Net Output 211MW)	Large Industrial (1xGE9F.03, Net Output 246MW)
Decommissioning & demolition costs	$/MW	20,500	20,500	18,500	22,000
Rehabilitation costs	$/MW	27,000	27,000	24,500	26,000
Disposal costs	$/MW	7,500	7,500	7,000	7,500
Recycling costs	$/MW	(24,000)	(18,000)	(12,000)	(18,500)

[101] Based on 20% capacity factor

Item	Unit	Small Aero (6xLM2500, Net Output 186MW)	Large Aero (4xLM6000, Net Output 174MW)	Small Industrial (4xSTG800, Net Output 211MW)	Large Industrial (1xGE9F.03, Net Output 246MW)
Total retirement costs	$/MW	31,000	37,000	38,000	37,000

3.11.8 Selected hypothetical project – CCGT

Table 3.72 Configuration and performance – CCGT

Item	Unit	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
Configuration					
Technology		CCGT	CCGT	CCGT	With mechanical draft cooling tower.
Carbon capture and storage		No	Yes	Yes	-
Make model		GE 9F.03	GE 9F.03	GE 9F.03	Smallest model available selected.
Unit size (Nominal)	MW	405	405	405	OEM Rating
Number of units		1 GT + 1 ST	1 GT + 1 ST	1 GT + 1 ST	HP pressure – 165 97 bar HP temperature – 582 566°C Reheat temperature – 567 497°C
Performance (Natural gas)(@ Site Conditions of 25 Deg C and 110 metres and 60% RH)					
Total plant size (Gross)	MW	380	352	365	At site conditions
Auxiliary power consumption and losses	%	3	9	7	At site conditions
Total plant size (Net)	MW	370	320	338	At site conditions
Seasonal rating – Summer (Net)	MW	348	301	318	At site conditions, hot ambient temperature of 30 deg C
Seasonal rating – Not Summer (Net)	MW	389	334	354	At site conditions, cold ambient temperature of 10 deg C
Rating At Min MCR (Net)	MW	218	190	202	At site conditions
Heat rate at minimum operation	(GJ/MWh) LHV Net	7.47	8.29	7.76	At site conditions
Heat rate at maximum operation	(GJ/MWh) LHV Net	6.38	7.41	7.00	At site conditions
Thermal Efficiency at MCR	%, LHV Net	55.2	48.6	51.2	At site conditions
Thermal Efficiency at MCR	%, HHV Net	50.9	43.9	46.4	At site conditions
Annual performance					
Average planned maintenance	Days / year	12.8	12.8	12.8	Typical
Equivalent forced outage rate	%	3.5	3.5	3.5	Typical
Effective annual capacity factor	%	60	60	60	Assumed
Annual generation	MWh / year	1,949,135	1,678,240	1,777,054	

Item	Unit	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
Annual degradation over design life – Output	%	0.2	0.2	0.2	Typical
Annual degradation over design life – Heat rate	%	0.12	0.12	0.12	Typical

Table 3.73 Technical parameters and project timeline – CCGT

Item	Unit	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
Technical parameters					
Ramp up rate	MW / min (per GT)	22	22	22	Standard Operation
Ramp down rate	MW / min	22	22	22	Standard Operation
Start-up time	Min	Cold: 145 min Warm: 115 Hoy: 30	Cold: 145 min Warm: 115 Hoy: 30	Cold: 145 min Warm: 115 Hoy: 30	Standard Operation
Min stable generation	% of installed capacity	46%	46%	46%	Can vary between GT models. 46% equates to 35% GT load.
Project timeline					
Time for development	Years	2-3	3	3	Includes prefeasibility, design, approvals etc.
Economic life (Design life)	Years	25	25	25	
Technical life (Operational life)	Years	40	40	40	Contingent on carrying out the necessary upgrades and refurbishments

3.11.9 Development cost estimates – CCGT

The following table provides CAPEX cost estimates for the defined CCGT projects.

Table 3.74 Development cost estimates – Combined cycle gas turbine

Item	Unit	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
CAPEX – EPC cost					
Relative cost	$/kW (Net)	2,230	6,100	5,200	Net basis. From GTPro. Does not include land and development costs.
Total EPC cost	$	824,900,000	1,989,300,000	1,786,470,000	From GTPro
– Equipment cost	$	577,400,000	577,400,000	577,400,000	From GTPro. 70% EPC cost without CCS
– Construction cost	$	247,500,000	247,500,000	247,500,000	From GTPro 30% EPC cost without CCS
– Carbon capture cost	$	0	1,164,400,000	961,570,000	Carbon capture equipment and installation costs
Other costs					

Item	Unit	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
Cost of land and development	$	98,988,000	238,710,000	214,377,000	Cost of land is dependent on power plant region. Assumed 12% of EPC. Includes owners costs but excludes interest during construction
Fuel connection costs (Fixed)	$	23,000,000	23,000,000	23,000,000	This is indicative. Escalated from 2024 report. Fuel connection cost varies on a project-by-project basis
Fuel connection costs (Variable)	$/km	1,600,000	1,600,000	1,600,000	
Gas compressors		Included in total costs above.	Included in total costs above.	Included in total costs above.	
Gas storage		Not included	Not included	Not included	Assumed to be outside of scope of power station.
CO_2 storage cost	$/tonne CO2	N/A	18.5	18.5	CO2 storage cost varies on a project-by-project basis. Range is typically between 12-25. This figure is indicative of the cost and is based on Rubin, E.S., et al (2015)[102]
CO_2 transport	$/tonne CO2/km	N/A	0.1096	0.1096	CO2 transport cost varies on a project-by-project basis. Figures shown refer to Rubin, E.S., et al (2015)[103] which have been escalated by 2% from the 2024 report[104].
Startup cost					
Fast startup costs	$	166,200	166,200	166,200	Figure from 2024 report[105] escalated by 2%

3.11.10 O&M estimates – CCGT

The following table provides fixed, variable and total annual O&M cost estimates for the defined CCGT project.

The variable O&M estimate is based on a mid-merit or baseload style of operation, with no more than 50 starts per year. It is noted that O&M costs are heavily impacted by operating philosophy, and that an increase in frequency of starts may result in a variable O&M fee much higher than what is presented below.

Table 3.75 O&M estimates – CCGT

Item	Unit	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
Fixed O&M cost	$ / MW (Net)	36,000	46,000	44,000	Based on preparation of a high-level bottom-up estimate
Variable O&M cost	$ / MWh (Net)	5	8	7	Based on preparation of a high-level bottom-up estimate
Total annual O&M cost	$ (Net)	23,066,000	28,146,000	27,311,000	

102 Rubin, E.S., et al., The cost of CO2 capture and storage. Int. J. Greenhouse Gas Control (2015),
103 Rubin, E.S., et al., The cost of CO2 capture and storage. Int. J. Greenhouse Gas Control (2015),
104 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024
105 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024

3.11.11 Retirement cost estimates

Table 3.76 presents retirement cost estimates for CCGT technology scenarios (CCGT with and without CCS) reflective of NEM-connected CCGT facilities.

Table 3.76 Retirement estimate – CCGT

Item	Unit	CCGT (GE 9F.03 no CCS)	CCGT (GE 9F.03 with CCS, 90% capture)	CCGT (GE 9F.03 with CCS, 50% capture)
Decommissioning & demolition costs	\$/MW	52,500	60,500	57,000
Rehabilitation costs	\$/MW	58,500	67,000	64,000
Disposal costs	\$/MW	17,500	20,000	19,000
Recycling costs	\$/MW	(23,000)	(26,500)	(24,500)
Retirement cost	\$/MW	105,500	121,000	115,500

3.12 Bioenergy

3.12.1 Overview

The following is considered for power generation from bioenergy:

– Combustion of biomass in a boiler for steam generation followed by power generation
– Anaerobic digestion to produce biogas, biogas cleanup to remove H_2S and other contaminants and combustion of biogas in engines for power generation
– Generation and capture of landfill gas (LFG), cleanup and combustion of LFG in engines for power generation
– Gasification of biomass, gas cleanup to remove contaminants and combustion of the produced syngas in a gas turbine
– Biodiesel production

3.12.2 Bioenergy's contribution to Australia's energy mix

Bioenergy, including biomass, municipal and industrial waste, biogas and biofuels (bioethanol and biodiesel) production accounted for 191.3 PJ/a, or ~1% of Australian energy consumption in 2023-2024[106]. The reported split of different bioenergy types is shown in Table 3.77.

Table 3.77 Bioenergy consumption split for 2015 to 2024 (PJ/annum)

Biomass type	2023-24	2021-22	2019-20	2017-18	2015-16
Biomass	***162.9***	***171***	***169.3***	***189.6***	***196.1***
Wood and other	80	86.6	85.5	89.4	93.3
Bagasse	82.9	84.4	83.8	100.2	102.2
MSW and industrial waste	4.6	4.7	4	4.8	2.5
Biogas	***17.8***	***18.5***	***16.7***	***16.1***	***15.8***
LFG	13	13.9	12.6	12.2	14.7
Other biogas[107]	4.8	4.6	4	3.9	1.1
Biofuels	***6.0***	***6.1***	***6.6***	***7.2***	***7.2***

[106] **Renewables | energy.gov.au.** Website accessed 09/09/2025.
[107] "Other biogas" sources could refer to gas from anaerobic digestion (prevalent), biomass gasification, biomass pyrolysis gas

Biomass type	2023-24	2021-22	2019-20	2017-18	2015-16
Bio-ethanol	4.9	4.8	5.4	6	5.3
Bio-diesel	0.2	0.2	0.1	0	0.2
Other liquid biofuels	1.7	1.1	1.1	1.2	0.9

The contribution from various biomass types have remained relatively consistent over the last 10 years, with solid biomass (wood and bagasse) decreasing gradually, MSW and industrial waste almost doubling from 2015-16 to 2017-18 and then remaining consistent, biofuels consumption gradually decreasing to 83% of the value in 2015-16 by 2023-24 and biogas increasing by almost 13% from 2015-16 to 2023-24.

According to Australia's Bioenergy Roadmap[108], published November 2021 by Australian Renewable Energy Agency (ARENA), the projected bioenergy demand for grid electricity in 2050 could be approximately 17 TWh under the Targeted Deployment scenario, or 6.1% of the current power generation capacity (assuming no growth in total power generation capacity). Bioenergy demand is typically constrained by the feedstock supply.

3.12.3 Bioenergy circular economy systems

By shifting from a linear waste management model to a circular economy, Australia could provide a larger proportion of power generation from bioenergy, reduce feedstock and logistics costs and increase efficient use of natural resources such as water and energy.

Bioenergy offers another alternative feedstock for power generation. Bioenergy generated from biomass, including agricultural and forestry residues, commercial and household food and garden organics, can circulate the energy and carbon embodied in those materials.

Processes for converting organic materials to provide energy are proven. In 2019, the World Biogas Association reported that there were 132,000 small, medium and large scale anaerobic digesters and 700 biogas upgrading facilities operating globally. In Australia, the Malabar Jemena plant has been producing biogas and upgrading the biogas to biomethane for injection to the grid since 2023. The plant demonstrates circularity in resource management, with household wastes being turned into bioenergy for use by the same households/industries located near the plant.[109]

3.12.4 Emerging sustainability issues

Feedstocks selected for bioenergy use should deliver at least 60-70% greenhouse gas savings compared to fossil fuels, including land-use change (direct and indirect), cultivation, harvesting, processing, transport and combustion of the bioenergy.[110]

Any biomass generated for bioenergy should ideally avoid land use change impacts and protect biodiversity. As an example, energy crops such as millet and cereal and non-cereal straws can achieve high methane yields via anaerobic digestion, but their use must be carefully managed due to their impact of energy crops cultivation on land use change and food security.

When it comes to harnessing biomass for energy, the biomass supply within a reasonable area is important. Typically, biomass has a low bulk density and high moisture content, so that transport from the source to processing site requires a large number of trucks and results in a high transport cost (particularly expressed as "per energy unit"). The supply is also typically widely spread geographically and seasonal, so that many feedstocks are only available at harvest time and requires considerable storage, usually at the processing site.

Variation in feedstock quality is an operational issue that each facility that processes biomass must manage.

For anaerobic digestion specifically, water use is considerable, and therefore there is interest in methods to reduce the overall water use, such as water treatment and recycling as well as the increased development of dry anaerobic digestion methods.

[108] Australia's Bioenergy Roadmap. November 2021. Prepared by ENEA Australia Pty Ltd and Deloitte Financial Advisory Pty Ltd for ARENA
[109] **Malabar Biomethane Injection Plant | Jemena.** Website accessed 09/09/2025.
[110] **Carbon emissions of different fuels - Forest Research**

It is also important to consider the “business as usual” (BAU) for a particular biomass and what the associated carbon emissions are to replace the biomass if it is diverted to bioenergy production.

3.12.5 Recent trends in bioenergy production

3.12.5.1 Anaerobic Digestion

The anaerobic digestion (AD) market is projected to reach US$32 billion by 2031, growing by more than 10% from 2024 to 2031[111]. The market growth is driven by the rising demand for renewable energy sources, government initiatives supporting the development and adoption of AD systems, the growing need for safe waste disposal and increasing awareness regarding the benefits of AD. AD has relatively low LCOE compared to many other processes utilising biomass feedstocks, such as biodiesel or renewable liquid fuels production, as examples.

North America has the largest share in the global AD systems market (at almost 35%), while Asia-Pacific is the region with the highest growth rate at 11%[112]. The growth is driven by the rising demand for AD in various applications such as power generation and the increasing implementation of waste management regulations aimed at reducing the amount of waste sent to landfills.

Continuous improvements in reactor design, pretreatment methods of feedstocks and process optimisation are enhancing efficiency and biogas yield per tonne of feedstock. Using digestate for soil carbon, fertiliser or other resource recovery is viewed as key for overall sustainability.

More farms and food processing facilities are considering digesters to avoid increasing disposal costs, produce energy for their own use and manage waste sustainably. Organic waste policies (that is reducing landfilling of feed waste) are pushing local councils and waste companies to adopt AD.

The dry AD market is experiencing robust growth, driven by the need to implement sustainable waste management, need to produce renewable energy and a need to reduce water requirement for renewable energy projects, particularly in areas facing water scarcity.

Australia has a number of smaller AD facilities, but no large plants. This is mainly due to relatively low population concentration in most areas in Australia and therefore feedstock constraints. Most are wastewater and LFG facilities. Emphasis is on proving viability, managing feedstock supply and matching scale to regional demand. One of the biggest challenges for Australia and AD is federal and state policies that are highly varied on waste transport management and digestate management, and also in flux. There is however growing support for the production of biogas, such as the GreenPower Renewable Gas Certification scheme, a government-accredited voluntary renewable gas certification in Australia for biomethane and renewable hydrogen, launched in 2022. There is also stronger support to manage wastes from households better and sort these for better feedstock management for AD. This ultimately results in increased waste feedstock being accessible for AD and biogas production in Australia.

Australia possesses abundant feedstocks that are suitable for AD; in the order of 2,300 PJ pa of bioenergy[113]. This is the total bioresource potential rather than what is practically recovered, which would typically be a much lower value. One of the most important factors to consider is the concentration of biomass, that is how much biomass is available in a relatively small area to be transported to a centralised site for processing.

AD is considered one of the lower cost options to process biomass and produce bio-energy, with a typical LCOE in the order of A$10.3 – 29.5/GJ for urban and C&I waste and A$30.0 – 42.3/GJ for agricultural wastes[114].

Policy, market and technology advances, together with increased access to suitable feedstocks, are predicted to result in increased biomethane production through AD. From a report by blunomy the levelised cost of biomethane is expected to decrease over time, so that the first 50 PJ/a of supply could be delivered at a cost of A$10-27/GJ in 2030, A$10-25/GJ in 2040 or A$10-23/GJ in 2050[115].

[111] **Anaerobic Digestion Systems Market Size, Forecasts, & Trends Analysis 2024-2031: Rising Demand for Renewable Energy, Government Support Drives Expansion, Innovations Driving Opportunities - ResearchAndMarkets.com.** Website accessed 22/09/2025.
[112] **Anaerobic Digestion Systems Market Size, Forecasts, & Trends Analysis 2024-2031: Rising Demand for Renewable Energy, Government Support Drives Expansion, Innovations Driving Opportunities - ResearchAndMarkets.com.** Website accessed 22/09/2025.
[113] **biomethane-opportunities-to-decarbonise-australian-industry.pdf**
[114] AGIG & blunomy. (2024). Biomethane potential in AGIG's network catchment and associated co-benefits.
[115] **biomethane-opportunities-to-decarbonise-australian-industry.pdf**

3.12.5.2 Landfill gas

LFG is one of the cheaper sources of biogas at present. However, there are constraints associated with extracting gas from landfill gas in the foreseeable future, with organics that are currently sent to landfill expected to be phased out in the near future, which will severely impact the opportunity to produce LFG. It is anticipated that landfill gas in closed landfills will deplete over time to nearly zero over the next 20 years. The lifetime of landfills are typically only around 15 years or so.

Although landfills are relatively cheap production sources of biogas, they tend to have relatively small gas production capacity.

3.12.5.3 Biodiesel and renewable diesel production

There are three biodiesel plants on Australia's east coast with combined capacity ~110 million litres/year; currently operating at ~10-20% utilisation due to cost competitiveness issues. Feedstocks are limited and expensive. Australia currently exports approximately 2-3 million tonnes per annum of Canola seed to the EU for biodiesel or renewable diesel production. In addition, large volumes of tallow (450,000 tonnes per annum in 2022-2023) are also exported to Singapore and the USA. Some Used Cooking Oil (UCO) is also exported.

Australia has established a fuel standard for renewable diesel (paraffinic diesel), so that the development of renewable diesel is easier than in the past. There are various projects in development:

– **Project Ulysses (Townsville)**: biofuel hub planned that will produce ~113 million litres/year of SAF + renewable diesel from agricultural by-products via the Alcohol-To-Jet (ATJ) process. Commissioning is planned by ~2028[116]. The feedstock will be bio-ethanol sourced from bio-ethanol production facilities.

– **Rio Tinto Pongamia farm trial**: seed farms being developed in north Queensland (~3,000 ha) to test seed oil yields for possible use in renewable diesel feedstock[117] via the HEFA process.

– **Rio Tinto / Viva Energy trial in the Pilbara**: used cooking oil-based renewable diesel (~10 million litres) produced elsewhere via the HEFA process has been blended (~20%) and used in mining / port operations[118].

– **Ampol, GrainCorp, IFM pre-FEED** to explore the potential to produce SAF + renewable diesel from local feedstocks[119]. Currently, oil feedstocks are being targeted for the HEFA process.

Due to the high cost associated with biodiesel and renewable diesel production and relative uncertainty with regards to regulatory support by the Australian government, major facilities of these types have not been developed in Australia. However there is increased support by the federal government, support by airlines to drive in particular SAF production and with recently announced funding by the federal government, it is expected that there will be an increase in particularly renewable diesel production in the near future in Australia.

The Australian Federal Government announced the investment of A$1.1 B to help unlock economic opportunities from low carbon liquid fuels in 2025[120]. The aim of the funding is to help ensure strong supply chains for more sustainable fuels and to stimulate private investment in Australian onshore production of low carbon liquid fuels such as renewable diesel and sustainable aviation fuel over the next ten years.

3.12.5.4 Biomass

The Australian biomass market is expected to grow at a rate of 7.8% during 2025-2033[121]. Drivers include government incentives for clean energy, sustainability goals and the agricultural sector's tapping into biomass wastes. Technological advances in biomass conversion are also contributing to market growth.

The focus is shifting towards utilising residues and wastes for energy generation, such as forestry residues, sawmill by-products, crop residues (such as straws) and municipal solid waste (MSW).

[116] **Courier Mail: https://www.couriermail.com.au/news/jet-zero-welcomes-federal-support-for-project-ulysses-at-industrial-park/news-story/424238622fe7d54183267c8cada36d62**
[117] **Rio Tinto: https://www.riotinto.com/en/news/releases/2024/rio-tinto-launches-biofuel-crop-farming-trial-for-renewable-diesel-production-in-australia**
[118] **Biofuels Central: https://biofuelscentral.com/rio-tinto-conducts-first-renewable-diesel-trial-across-pilbara-iron-ore-operations/**
[119] **Ampol: https://www.ampol.com.au/about-ampol/powering-next/future-energy/brisbane-renewable-fuels**
[120] **Joint media release: Fuelling the future: $1.1 billion to power cleaner Aussie fuel production | Ministers**
[121] **Australia Biomass Market Size & Share 2025-33**

Australia's agricultural sector produces a large volume of biomass residues, which offer a significant opportunity for sustainable energy generation. It is claimed that every tonne of crop residue could generate between 2-3 MWh of electricity[122]. More than 80 million tonnes per annum of agricultural and forestry waste is estimated to be produced in Australia[123].

Traditionally, agricultural and forestry wastes are not collected but left on the ground, buried or burned. However, these sectors are moving towards more sustainable development, including the collection and valorisation of residues[124]. It should be noted that leaving some wastes on the ground, for example some cereal straws, is beneficial to the soil as it serves to reduce moisture evaporation and supresses weed growth, and therefore only a portion of these materials would be available for bioenergy generation.

Australia currently exports approximately A$ 4B of bioenergy feedstocks[125]. These include feedstocks such as canola, tallow and woodchip, with the canola and tallow targeted for HEFA plants in Europe and Singapore.

3.12.5.5 Summary of changes

Relating to bioenergy, the following changes are observed between the 2024 report and this Report:

– Biogas production via anaerobic digestion and energy production from biogas CAPEX is approximately 11% higher compared to the 2024 report. CAPEX is based on benchmark values gathered over a range of projects by GHD for anaerobic digestion and CHP.
– OPEX for biogas production via anaerobic digestion and energy production from biogas is approximately 14% lower compared to the 2024 report. Total OPEX (variable and fixed) is based on 5% CAPEX per annum in this report, and excludes feedstock cost.
– A hypothetical project has been included for biogas production from landfill gas, as one of the main sources of biogas and electricity generation in Australia at present.
– There is a significant change in cost of land and development from the 2024 report, since actual plant footprints and estimated land cost for industrial land near urban centres (so that the AD and LFG facilities are close to significant feedstock sources) are included in this report, rather than a percentage of CAPEX.
– Biomass gasification has been included in this report as a hypothetical project. The complexity and costs are higher than for biomass combustion.
– For biodiesel production, the development time for a hypothetical project has been extended, mainly based on GHD's experience with procurement of feedstocks for the project. In addition, the CAPEX estimate is 25% higher than for the 2024 report, based on CAPEX for an Australian project of similar capacity and refreshed with CEPCI to a 2024 basis. Total OPEX is also approximately ~13% higher than for the 2024 report, mainly due to the inclusion of expected feedstock costs, based on GHD experience.

3.12.6 Biogas systems descriptions

3.12.6.1 Anaerobic digestion

Anaerobic digestion is a process where organic matter degrades in an oxygen-depleted environment to produce two products:

– Biogas, which can be processed to generate renewable energy (e.g. power and/or heat)
– Digestate, which is the residual material from anaerobic digestion and may potentially be further treated to allow for land application (i.e., as soil-enhancer)

Depending on the type and composition of the feedstock, sludge may undergo pretreatment processes such as mechanical, thermal, chemical or biological methods to significantly enhance the methane yield, improve digestate rheology (to enhance mixing/heating) and reduce the retention time in the anaerobic digesters.

To maintain a constant temperature in the digesters, heat exchange systems are often installed to transfer heat from the biogas or the digestate to the incoming sludge. Alternatively, external heating sources such as steam or

[122] **How Australia's Abundant Biomass Can Power Our Sustainable Future - Sustainable Future Australia**
[123] **How Smart Technology Is Transforming Farm Waste Into Australia's Next Energy Goldmine - Sustainable Future Australia**
[124] Lackner, M. and Besharati, M. (2025). Agricultural waste: Challenges and Solutions, A review. Waste 3 (2), 18.
[125] **Joint media release: Fuelling the future: $1.1 billion to power cleaner Aussie fuel production | Ministers**

hot water can be used to heat the digesters. The heating system should be designed to avoid temperature fluctuations and ensure uniform distribution of heat throughout the digester volume.

The biogas that is produced typically contains 50-60 vol% methane, 20-40 vol% CO_2, 0-5 vol% N_2 and 0-1 vol% O_2. The gas is saturated at the production conditions and also contains contaminant species such as H_2S (10 – 10,000 ppmv depending on the feedstock), organic sulphur compounds (trace to 50 ppmv), NH_3 (10-100 ppmv) and siloxanes (0-50 mg/m^3).

Biogas treatment is the process of removing contaminants such as hydrogen sulphide, water vapor, siloxanes, and ammonia from the biogas produced by anaerobic digestion. The level and method of treatment depends on the quality of the biogas and its intended use. Biogas can be partially treated using gas scrubbing, membrane separation, or chemical absorption. This is sufficient treatment for power generation.

For ***biomethane production and injection into the natural gas grid***, carbon dioxide (and potentially nitrogen) should also be removed, and the biomethane compressed to be injected to the natural gas network. Typically, the biomethane/biogas is compressed prior to gas treatment to reduce the volume of the gas treatment units.

Digestate is a wet mixture with a moisture content of about 90-95%. Dewatering is a process for separating the liquid and solid components, enabling additional treatment of each fraction. The liquid fraction can be treated to either recover the nutrients such as nitrogen and phosphorus with the intent to be used as fertiliser or remove the nutrients to recover or discharge the water. The solid fraction can be treated to produce a stable product enriched with nutrients to be used as a soil enhancer.

3.12.6.2 Landfill Gas

Landfill gas (LFG) is produced from the decomposition of organics within landfill waste over a long duration. LFG typically consists of 50-60vol% methane with the bulk of the remainder carbon dioxide. Landfills are capped and the gas captured via a “well” network from the decomposing wastes. The concentration of landfills close to urban areas presents an opportunity for landfill gas to be recovered, treated and injected into the existing distribution network.

The properties of landfill gas are determined by a number of factors, including, the size of the landfill, the amount of liquid present in the cells, temperature, the age of the landfill, the types of waste discarded and its constituent mass. Over the lifespan of a landfill, the materials stored will undergo four phases of decomposition, one of them aerobic and three of them anaerobic. Methane production does not begin until phase three and increases until a stabilisation point at around 45-60% of the gas content. Carbon dioxide makes up another 40-60% of the gas with the remaining 2-9% being nitrogen, sulphide or other chemicals[126]. A higher organic content present within the landfill can increase the methane content present in the gas, but after it reaches phase four, biogas is produced at a relatively stable rate for around 20 years[127]. The landfill is likely to continue producing gas for more than 50 years after the initial waste is deposited, but the methane content and gas flow gradually decreases over time.

[126] **https://www.mass.gov/doc/odorous-gas-policy-appendices-a-through-h/download**
[127] **https://www.mass.gov/doc/odorous-gas-policy-appendices-a-through-h/download**

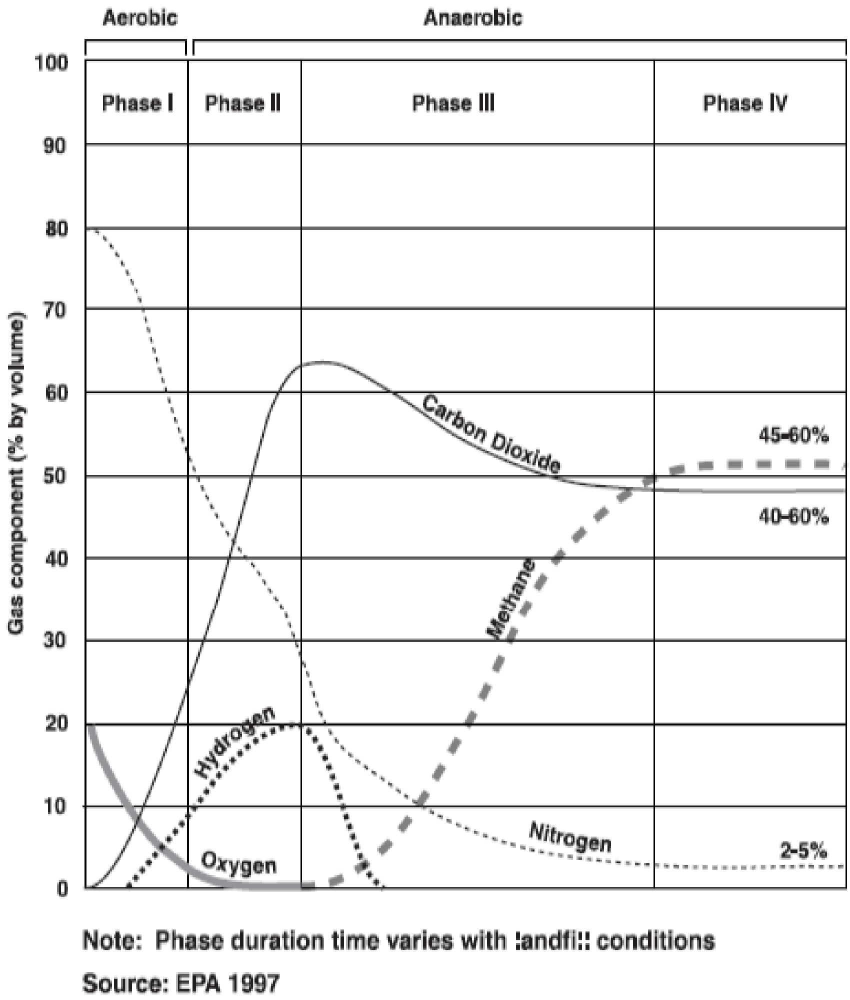

Figure 3-1 Landfill gas production phases[128]

There are many landfills in Australia; most of these are relatively small. The larger facilities tend to have power generation associated with them, where the LFG is captured, treated to remove contaminants and then combusted in gas engines.

The LFG is collected via a system of vertical and horizontal wells drilled into the landfill. The collection system is maintained under slight vacuum by a blower to ensure continuous extraction of LFG. The gas is treated to remove moisture (knockout drum or condensate trap), entrained solids and passed through an activated carbon bed to remove H_2S and siloxanes. This is typically followed by a gas engine for power generation.

3.12.6.3 Hypothetical biogas project

There are a number of projects in Australia where biogas is generated and utilised for power generation; these include:

- The Eastern Treatment Plant and Western Treatment Plant in Melbourne, Victoria. The biogas is collected and combusted at on-site power stations to convert into power which is provided back to the treatment plants. The Western Treatment Plant generates 86,000 MWh[129] of power per annum or approximately 10MW capacity.
- A number of landfills collect their biogas (LFG) and utilise it to generate power, including Lucas Heights[130], NSW (135,000 MWh/a, or 21 MW capacity), the Clayton LFG facility in Victoria generating 12 MW capacity, and a number of smaller facilities around the country (2 MW or smaller capacity).

[128] **https://www.mass.gov/doc/odorous-gas-policy-appendices-a-through-h/download**
[129] Biogas | Melbourne Water. Website accessed 10/09/2025.
[130] Lucas Heights I and II Power Station: Landfill Gas to Electricity in New South Wales, Australia | EDL. Website accessed 10/09/2025.

If a facility has a nameplate rating of less than 5MW, it is generally exempt from registering with AEMO and does not have to meet technical standards such as grid connection standards, performance standards and SCADA visibility. As a result, two facilities each with a power generation capacity below 5 MW was selected for power generation from biogas:

– A facility with anaerobic digestion for biogas production, minimal biogas treatment and CHP for power generation. The heat generated is supplied to the digesters.
– LFG facility collecting biogas production, minimal biogas treatment and gas engines for power generation.

Each of these facilities are assumed to be able to generate 2.4 MW.

Table 3.78 Configuration and performance – Biogas from AD

Item	Unit	Value	Comment
Configuration			
Technology		Anaerobic digestion with CHP generation	System includes feedstock receival, storage and pre-treatment, AD, gas treatment and CHP
Fuel source		Organic feedstocks	Examples include food wastes, manures, sewage and agricultural residues
Make model		Australian and global biogas consultants	Vendors include Hydroflux Epco and Aquatec Maxcon for AD and Jenbacher for CHPs
Unit size (Nominal)	MW	2.4 MW electrical, 2.4 MW thermal	
Number of units		2 CHP units	Assume 2 x generators for reliability
Gas fuel LHV	kWh/Nm^3	5.47	Starting from CH_4 LHV of 35.8 MJ/Nm^3 and assuming 55 vol% CH_4 in biogas
Performance			
Total plant size (Gross)	MW	2.4 MW electrical, 2.4 MW thermal	Heat generated is utilised by digester
Total plant size (Net)	MW	2.0 electrical	
Biogas production	Nm^3/annum	7,313,360	
Methane production	Nm^3/annum	4,022,350	Assuming 55 vol% CH_4 in biogas and 8,400 operating hours per annum
Electricity generation	kWh/annum	16,800,000	Assuming 8,400 operating hours per annum
Digestate	m^3/annum	92,500	
CHP electrical efficiency	%	42	37-38% electrical efficiency only
Site Parasitic Electrical Load	%	8	
Site Parasitic Heat (Water) Load	%	25	
Average Planned Maintenance	Days / year	15	

Table 3.79 Configuration and performance – Biogas from LFG

Item	Unit	Value	Comment
Configuration			
Technology		LFG capture with gas engines	System of collection wells, blower to maintain slight vacuum, basic gas treatment and gas engines
Fuel source		Organic feedstocks in landfill	Organics in general household wastes
Make model		Australian LFG collection specialists, gas engine OEM	Vendors include Jenbacher and MWM for gas engines
Unit size (Nominal)	MW	2.5 MW electrical	Heat could also be generated but there is typically no use for it
Number of units		2 gas engines	
Gas fuel LHV	kWh/Nm^3	5.47	Assuming 55 vol% CH_4 in LFG
Performance			
Total plant size (Gross)	MW	2.5 MW	
Total plant size (Net)	MW	2.0 MW	
LFG production	Nm^3/annum	7,313,360	
Methane production	Nm^3/annum	4,022,360	
Electricity generation	kWh/annum	16,800,000	
Gas engine electrical efficiency	%	42	
Site Parasitic Electrical Load	%	8	Similar assumed to digester site, typically 5-8% of gross generation
Average Planned Maintenance	Days / year	15	

Table 3.80 Project timeline – Biogas from AD

Item	Unit	Value	Comment
Project timeline			
Time for development	Years	2	Includes pre-feasibility, feasibility, design, approvals, procurement etc.
First year assumed commercially viable for construction	Year	2025	
EPC programme	Years	2	
– Total lead time	Years	1	
– Construction time	Weeks	52	
Economic life (Design life)	Years	20	
Technical life (Operational life)	Years	30	Includes the assumption that CHP units undergo major overhaul at OEM prescribed intervals

Table 3.81 Project timeline – Biogas from LFG

Item	Unit	Value	Comment
Project timeline			
Time for development	Years	2 + 1-2 years to reach steady gas production	Includes pre-feasibility, feasibility, design, approvals, procurement etc.
First year assumed commercially viable for construction	Year	2025	
EPC programme	Years	1	
– Total lead time	Years	0.5	
– Construction time	Weeks	26	
Economic life (Design life)	Years	15	
Technical life (Operational life)	Years	Up to 50 years	Includes the assumption that gas engines undergo major overhaul at OEM prescribed intervals. Landfill gas infrastructure can produce gas for up to 50 years but will decline over time.

3.12.6.4 Development cost estimates (Hypothetical biogas project)

The following table provides CAPEX cost estimates for the defined biogas project.

Table 3.82 Development cost estimates – Biogas from AD

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW (Net)	17,720	Based on GHD benchmarking for AD and CHP
Total EPC cost	$	35,443,000	
– Equipment cost	$	14,177,200	40% of EPC cost is typical
– Construction cost	$	21,265,800	60% of EPC cost is typical
Other costs			
Cost of land and development	$	10,750,000-15,050,000 on the low end 30,750,000-43,050,000 on the high end	Assuming 5-7 ha required for a 2 MW AD facility, A$2.0 – 6.0/ha for industrial land[131] and A$150,000/ha for land preparation cost
Feedstock supply costs	$	0-100/t	Highly dependent on the type of feedstock utilised. For wastes, the cost could be negative as the project could take advantage of gate fees for diverted wastes. Agricultural wastes such as straws are likely to incur a feedstock cost.

[131] Typically, developments are done close to large urban areas to make use of nearby waste sources, but on the outskirts to also take advantage of lower land costs away from city centers.

Table 3.83 Development cost estimates – Biogas from LFG

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW (Net)	5,100	Based on GHD benchmarking for LFG collection and gas engines
Total EPC cost	$	10,200,000	
– Equipment cost	$	4,080,000	40% of EPC cost assumed
– Construction cost	$	6,120,000	60% of EPC cost assumed
Other costs			
Cost of land and development	$	$5,000,000-10,000,000 on the low end and $10,000,000-20,000,000 on the high end.	Assuming 10-20 ha required, and low land cost of $500,000-$1,000,000/ha. This includes the landfill site.
Feedstock supply costs	$	$0	Feedstock cost could be negative due to gate fee charged.

3.12.6.5 O&M cost estimates (Hypothetical biogas project)

The following tables provides fixed, variable and total annual O&M cost estimates for the defined biogas and biogas from LFG projects.

Table 3.84 O&M cost estimates – Biogas from AD

Item	Unit	Value	Comment
Fixed O&M cost	$/MW/year (Net)	$354,430	2% of CAPEX assumed per annum
Variable O&M cost	$/MWh (Net)	$63.29	3% of CAPEX assumed per annum
Total annual O&M cost	$	$1,772,150	

Table 3.85 O&M cost estimates – Biogas from LFG

Item	Unit	Value	Comment
Fixed O&M cost	$/MW/year (Net)	$102,000	2% of CAPEX assumed per annum
Variable O&M cost	$/MWh (Net)	$30.36	5% of CAPEX assumed per annum
Total annual O&M cost	$	$714,000	

3.12.6.6 Retirement cost estimates (Hypothetical biogas project)

Retirement costs for the defined biogas project are outlined in the table below.

For retirement of a biogas facility, the following must be completed:

- Dewater and remove sludge from the digester
- Equipment removal, including feedstock receival and storage, digesters (tanks), CHP units and flare
- Digestate and other solids on site should be disposed
- Site should be remediated and the site restored to a state suitable for future use

For retirement of a facility with LFG and power generation, the following must be completed:

- Power generation equipment and flare should be removed
- Depleted wells should be capped. Typically, gas and water monitoring would continue for considerable time for the landfill itself.

Table 3.86 Retirement cost estimates – Biogas

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$ / MW (Net)	500,000	
Disposal costs	$ / MW (Net)	100,000	Based on an assumed $25,000/MW for concrete disposal, $40,000/MW for hazardous materials (digestate, chemicals), and $22,000/MW for CHP disposal, plus 15% contingency for unknowns
Recycling costs	$ / MW (Net)	(38,500)	$10,000/MW for steel recycling and $28,500 for CHP materials recycling
Total retirement costs	$ / MW (Net)	561,500	

Table 3.87 Retirement cost estimates – LFG

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$ / MW (Net)	372,000	$5,000/well, assume 100 wells, piping and flare removal $100,000/MW, $22,000/MW for gas engine removal.
Disposal costs	$ / MW (Net)	32,000	$22,000/MW for gas engine disposal and $10,000/MW for concrete and other materials
Recycling costs	$ / MW (Net)	(43,500)	$15,000/MW for steel and $28,500/MW for gas engine materials
Total retirement costs	$ / MW (Net)	360,500	

The retirement cost estimates for LFG does not consider costs associated with continuous monitoring of the site. This could amount to A$1.5 to A$ 4.0 million dollars or more over a 15-to-30-year monitoring period.

3.12.7 Biomass generators using wood waste

3.12.7.1 Biomass combustion

Solid biomass such as wood chips, bagasse or straw is combusted in a fixed or moving grate furnace, fluidised bed combustor or pulverised fuel combustor system. Each of these requires a different level of feedstock preparation such as milling, pelleting and/or drying.

The heat from biomass combustion generates steam which in turn drives a steam turbine for power generation. The flue gas is treated to remove entrained ash particulates (through for example bag houses), and NOx control is typically required.

Ash is removed from the combustor and disposed or used as soil enhancer if acceptable.

3.12.7.1.1 Hypothetical biomass project

Table 3.88 Configuration and performance – Biomass Combustion Unit

Item	Unit	Value	Comment
Configuration			
Technology	-	Sub-critical boiler	Combustion unit, includes mechanical draft cooling tower
Fuel source	-	Woodchips	-
Make model	-	European OEM	Examples include Andritz and Valmet
Unit size (Nominal)	MW (AC)	30	-
Number of units	-	1	-
Main steam pressure	MPag	7.0	-

Item	Unit	Value	Comment
Main steam temperature	°C	470.0	Super-heated by 185°C
Process steam pressure	MPag	5.7	-
Process steam temperature	°C	162.0	-
Process steam mass flow rate	kg/s	16.0	-
Condenser pressure	kPaa	7.5	-
Performance			
Electrical plant size (Gross)	MW	30	Climatic conditions assumed are 25°C, 110 m above sea level, 60% RH
Process heat capacity	MW_{th}	44.3	-
Auxiliary power consumption	%	7.3	-
Electrical plant size (Net)	MW	27.8	25°C, 110 meters above sea level, 60% RH
Seasonal Rating – Summer (Net)	MW	27.4	35°C, 110 meters above sea level, 60% RH
Seasonal Rating – Not Summer (Net)	MW	28.0	15°C, 110 meters above sea level, 60% RH
Heat rate at minimum operation (Electric)	(GJ/MWh) HHV Net	18.1	-
Heat rate at maximum operation (Electric)	(GJ/MWh) HHV Net	16.3	-
Thermal Efficiency (Electric) at MCR	%, HHV Net	22.2	-
CHP Efficiency	%, HHV Net	57.4	-
Annual performance			
Average planned maintenance	Days / year	22.8	-
Equivalent forced outage rate	%	4.0	-
Annual capacity factor	%	89.8	-
Annual electricity generation	MWh / year	218,688	-
Annual degradation over design life – Output	%	1-2% for the first 18 months of operation, then low level degradation	-
Annual degradation over design life – Heat rate	%	0.2	-

Table 3.89 Technical parameters and project timeline – Biomass Combustion Unit

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	1.2	Based on 3%/min standard operation
Ramp down rate	MW / min	1.2	Based on 3%/min standard operation
Start-up time	Min	Cold – 420 Hot – 60	-
Min stable generation	% of installed capacity	40	-
Project timeline			

Item	Unit	Value	Comment
Time for development	Years	3	Includes pre-feasibility, feasibility, design, approvals, procurement, etc.
First year assumed commercially viable for construction	Year	2025	-
EPC programme	Years	3	-
– Total lead time	Years	1.75	-
– Construction time	Weeks	65	-
Economic life (Design life)	Years	25	-
Technical life (Operational life)	Years	30	Could be further extended with major overhauls during the lifetime of the project

3.12.7.1.2 Development cost estimates (Hypothetical biomass project)

The following table provides CAPEX cost estimates for the defined biomass project.

Table 3.90 Development cost estimates – Biomass Combustion Unit

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW	8,300 3,000	Electrical energy basis Electrical and thermal energy basis Escalated from 2024 report[132]
Total EPC cost	$	230,740,000	-
– Equipment cost	$	138,444,000	40% of EPC cost assumed
– Construction cost	$	92,296,000	60% of EPC cost assumed
Other costs			
Cost of land and development	$	20,767,000	Assuming 9% of CAPEX
Feedstock connection costs	$	0	Feedstock at this scale would be delivered by road (truck).

3.12.7.1.3 O&M cost estimates (Hypothetical biomass project)

The following table provides fixed, variable and total annual O&M cost estimates for the defined biomass project.

Table 3.91 O&M cost estimates – Biomass Combustion Unit

Item	Unit	Value	Comment
Fixed O&M cost	$/MW (Net)	186,130	Escalated from 2024 figure[133]
Variable O&M cost	$/MWh (Net)	10.9	Escalated from 2024 figure[134]
Total annual O&M cost	$	7,550,000	-

3.12.7.1.4 Retirement cost estimates (Hypothetical biomass project)

Retirement costs for the defined biomass project are outlined in the table below.

[132] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024
[133] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024
[134] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024

Table 3.92 Retirement cost estimates – Biomass Combustion Unit

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$ / MW (Net)	150,000	Costs are assumed in the range of $125,000–$150,000/MW, upper end selected
Disposal costs	$ / MW (Net)	2,000	Very little ash produced from biomass, thus no major ash disposal cost included
Recycling costs	$ / MW (Net)	(18,500)	Steel recycling
Total retirement costs	$ / MW (Net)	133,500	-

3.12.7.2 Biomass gasification and power generation

Biomass can be gasified following pre-treatment (such as milling, sizing and drying) to produce a combustible gas mixture, typically referred to as “synthesis gas”. The biomass is reacted with a sub-stoichiometric amount of oxygen and steam may be used as temperature moderator in the gasifier. Typically, temperatures of 700+°C are maintained in the gasifier and operating pressure is typically maintained between 20-40 barg. The produced gas is a mixture of CO, H_2, CH_4, CO_2, N_2, H_2O and various contaminant species such as tars, reduced sulphur and nitrogen species. If the gasifier is air-blown rather than oxygen blown, a large volume of nitrogen will be present in the synthesis gas, reducing the calorific value of the gas.

The gas is treated following gasification to remove contaminant species and then combusted in a gas turbine, simple cycle gas turbine or integrated gasification combined cycle (IGCC) configuration. These systems are typically more efficient than biomass combustion systems, but the gas treatment is challenging, and costs can make small scale plants uneconomic.

3.12.7.2.1 Hypothetical biomass project

Table 3.93 Configuration and performance – Biomass Gasification Unit

Item	Unit	Value	Comment
Configuration			
Technology	-	Fluidised bed gasifier and gas turbine	Includes feed system, gasifier, ash system, primary gas treatment and gas turbine
Fuel source	-	Woodchips	
Make model	-	European OEM	Examples include Royal Dutch Shell, General Electric and ThyssenKrupp
Unit size (Nominal)	MW (AC)	22.1	400 t/day wet biomass feed
Number of units	-	1	-
Gasifier temperature	°C	850-900	-
Gasifier pressure	Barg	20-30	-
Syngas production	kg/h	26,500	Wet syngas
Lower heating value for syngas	MJ/kg	7.5	-
Performance			
Electrical plant size (Gross)	MW	22.1	Climatic conditions assumed 25°C, 110 meters above sea level, 60% RH
Auxiliary power consumption	%	6.0	
Electrical plant size (Net)	MW	20.8	
Thermal Efficiency (Electric)	%, LHV Net	40.0	
Annual performance			
Average planned maintenance	Days / year	22.8	

Item	Unit	Value	Comment
Equivalent forced outage rate	%	4.0	
Annual capacity factor	%	89.8	
Annual electricity generation	MWh / year	179,356	
Annual degradation over design life – Output	%	1-2% for the first 18 months of operation, then low level degradation	
Annual degradation over design life – Heat rate	%	0.2	

Table 3.94 Technical parameters and project timeline – Biomass Gasification Unit

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	1.2	Based on 3%/min standard operation
Ramp down rate	MW / min	1.2	Based on 3%/min standard operation
Start-up time	Min	Cold – 420 Hot – 60	
Min stable generation	% of installed capacity	50	Of design solid feed rate to gasifier
Project timeline			
Time for development	Years	3	Includes pre-feasibility, feasibility, design, approvals, procurement, etc.
First year assumed commercially viable for construction	Year	2025	
EPC programme	Years	3	
– Total lead time	Years	1.75	
– Construction time	Weeks	65	
Economic life (Design life)	Years	25	
Technical life (Operational life)	Years	30	Could be further extended with major overhauls during the lifetime of the project

3.12.7.2.2 Development cost estimates (Hypothetical biomass project)

The following table provides CAPEX cost estimates for the defined biomass project.

Table 3.95 Development cost estimates – Biomass Gasification Unit

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW (Net)	11,110	Electrical energy basis, based on GHD project information
Total EPC cost	$	231,080,000	
– Equipment cost	$	92,432,000	40% of EPC cost assumed
– Construction cost	$	138,648,000	60% of EPC cost assumed
Other costs			
Cost of land and development	$	23,108,000	Assuming 10% of CAPEX
Feedstock connection costs	$	0	Feedstock at this scale would be delivered by road (truck).

3.12.7.2.3 O&M cost estimates (Hypothetical biomass project)

The following table provides fixed, variable and total annual O&M cost estimates for the defined biomass project.

Table 3.96 O&M cost estimates – Biomass Gasification Unit

Item	Unit	Value	Comment
Fixed O&M cost	$/MW (Net)	281,805	2.5% of CAPEX per annum
Variable O&M cost	$/MWh (Net)	14.12	1% of CAPEX per annum
Total annual O&M cost	$	8,087,800	

3.12.7.2.4 Retirement cost estimates (Hypothetical biomass project)

Retirement costs for the defined biomass project are outlined in the table below. Assumed to be very similar to biomass combustion unit.

Table 3.97 Retirement cost estimates – Biomass Gasification Unit

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$ / MW (Net)	180,000	Costs are assumed in the range of $150,000–$180,000/MW, upper end selected (120% of biomass combustion system assumed)
Disposal costs	$ / MW (Net)	2,400	Very little ash produced from biomass, thus no major ash disposal cost included
Recycling costs	$ / MW (Net)	(22,200)	Steel recycling
Total retirement costs	$ / MW (Net)	$160,200	

3.12.8 Biodiesel production

Biodiesel can be produced from vegetable oils, used cooking oils and grease and animal fats. Biodiesel production follows these general steps:

– Filtration to remove impurities from oil feedstock
– Acid esterification to remove free fatty acids from feedstock
– Transesterification to produce biodiesel
– Purification to remove glycerol by-product and catalyst.

Acid esterification requires process heating as it occurs at 125ºC and 9-10 bar. The purified triglyceride undergoes transesterification for several hours at 60ºC and atmospheric pressure with excess dry methanol and a base catalyst. Other alcohols (such as ethanol) could also be utilised. Fatty acids methyl esters (FAME) are separated from the glycerol by-product via gravity or centrifuge. The crude FAME then undergo vacuum flashing or distillation to remove unreacted alcohol to be recycled. Next the FAME is water-washed, and vacuum stripped or distilled to remove residual methanol and moisture, before the final biodiesel product is filtered.

Feedstocks such as oilseed crops can be specifically grown for biodiesel production; the oil then must be extracted from the oilseed as a first step in the biodiesel production process.

Biodiesel can be utilised for the following in power generation:

– Feedstock for gensets for backup power, as direct substitution for diesel with minimal engine modifications
– Grid-connected peaking plants, with biodiesel as feedstock
– Off-grid/island power stations feedstock
– Co-firing with crude derived diesel in combined heat and power (CHP) units
– Modified small gas turbines with preheating required to reduce viscosity

Biodiesel has a heating value that is slightly lower than that of crude derived diesel and therefore a slightly higher fuel consumption is expected for the same power output. Some engines struggle with 100% biodiesel feed, with filter clogging, higher NOx emissions and/or deposit formation if not managed well. Therefore, blends are more typically used (e.g. B5 or B20). Biodiesel substitution does not significantly reduce efficiency of power generation equipment (which is typically at 35-45% electrical efficiency) but higher maintenance frequency may be required.

3.12.9 Recent trends on biodiesel cost of production

Biodiesel has a relatively large market share. In 2023, global Fatty Acid Methyl Ester (FAME) production was almost 50 billion litres; Indonesia produced the largest volume with 14 billion litres from palm oil, followed by the EU with 13 billion litres from rapeseed and Used Cooking Oil (UCO) and Brazil with 8 billion litres, mainly from soybean[135]. Many countries have or are increasing biodiesel blending mandates, for example, B5 or B10, which is driving biodiesel demand. Typically, biodiesel is used in a blend with crude oil-derived diesel, but it can also be utilised on its own (depending on the engine specifics). The vehicular fuel industry is the leading consumer of biodiesel and accounts for almost 80% of the market share. Other uses include power generation and heating.

The biodiesel market is estimated to grow at a pace of 6.1% between 2025 and 2034 to a total volume of 108.5 billion litres by 2034[136]. Besides the high demand for biodiesel in the fuel industry, its application in power generation is also witnessing a significant growth. In Australia however, biodiesel production is modest, with approximately 15 million litres produced in 2022[137], which is a decline from the 25 million litres produced in 2021. Australia has a biodiesel capacity of 110 million litres, but current utilisation is low due to production cost in Australia and no enforced biodiesel mandates, which in turn has resulted in limited demand. Production is further constrained by limited feedstocks supply and cost.

From a position statement by Australian biodiesel producers in June 2024, the levelised cost of biodiesel was calculated to be between $1.80 and $2.00 per litre, excluding GST but including a $0.13 per litre excise[138]. The contribution from capital for the production facility is approximately 35 to 40%, implying that the major driver is the feedstock cost. As the demand for renewable fuels increase, the pressure on limited feedstocks such as UCO and tallow is likely to increase, and therefore prices are expected to increase as well. Currently, UCO has a market price of around US$900/ton (A$1,286/ton), and tallow A$2,000/ton.

3.12.10 Comparison of Hydrotreated Vegetable Oil (HVO) and renewable diesel production process

The process to produce biodiesel has relatively low capital expenditure (CAPEX) and can be done on small scale. A large proportion of the cost of production is associated with the feedstocks.

Biodiesel is chemically different to mineral diesel; biodiesel has a general formula of $C_{17}H_{34}O_2$ and contains carbon-to-carbon double bonds, whereas diesel (including renewable diesel) is typically represented as $C_{12}H_{23}$ and contains mainly paraffins with some aromatics (up to 25%). Biodiesel has a high viscosity and due to its high oxygen content has poor long-term stability, and therefore a relatively short shelf life. During oxidation, biodiesel is decomposed into smaller chain compounds such as aldehydes, shorter chain esters and similar compounds. This could lead to formation of deposits in the fuel system and formation of insoluble gums through polymerisation, leading to increased acid numbers and viscosity of the biodiesel.

Due to these inherent properties, biodiesel is usually only blended with crude derived diesel in small amounts so that it does not impact engine operability. Renewable diesel however, can typically be used interchangeably with crude derived diesel. In February 2025, the renewable diesel mandate was released in Australia, introducing a new national fuel quality standard for paraffinic diesel including renewable diesel. As a result, renewable diesel does not require any blending to be sold in the market. Previously blending was required as renewable diesel typically has a lower density than crude derived diesel.

Renewable diesel is produced from a number of processes, each with specific feedstock requirements. Most of these processes have solids processing included (due to the feedstocks that are used) and have high associated complexity and capital cost investment:

– Vegetable oils and animal fats (also used for biodiesel production) could be upgraded to renewable diesel via the Hydroprocessed Esters and Fatty Acids (HEFA) process. Vegetable oil and animal fats are catalytically

[135] **241023 GBS Report Short Version.pdf**. Website accessed 16/09/2025.
[136] **Biodiesel Market Outlook, Supply, Demand Analysis | 2032**. Website accessed 16/09/2025.
[137] **Australia Biodiesel production - data, chart | TheGlobalEconomy.com**. Website accessed 17/09/2025.
[138] **lclf2024-just-biodiesel-pty-ltd.pdf**. Website accessed 17/09/2025.

hydrotreated and separated into drop-in fuels according to their boiling points. The processing steps typically include hydrodeoxygenation, hydrocracking and isomerisation and separation through fractionation. An external hydrogen source is required for hydrotreating and hydrocracking. Currently, only the HEFA process is commercially available for renewable diesel and sustainable aviation fuel (SAF) production. The main driver for this is that the capital expenditure (CAPEX) for this type of facility is considerably lower than for other technologies producing drop-in fuels, as the feedstock is already an oil. However, feedstocks are available in limited quantities to the domestic market due to high export demand, resulting in the price of feedstocks increasing. These are the main reasons many proponents are exploring other technologies and feedstocks at present.

– Gasification of biomass and Fischer-Tropsch synthesis followed by hydrotreating and hydrocracking of the interim product is a pathway to produce renewable diesel from lignocellulosic biomass and wastes (such as agricultural wastes, domestic and industrial wastes). Solid biomass produces a synthesis gas (hydrogen and CO) through gasification and purification of the synthesis gas, followed by catalytic synthesis (Fischer-Tropsch synthesis) to a range of hydrocarbon chains. The process always produce a spread of hydrocarbons from C1 through C90+. Liquid hydrocarbons and waxes (C5-C90) are hydrocracked and hydrotreated through upgrading units to produce drop in renewable diesel (as well as other products such as SAF).
– Hydrothermal liquefaction is a process where biomass (the same feedstocks as for gasification, as well as manures and vegetable oils and animal fats) is converted to liquids through breaking the feedstock down in a super-critical water environment with or without a catalyst. The organics in the biomass is converted to a biocrude, water soluble organics and non-condensable product gases. The biocrude is similar to pyrolysis oil, but less challenging to upgrade with lower oxygen content than pyrolysis oil. The biocrude is upgraded through hydrocracking and treatment and fractionated into liquid fuels.
– Biomass pyrolysis is a process where biomass (the same feedstocks as for gasification) is converted to liquids through heating the biomass in the absence of oxygen to thermally convert the feedstock to gases, pyrolysis oil and water. The pyrolysis oil is upgraded to final liquid products such as renewable diesel through hydrotreatment and hydrocracking. A hydrogen source is required; typically, the pyrolysis gas is used to supply hydrogen, with or without external supplement.

3.12.11 Levelised comparison between HVO and biodiesel production processes

The levelised production cost of biodiesel is higher than that of crude derived diesel, mainly driven by the price of feedstock. As noted in Section 3.12.8, in 2024, the cost of biodiesel production was approximately $2.00/L, which is approximately 1.2 to 2 times higher than that of crude derived diesel. This is however highly dependent on the price of feedstocks for biodiesel production (animal fats and vegetable oils), as well as the price of crude. This comparison does not include any price on carbon emissions.

In comparison, renewable diesel production has an associated cost that is 2 to 3 times higher than crude derived diesel for renewable diesel produced via the HEFA process from vegetable oils and fats. This is also largely driven by feedstock costs, but also higher capital cost associated with the HEFA process compared to crude oil refining.

Renewable diesel production cost via gasification and Fischer-Tropsch synthesis, pyrolysis and pyrolysis oil upgrading and hydrothermal liquefaction is usually between 4 and 7 or 8 times higher than that of crude derived diesel. The main driver for the high levelised cost of production for renewable diesel via these processes is the high associated capital cost for the production plant, while the feedstock has low or no value attached to it.

3.12.11.1 Hypothetical biodiesel project

Table 3.98 Configuration and performance – Biodiesel

Item	Unit	Value	Comment
Configuration			
Technology		FAME biodiesel process	Includes processing of vegetable oils or animal fats with pre-treatment,

Item	Unit	Value	Comment
			trans-esterification and purification of the biodiesel to a final product.
Feedstock source		Vegetable oils, animal fats	
Make model		Biodiesel OEMs	
Unit size (Nominal)	ML per annum	50	
Number of units		1	
Performance			
Total plant size (Gross)	ML per annum	50	
Biodiesel production	ML per annum	50	Assuming 7,200 hours per annum utilisation
Vegetable oil/tallow feed	ML, tonnes per annum	50 ML, 45 455 tonnes	1:1 conversion from oil feedstocks
Average Planned Maintenance / Seasonal delays	Days / year	65	

Table 3.99 Project timeline – Biodiesel

Item	Unit	Value	Comment
Project timeline			
Time for development	Years	3	Requires time for pre-feasibility, feasibility, design, approvals, procurement and sustainable feedstock procurement
First year assumed commercially viable for construction	Year	2025	
EPC programme	Years	3	
– Total lead time	Years	2	
– Construction time	Weeks	52	
Economic life (Design life)	Years	20	Dependent on feedstock
Technical life (Operational life)	Years	30	

3.12.11.2 Development cost estimates (Hypothetical biodiesel project)

The following table provides CAPEX cost estimates for the defined biodiesel project.

Table 3.100 Development cost estimates – Biodiesel

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$	75,000,000	Based on $50,000,000 CAPEX for Just Biodiesel 50 ML/a plant in 2007 updated with CEPCI, 525.4 (2007) and 800 (2024).
Total EPC cost	$		
– Equipment cost	$	30,000,000	Assumed to be 40% of EPC cost
– Construction cost	$	45,000,000	Assumed to be 60% of EPC cost
Other costs			
Cost of land and development	$	7,500,000	10% of CAPEX assumed
Feedstock supply costs	$ M/annum	N/A	Given the scale of the plant, the feedstock would be delivered by road.

3.12.11.3 O&M cost estimates (Hypothetical biodiesel project)

The following table provides fixed, variable and total annual O&M cost estimates for the defined biodiesel project.

Table 3.101 O&M cost estimates – Biodiesel

Item	Unit	Value	Comment
Fixed O&M cost	$/annum	2,250,000	Assume maintenance is 3% of CAPEX per annum
	$/ML/annum	45,000	
Variable O&M cost	$/ML/annum (Net)	62,400,000 /ML/annum	Assuming a feedstock cost of $1,286/t for UCO and $0.08/L for chemicals, catalysts, utilities
	$/ML	1,248,000/ML/annum	
Total annual O&M cost	$	64,650,000	

3.12.11.4 Retirement cost estimates (Hypothetical biodiesel project)

Retirement costs for the defined biodiesel project are outlined in the table below.

Table 3.102 Retirement cost estimates – Biodiesel

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$ / ML/a	160,000	
Disposal costs	$ / ML/a	N/A	
Recycling costs	$ / ML/a	(10,000)	Assuming 500 t of steel for recycling, at $1.00/kg
Total retirement costs	$ / ML/a	150,000	10% of CAPEX assumed

3.13 Waste to energy plants

3.13.1 Overview

Waste to Energy (WtE) plants refer to the thermal conversion of waste material for power generation and heat. Feedstocks include municipal waste, commercial and industrial wastes, sewage sludge and refuse-derived fuel from sorted waste.

The following processes are considered:

– Waste incineration/combustion, involving direct combustion of waste at high temperature in a boiler to produce steam, which is then utilised for power generation in a traditional steam turbine. Flue gas treatment is required to remove acid gases (mainly SO_2), particulates, NO_x control and heavy metals and dioxin removal. Inorganic/incombustible material in the feedstock reports to ash.

– Gasification of waste, involving thermo-chemical conversion of waste under sub-stoichiometric oxygen conditions to produce a synthesis gas (fuel gas with heating value) composed of hydrogen, carbon monoxide, methane, carbon dioxide, steam and contaminant species. The syngas is treated to remove contaminant species and then routed to a gas turbine for power generation. Inorganic material in the feedstock reports to ash, typically with 1-3% carbon remaining in the ash.

– Waste pyrolysis, involving decomposition of waste in the absence of oxygen at relatively high temperatures to produce pyrolysis gas (fuel gas with heating value), pyrolysis oil and char.

3.13.2 Mass burn technology (incineration of waste)

There are a number of facilities that combust waste directly for energy generation:

– In the EU, there is a reported 498 (2022) [139] waste to energy facilities operating, not including hazardous waste incineration plants. 100 million tonnes of residual waste is thermally treated[140]. Moving grate/grate combustion technology is the dominant technology for mixed MSW in Europe.
– In the US, there are 75 waste to energy (WtE) facilities in various States, with again most of these being grate/mass burn boilers[141]. There are also 10-20 incinerator facilities reported in Canada.
– In Australia, WtE has not been widely adopted, with only 11 facilities either operating or proposed across the country[142].

3.13.3 Gasification of waste

Gasification of wastes is not currently widely adopted globally. This is mainly due to the additional complexity involved in gasification and higher capital cost associated with gasification of wastes. Potential advantages of gasification over incineration include:

– Higher efficiency at 25-35% electrical efficiency compared to 20-25% for incineration processes
– Lower (and easier to treat) emissions
– Better residue quality, particularly if high temperature gasification is selected where the ash is vitrified

Process steps include the following:

– Feedstock preparation, where size reduction of the waste to a particular particle size distribution (PSD) is accomplished and drying is often required
– Gasification reactor, where the waste is heated to 800 to 1,000+°C with sub-stoichiometric oxygen or air and/or steam
– Gas treatment to remove particulates, tars, acid gases, alkali metals. The gas cannot be directly utilised in gas turbines as it could foul the turbines.
– Energy conversion where a gas turbine or combined cycle (gas turbine, HRSG and steam turbine) is used to generate power

There are limited waste gasification and power generation facilities, with Japan being the leading country with more than a 100 small to medium gasification-based WtE plants, accounting for a market share of over 50% in the WtE sector in Japan (gasification and pyrolysis combined)[143]. In other parts of the world, including Australia, only pilot or demonstration facilities have typically been constructed and operated.

3.13.4 Pyrolysis of waste

Pyrolysis of waste could also be considered for power generation. Typically, the reactors are smaller than for gasification, so that smaller scale facilities could be considered, but the downstream treatment of the reactor effluents can be more complex, with oil and gaseous products that must be combusted for power generation. Typically, the pyrolysis products are split with the pyrolysis gas containing 40-50% of the energy converted from the feedstock, the oil 20-30% and the char 20-30%.

Dual fuel engines or a combination of gas turbines and engines could be included for power generation. Both the oil and the gas include contaminants; these are relatively simple to remove from the gas phase stream but difficult to remove from the oil, so that the oil is combusted "dirty".

In Japan and in South Korea some MSW pyrolysis and gasification/pyrolysis hybrid facilities have been in operation since the 2000s, and there have been several demonstration projects in Europe, but in general, waste pyrolysis has not been adopted with success for power generation.

[139] **CEWEP - The Confederation of European Waste-to-Energy Plants.** Website accessed 18/09/2025.
[140] **CEWEP - The Confederation of European Waste-to-Energy Plants.** Website accessed 18/09/2025.
[141] **Energy from Waste: The State of Waste-to-Energy in the US | WMW**. Website accessed 18/09/2025.
[142] **Australia is set to embrace energy from waste, but should it? - ABC News.** Website accessed 18/09/2025.
[143] **Gasification Waste to energy: Lessons from Japan | Klean Industries.** Website accessed 18/09/2025.

3.13.5 Combustion of refuse derived fuel (RDF) in boilers

Refuse-derived fuel (RDF) is prepared from MSW following removal of recyclables and non-combustibles such as glass and metal, as well as drying to a maximum moisture content of 15 mass%. RDF is also sized to produce a relatively uniform PSD feedstock with higher heating value than the raw waste.

3.13.6 Recent trends

The WtE market was valued at US$45.4 billion in 2025 and is expected to grow to US$77.3 billion by 2030. Of this, 55% of the market is geared towards power generation, while some liquid fuels conversion is also included (approximately 20%). Both the fastest growing and largest market is in the Asia Pacific region[144]. Incineration/combustion still has the largest market share, with 65% of the total.

As of early 2024, there were over 2,800 WtE plants globally, with a combined disposal capacity of 576 million tonnes of waste per annum[145]. It is estimated that there will be 3,100 facilities with a capacity of more than 700 million tonnes per annum in total by 2033. The most prevalent technology remains incineration/combustion of waste, with 65-80% of the market. There is increased interest in gasification, pyrolysis and advanced thermal systems, but growth remains slow, mainly due to capital cost constraints.

Drivers for the increased utilisation of wastes for energy generation include:

- Growing emphasis on sustainable urban growth and landfill saturation due to increasing urbanisation.
- Diversion of wastes from landfill and finding alternative uses for these materials.
- Growing emphasis on reduced or zero waste policies by governments and municipalities

There are some factors that may dampen WtE development as well, including:

- Stricter dioxin emissions caps delaying grate-furnace permits in Europe (and Germany specifically), which could also expand to other parts of the world
- Community push back against in particular incineration projects

WtE is being more tightly integrated into broader waste management policies with a focus on reducing the waste materials upstream and separating recyclables. There is an emphasis on reducing life-cycle emissions and combining WtE with other strategies.

Australia has been slow to adopt large WtE projects. There are several proposed plants in various States, with most aiming to utilise moving grate (combustion) technology. The first large scale WtE plant in Australia started up in 2024 at Kwinana in WA, but is not yet performing at nameplate, while the East Rockingham facility has not been commissioned as yet.

3.13.6.1 Summary of changes

A major change from the 2024 report to this report is the OPEX, which is based on a percentage of CAPEX in this report, which is a typical way to express OPEX at this level of estimate. A total of 4% of CAPEX per annum for OPEX is quite typical for this type of facility.

3.13.7 Selected hypothetical project

Most typically, WtE projects involve a combustion process to produce steam in a boiler, which is then utilised for power generation in a traditional steam turbine. Incineration/combustion still has the largest market share, with 65% of the total of WtE plants. The main reasons are simplicity of operation and lower capital cost associated with combustion of wastes compared to other alternatives discussed above.

As the most prevalent type of WtE facility, combustion in a moving grate unit was selected as the basis for the project.

[144] **Waste to Energy Market Size, Trends, Share & Industry Report 2025-2030.** Website accessed 18/09/2025.
[145] **Publications - Waste to Energy 2024/2025.** Website accessed 18/09/2025.

Table 3.103 Configuration and performance – Waste to energy combustion case

Item	Unit	Value	Comment
Configuration			
Technology		Sub-critical boiler	Combustion of waste in a moving grate combustor
Fuel source		MSW	
Make model		Western OEM	Includes Doosan Lentjes and Martin GmbH.
Unit size (Nominal)	MW	30.0	
Number of units		1.0	
Steam pressure	MPag	7.0	
Steam temperature	°C	470	
Condenser pressure	kPaa	7.2	
Performance			
Total plant size (Gross)	MW	30.0	Climatic conditions are 25°C, 110 m above sea level, 60% RH
Auxiliary power consumption	%	12.0	
Total plant size (Net)	MW	26.4	
Seasonal rating – Summer (Net)	MW	25.7	
Seasonal rating – Not Summer (Net)	MW	26.8	
Heat rate at minimum operation	(GJ/MWh) HHV Net	19.9	
Heat rate at maximum operation	(GJ/MWh) HHV Net	15.4	
Thermal Efficiency at MCR	%, HHV Net	23.4	
Annual Performance			
Average planned maintenance	Days / year	22.8	
Equivalent forced outage rate	%	4.0	
Annual capacity factor	%	89.8	
Annual generation	MWh / year	207,675	
Annual degradation over design life – Output	%	1-2% over the first 18 months and then flat/low degradation	
Annual degradation over design life – Heat rate	%	0.2	

Table 3.104 Technical parameters and project timeline – Waste to energy combustion case

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW / min	1.2	Based on 3%/min ramp rate
Ramp down rate	MW / min	1.2	Based on 3%/min ramp rate
Start-up time	Min	Cold: 420 Hot: 60	
Min stable generation	% of installed capacity	40	Without oil support
Project timeline			
Time for development	Years	3-4	

Item	Unit	Value	Comment
First year assumed commercially viable for construction	Year	2025	
EPC programme	Years	3	
– Total lead time	Years	1.75	
– Construction time	Weeks	65	
Economic life (Design life)	Years	25	
Technical life (Operational life)	Years	30	

3.13.8 Development cost estimates

The following table provides CAPEX cost estimates for the defined waste to energy project.

Table 3.105 Development cost estimates – Waste to energy combustion case

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$/kW (Net)	25,797	Escalated from 2024 report[146]
Total EPC cost	$	681,027,600	
– Equipment cost	$	408,616,560	Assume 60% of EPC cost
– Construction cost	$	272,411,040	Assume 40% of EPC cost
Other costs			
Cost of land and development	$	68,102,760	Assume 10% of CAPEX
Fuel connection costs	$	N/A	Waste is assumed to be delivered by road transport.

3.13.9 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined waste to energy project.

Table 3.106 O&M cost estimates – Waste to energy combustion case

Item	Unit	Value	Comment
Fixed O&M cost	$/MW/year (Net)	773,895	3% of CAPEX per annum assumed
Variable O&M cost	$/MWh (Net)	32.8	1% of CAPEX per annum assumed. Includes consumables, auxiliary fuel, lubricants. Excludes fuel costs
Total annual O&M cost	$	27,241,104	

3.13.10 Retirement cost estimates

Retirement costs for the defined waste to energy project are outlined in the table below.

Table 3.107 Retirement cost estimates – Waste to energy combustion case

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	150,000	
Disposal costs	$/MW (Net)	2,000	

[146] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024

Item	Unit	Value	Comment
Recycling costs	$/MW (Net)	(11,400)	Assuming 3,000 t of steel to be salvaged at $1/kg
Total retirement costs	$/MW (Net)	140,600	

4. Hydrogen based technologies and storage

4.1 Overview

The following sections outline the typical options, recent trends, technical parameters, and cost parameters for each of the nominated hydrogen-based technologies and storage. The information listed within the respective tables has been used to populate the AEMO GenCost 2025 Excel spreadsheets in Appendix A.

Hydrogen is a potential low carbon fuel for transport, reducing agent for iron and steel production, feedstock for ammonia production or liquid transport fuels, and it could be blended with natural gas for distribution in existing natural gas pipelines. It also offers potential for energy storage however round-trip efficiency with current technology is relatively low.

The following hydrogen-based technologies are addressed in this section:

– Reciprocating engines and gas turbines (including hydrogen conversion of gas turbines) are discussed but mainly addressed elsewhere in the report
– Electrolysers for the production of low carbon hydrogen from water electrolysis and renewable power
– Hydrogen fuel cells (small and large)
– Steam methane reforming, with and without carbon capture and storage
– Hydrogen storage
– Ammonia production facility
– Desalination plant
– Water treatment (demineralisation) for hydrogen production
– Hydrogen fuel cells (large and small scale)
– Steam methane reforming of natural gas and carbon capture for low carbon hydrogen production
– Compressed gaseous hydrogen storage
– Hydrogen liquefaction and liquid hydrogen storage
– Geological hydrogen storage
– Ammonia production (hydrogen stored in a carrier)

4.2 Reciprocating engines

Refer to Section 3.9 for a general overview and presentation of costs for reciprocating engines.

With regards to the use of hydrogen in reciprocating engines, there is a shift to incorporate low emissions fuels with natural gas as a feedstock to reciprocating engines. The transition primarily involves fuel blending strategies and hydrogen firing capabilities, with new installations typically designed to accommodate hydrogen concentrations ranging from 10 vol% to 100 vol%[147].

Without major modifications up to 10-20 vol% hydrogen could be blended into the natural gas feedstock for reciprocating engines. Beyond this point, the blend is limited by knock and pre-ignition. NO_x emissions increase with increased hydrogen in the feed blend, and additional mitigation measures may be required beyond a 20 vol% blend. With advanced controls and cooling some engines can handle up to 30-40 vol% hydrogen in the natural gas feed blend. Materials of construction have to be compatible with hydrogen embrittlement risk. Carbon steels may not be suitable at higher hydrogen blends.

Technology suppliers have tested hydrogen/natural gas blends, and can be designed to run on a certain percentage of hydrogen with natural gas, or even up to 100 vol% hydrogen:

– Caterpillar provides generator sets capable of running on up to 25 vol% hydrogen blends, as well as dedicated 100% hydrogen-powered systems (G3516H)[148]. Caterpillar sees two parallel paths for hydrogen

[147] **Wärtsilä succeeds in world's first hydrogen blend test - Wärtsilä Energy**
[148] **Hydrogen-based Cat® Power Generation Solutions | Cat | Caterpillar.** Website accessed 23/09/2025.

use[149]; (1) blending of hydrogen with natural gas to create up to a 25 vol% mixture making use of installed storage and distribution capacity. Most boilers and other consumers of natural gas would not require modifications to equipment at such blending levels, and (2) the use of 100% or nearly 100% hydrogen at dedicated locations, requiring specialised generator sets and infrastructure.

– Jenbacher has engines that can run on up to 25 vol% and 60 vol% hydrogen blends and also offers 100% hydrogen engine solutions[150].
– Wartsila has tested up to 25 vol% hydrogen in NG blend[151] using an engine in commercial operation. The report was released in 2023. Engine efficiency was not significantly impacted by hydrogen fuel blending, and greenhouse gas emissions were reduced with the exception of NOx, which was controlled through an existing SCR system.

4.3 Gas turbines, including hydrogen conversion of gas turbines

Refer to Section 3.11 for typical operation of gas turbines and costs involved. With regards to hydrogen conversion of gas turbines, 20-30 vol% hydrogen in NG blends have been tested in gas turbines, with limited hardware changes required. Several OEMS have completed test work at higher concentration hydrogen blends, with Mitsubishi testing up to 30 vol% in a demonstration[152] and Georgia Power/Mitsubishi testing up to 50 vol%[153] successfully. Siemens has tested up to 100% hydrogen using their HYFLEX SGT-400[154]. It does not appear that any gas turbines have been consistently run on hydrogen blends or hydrogen fuel beyond demonstrations in commercial settings, mainly due to limited hydrogen supply.

The following challenges are observed with hydrogen blends/hydrogen fuel to a gas turbine, including higher NO_x emissions, hydrogen's higher flame speed which risks flashback so that burner geometry and dilution strategies have to be modified, and materials have to be selected for hydrogen embrittlement and there is an increased leak risk due to the nature of hydrogen compared to natural gas.

4.4 Electrolysers

4.4.1 Overview

According to the International Energy Agency (IEA), electrolysis installed capacity globally reached 1.4GW at the end of 2023, almost double that from at the end of 2022[155]. China has the highest installed electrolyser capacity, with over half of global committed renewable hydrogen capacity. However, since 2023, progress has been slower than expected.

From the Global Hydrogen Compass 2025 published by the Hydrogen Council, committed investment in clean hydrogen has surpassed US$110 billion in 2025[156], with more than 1,700 clean hydrogen projects announced globally across the value chain. Maturation of the project pipeline has resulted in fewer new announcements. There is an estimated 1 mtpa of clean hydrogen capacity that is operational, while an additional 5 mtpa has reached Final Investment Decision (FID) or is under construction. One of the critical elements for hydrogen projects to move forward is locking in off-take agreements. Approximately 3.6 mtpa of binding off-take agreements are currently in place.

[149] Hydrogen-Based Cat® Power Generation Solutions | Cat | Caterpillar. Website accessed 23/09/2025.
[150] Hydrogen Power Plants | Energy Solutions | Jenbacher. Website accessed 23/09/2025.
[151] Executive_Summary_Hydrogen_Blending_Demonstration_Wartsila50SG.pdf (SECURED). Website accessed 23/09/2025.
[152] Mitsubishi Power demonstrates 30% H2 in a JAC gas turbine - Modern Power Systems. Website accessed 23/09/2025.
[153] 50% hydrogen blend testing successfully completed at Georgia Power's Plant McDonough-Atkinson. Website accessed 23/09/2025.
[154] World first: Gas turbine successfully operates with 100% green hydrogen. Website accessed 23/09/2025.
[155] Electrolysers - Energy System - IEA. Website accessed 19/09/2025.
[156] Hydrogen-Council-Global-Hydrogen-Compass-2025_Final.pdf. Website accessed 19/09/2025.

4.4.2 Typical options

The following options exist commercially for electrolyser technology:

- Alkaline electrolysis, where the reaction to produce hydrogen ($2H_2O$ (l) $\rightarrow$ $2H_2$ (g) + O_2 (g)) occurs in a solution of water and liquid electrolyte (potassium hydroxide – KOH) between two electrodes. This is an established technology and has been in commercial operation for a number of decades. Vendors for this type of technology include NEL[157], John Cockerill, ThyssenKrupp Nucera and Peric. Alkaline electrolysers are the most mature electrolyser technology in the market today, representing the lowest technical risk.
- Proton Exchange Membrane (PEM) electrolysers use a solid polymer to split water into hydrogen and oxygen. Water enters the cell, and an electrical current separates it at the anode, producing oxygen, electrons, and positively charged hydrogen ions (protons). These protons pass through the membrane to the cathode, where they combine to form hydrogen gas. The system is built with layers that manage water flow, collect gases, conduct electricity, and keep the unit cool. Vendors include NEL, Plug Power[158] and Siemens Energy[159].
- Solid Oxide Electrolyser Cells (SOECs) are a newer type of commercially available electrolyser technology. They operate at higher temperatures than other technologies, using steam to improve efficiency (refer to the electrolyser efficiency comparison below). As a result, they require less electricity to produce hydrogen compared to traditional alkaline or PEM electrolysers. Leading suppliers of SOECs include Bloom Energy[160] and Topsoe[161]. SOEC technology selection makes sense when a site has excess steam available; that is, integration with a refinery or similar industrial application is advantageous for these units.

A brief comparison of the three commercially available technologies follows.

Efficiency

Alkaline electrolysers are more efficient than PEM units, at an average stack consumption of 50kWh/kg of hydrogen produced[162] compared to 54kWh/kg for the PEM. Even accounting for compression requirement for alkaline electrolysers to match the outlet pressure of the PEM (approx. 2kWh/kg), alkaline electrolysis is more efficient at 52kWh/kg[163]. The stack efficiencies quoted here are all at Beginning of Life (BOL).

SOEC is the most efficient electrolyser technology currently at an average efficiency of 35-40 kWh/kg hydrogen[164, 165]. This is because of the high temperature electrolysis process, where the energy required to break a water vapour molecule is lower compared to a liquid water molecule. However, its stack efficiency does not account for energy needed to produce steam at 700-800ºC for the process to occur if a waste heat stream is not available. The theoretical amount of energy needed to produce steam at 800ºC from water at 25ºC is 1.1kWh/kg[166], and the SOEC typically requires ~10 kg of steam for 1 kg of hydrogen[167], so that ~11kWh/kg of H_2 of extra energy needs to be added to the stack consumption to appropriately account for the requirement to generate steam. Adding the 11kWh/kg of energy to the average cell stack energy consumption would bring the energy requirement to 51kWh/kg, slightly higher than the alkaline electrolyser. SOEC efficiency is therefore attractive when a suitable source of steam is available.

Electrolyser package footprint

A PEM 10MW electrolyser module has the smallest footprint at around 600m^2 with current designs of the alkaline and SOEC 10MW modules taking up approximately 1200m^2 and 1150m^2 respectively.[168, 169]

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[157] **Water electrolysers / hydrogen generators | Nel Hydrogen.** Website accessed 19/09/2025.
[158] **Home - Plug Power.** Website accessed 19/09/2025
[159] **Green hydrogen production.** Website accessed 19/09/2025.
[160] **An Efficient Electrolyzer for Clean Hydrogen - Bloom Energy.** Website accessed 19/09/2025.
[161] **Efficient SOEC electrolysis for green hydrogen production.** Website accessed 19/09/2025.
[162] **Alkaline Water Electrolysis Powered by Renewable Energy: A Review | MDPI.** Website accessed 14/11/2025.
[163] Data averaged for a number of electrolyser vendor packages from GHD internal database.
[164] **IRENA_Green_hydrogen_cost_2020.pdf.** Website accessed 14/11/2025.
[165] **SOEC high-temperature electrolysis factsheet.pdf.** Website accessed 14/11/2025.
[166] HYSYS modelling results. Produced by GHD on 10/11/2025.
[167] **SOEC high-temperature electrolysis factsheet.pdf.** Website accessed 14/11/2025.
[168] Data averaged for a number of electrolyser vendor packages from GHD internal database.
[169] **IRENA_Green_hydrogen_cost_2020.pdf**. Website accessed 14/11/2025.

Stack degradation

Both the PEM and alkaline units have degradation rates in efficiency of approx. 1% p.a. over the life of the cell stack[170]. The degradation for SOEC is less understood but is expected to be considerably faster than for PEM and alkaline electrolysis. Work is ongoing to reduce the degradation of SOEC cells and improve their lifetime[171,172].

Operating envelope

PEM electrolysers typically have the widest operating envelope, the quickest load change response times and the quickest start up and stop times. A PEM operating window is 5-130% which allows the electrolyser to run over nameplate capacity by 30% for periods of time with minimum turndown of the systems as low as 5%[173]. PEM systems are generally considered to be most suitable to handling a variable input load, i.e., a renewable energy generation, due to their short response times. A PEM could be started and at full load from warm conditions within 0.02-5 minutes depending on how long it has been offline for.

Alkaline systems have a narrower operating range of 15-100%[174] with a minimum turndown of 15%. They are generally slow to turn up/down and start/stop from cold or warm, compared to a PEM system. Alkaline systems will start up from warm conditions in 1-10 minutes and from cold in 20-60 minutes[175, 176].

SOEC systems have an operating range of 5-125%[177] with a minimum load of 5-20%. At the minimum load the efficiency of the electrolyser cell drops significantly. They have similar response times to alkaline systems when ramping to and from minimum load however unlike the alkaline or PEM systems, SOECs are not designed to be shut down and restarted regularly. This is due to the requirement to operate at temperatures in excess of 700°C. If an SOEC cell needs to be shut down the potential start up time from cold is 10-16 hours depending on the starting temperature of the cell stack[178]. This is because the system temperature can only be increased at 50°C/hr to protect the components from thermal stresses due to heating or cooling the equipment too quickly.

Technology maturity

The International Energy Agency (IEA) has ranked both AEC and PEM technologies as mature technologies. Alkaline electrolysers are the most mature hydrogen electrolysis technology having been in use at commercial scale since the 1930's[179]. PEM systems have developed over recent years and are also now considered mature. Both technologies are now proven at scale and there is continued development to enhance the efficiency, reliability and longevity of each of these technologies.

SOEC as a technology is mostly under demonstration with Bloom Energy's SOEC undergoing testing at the Idaho National Lab[180]. Sunfire are currently in the process of delivering the largest SOEC at 2.6MW at Neste's Renewable products refinery in Rotterdam[181]. Haldor Topsoe have also announced plans to build a 500MW SOEC manufacturing facility to support the supply of SOEC units into the market[182].

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170 **02-05_nrel_harrison_public.pdf.** Website accessed 14/11/2025.
171 **Performance and degradation of an SOEC stack with different cell components - ScienceDirect**
172 **IRENA_Green_hydrogen_cost_2020.pdf.** Website accessed 14/11/2025.
173 **Water electrolysis: from textbook knowledge to the latest scientific strategies and industrial developments - PMC**. Website accessed 14/11/2025.
174 **Atmospheric Alkaline Electrolyser – Nel Display.** Website accessed 14/11/2025.
175 **Water electrolysis: from textbook knowledge to the latest scientific strategies and industrial developments - PMC.** Website accessed 14/11/2025.
176 Information gathered from electrolyser vendors, GHD internal library information.
177 **Water electrolysis: from textbook knowledge to the latest scientific strategies and industrial developments - PMC**. Website accessed 14/11/2025.
178 **Water electrolysis: from textbook knowledge to the latest scientific strategies and industrial developments - PMC.** Website accessed 14/11/2025.
179 **Alkaline Electrolysers 101: Everything You Need to Know About the most reliable hydrogen production technology.** Website accessed 14/11/2025.
180 **Idaho National Lab and Bloom Energy Produce Hydrogen at Record-Setting Efficiencies - Bloom Energy**
181 **World's Largest High-Temperature Electrolysis Module Deliveries Started - Sunfire**
182 **'World's largest' | Topsoe plans 5GW solid-oxide hydrogen electrolyser factory as it signs off first 500MW | Recharge (rechargenews.com)**

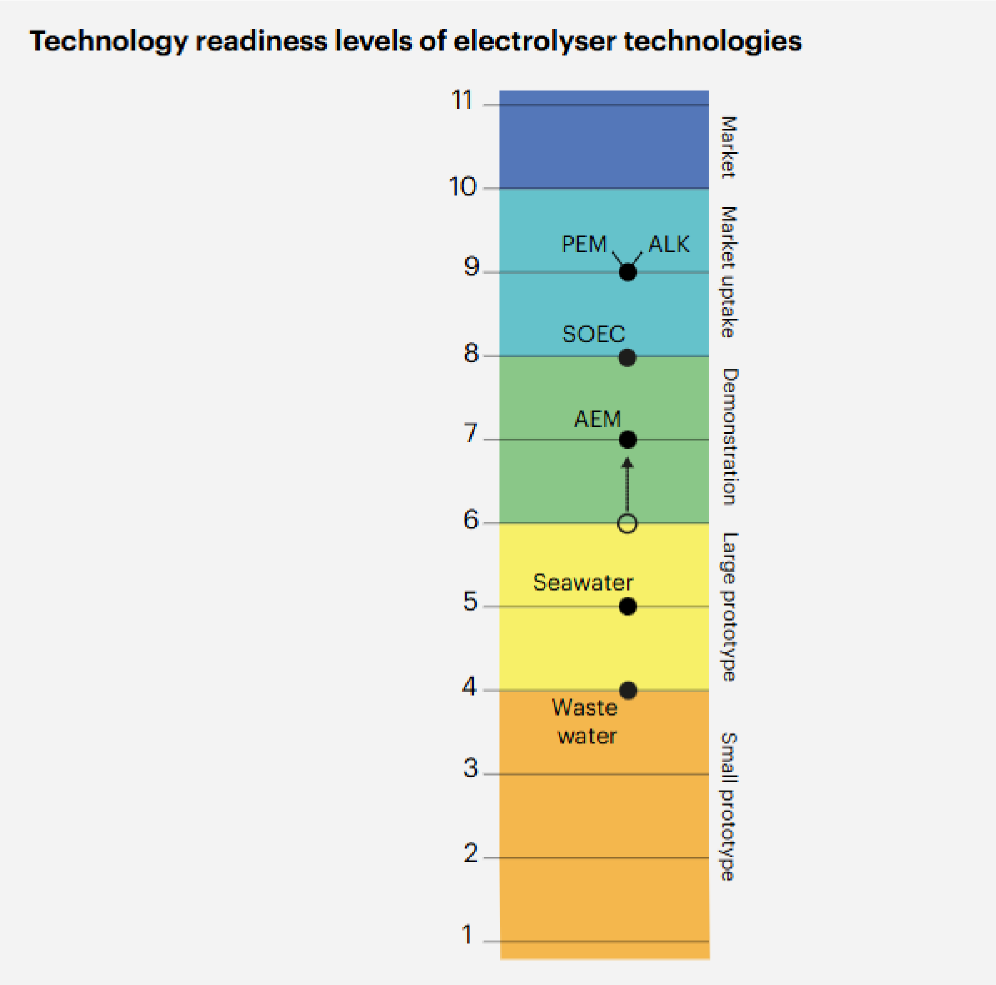


Figure 4-1 International Energy Agency (IEA) TRL ratings for various electrolyser technologies[183]

There are a number of emerging electrolyser technologies, typically at relatively low Technology Readiness Level (TRL), however, some of these could offer some potential advantages over current commercially available technologies. These include Anion Exchange Membrane (AEM) electrolyser, which is similar to PEM, but uses an anion-conducting polymer membrane and runs in alkaline conditions. It uses low-cost catalysts (similar to alkaline units) but also has a compact design and high current density (similar to PEM units). Vendors for this type of technology include Enapter[184] and Versogen[185]. The TRL for AEM is 6-7.

In Australia, Hysata[186] is developing a high temperature high efficiency electrolyser system in Australia with high cell efficiency eliminating the need for cooling, with an integrated balance of plant and stack design. The company claims an efficiency of 41.5kWh/kg H_2 for their alkaline capillary-fed electrolyser unit. Once their 5MW unit has been designed, constructed and operated[187], it is expected that the technology will be at a TRL of 8-9.

Another promising technology is the high-pressure electrolyser, which is a variant of AEL or PEM where hydrogen is produced at 30-100 barg, or in some cases up to 200 barg, eliminating the need to compress the hydrogen downstream. NEL Hydrogen is currently conducting research and development work on such electrolysers.

[183] **Electrolysers - Energy System - IEA**
[184] **Home - Enapter.** Website accessed 19/09/2025.
[185] **Versogen - Producing Low-Cost Green Hydrogen at Scale.** Website accessed 19/09/2025.
[186] **Our Technology – Hysata**
[187] **Hysata Capillary-fed' Electrolyser Commercial-Scale Demonstration Project - Australian Renewable Energy Agency (ARENA)**

4.4.3 Recent trends

There are some electrolysers under construction or in operation in Australia. Engie's Yuri Renewable Hydrogen to Ammonia Project is on track for completion in 2025 and includes 10 MW of installed electrolyser capacity[188]. As of June 2025, it had not been commissioned[189]. Australian Gas and Infrastructure Group's (AGIG) Hydrogen Park Murray Valley is also progressing and under construction, with operations expected in 2026[190]. This project also includes 10MW of electrolysis capacity. The Australian government announced an additional $2 billion for Hydrogen Headstart (Round 2 of the Hydrogen Headstart program) as part of the 2024-25 federal budget, bringing it to a total of $ 4 billion of support. Headstart will provide revenue support for large-scale renewable hydrogen projects through competitive hydrogen production projects.

However, the hydrogen industry, both in Australia and globally, has grown more slowly than expected. Reasons for this include high production costs, and in particular high costs for firm renewable power, which accounts for 50+% of the total cost of hydrogen production from electrolysis in most cases. In addition to that, weak demand certainty is a challenge, with many hydrogen users not willing or able to commit to buying large volumes of low carbon hydrogen at premium prices. There are geopolitical conditions that are counter-productive to a hydrogen economy, including high inflation rates, energy price volatilities and policy changes in particular the US with regards to low carbon initiatives.

Several large-scale projects have been cancelled or delayed due to financial challenges, including Fortescue's 500 MW Gibson Island project, the South Australian Hydrogen Jobs Plan including development of a 250 MW facility in Whyalla, South Australia[191], and the 3 GW H2-Hub Gladstone. Additionally, key proposals under the Hydrogen Headstart Program—such as H2Kwinana, Stanwell's Central Queensland Hydrogen Project, and Origin Energy's Hunter Valley Hub—are no longer proceeding.

Slow progress in project delivery has stalled technology development, keeping costs high and limiting efficiency gains. Some OEMs claim step-change improvements, but these are not yet widespread. The emergence of SOEC technology may help reduce the levelised cost of hydrogen, particularly when paired with facilities that can supply excess steam. However, SOECs are less suited to variable operations due to their sensitivity to thermal cycling.

Efforts continue to improve hydrogen storage and compression technologies, as well as the production of hydrogen-derived fuels like ammonia, methane, and methanol. These can serve as both carriers and end-use products.

4.4.3.1 Summary of changes

Compared with 2024 data, for electrolysers the following changes are observed:

- Based on GHD experience and benchmarking against vendor information, the CAPEX for alkaline electrolysers was adjusted to approximately 80% of the CAPEX reflected in the 2024 report, while the PEM-based plant had very similar CAPEX.
- Based on GHD experience and benchmarking against vendor information, the fixed OPEX for PEM electrolysers was adjusted to 2.5% of CAPEX/annum, rather than 2% as per the 2024 report. As a result the OPEX is approximately 24% higher in this Report compared to the 2024 report. Based on GHD experience and benchmarking against vendor information, the fixed OPEX for alkaline electrolysers remains at 2% of CAPEX/annum, which is similar to the percentage used in the 2024 report, but due to the lower CAPEX used here, the OPEX is 20% lower than in the 2024 report.

[188] **Australia's first large scale renewable hydrogen plant to be built in Pilbara - Australian Renewable Energy Agency.** Website accessed 30/04/2025.
[189] **Yuri-Technology-Market-Report-Rev-0-Public.pdf.** Website accessed 19/09/2025.
[190] **Hydrogen Park Murray Valley – HyResource.** Website accessed 19/09/2025.
[191] **Whyalla's Hydrogen Plant Plans Deferred for Steelworks.** Website accessed 30/04/2025.

4.4.4 Selected hypothetical project

Table 4.1 Configuration and performance – Electrolysers

Item	Unit	Value	Comment
Configuration			
Technology		Alkaline electrolyser	Best-developed commercial technology, lower cost than PEM/SOEC
Unit size (Nominal)	MW	10	
Number of modules		50	
Performance			
Total plant size	MW	500	
Auxiliary power consumption	%	5	Typically 5-7%. Excludes compression
Seasonal rating – Summer (Net)	MW	500	Stack capacity
Seasonal rating – Not Summer (Net)	MW	500	Stack capacity
Efficiency	%	75.5	HHV basis at Beginning of stack Life (BoL), based on average of alkaline vendor information
Efficiency	kWhe/kg H_2	54.0	Stack efficiency at End of Life (EoL). Range from 52.2 – 54.0 kWh/kg H_2
Hydrogen production rate	kg/h	9,260 (185.2 per unit)	Maximum hydrogen production rate
Output pressure	Bar	Atmospheric	For alkaline units, atmospheric to 20 barg
Additional compression power	kW	24,705	Compressing hydrogen to 100 barg
Life cycle design	Hours	80,000	Stack operating life. Stacks are typically replaced and production continues.
Water consumption	L/kgH_2	12-15	Raw water consumption to produce demineralised water for electrolysis. Excludes cooling water demand. Air-cooled systems are typically selected for electrolysis.
Annual Performance			
Average planned maintenance	Days / year	15	Includes consideration for stack replacement (averaged over the lifetime of the project).
Equivalent forced outage rate	%	3	
Annual degradation	%	0.5 – 1.0	Typical degradation

Table 4.2 Technical parameters and project timeline – Electrolysers

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate		20%/minute	Typical for alkaline, PEM has a much faster response time
Ramp down rate		20%/minute	Typical for alkaline, PEM has a much faster response time
Start-up time	Min	Cold start: 60 min Warm start: 5 min	Typical for alkaline, PEM has a much faster response time

Item	Unit	Value	Comment
Min stable generation	% of installed capacity	10	Turndown for alkaline electrolysers range from 10-20% of installed capacity
Project timeline			
Time for development	Years	5	
First year assumed commercially viable for construction	Year	2025	
EPC programme	Years	5	
– Total lead time	Years	1.5	Electrolyser packages currently have a lead time of at least 18 months
– Construction time	Weeks	52	Up to 52 weeks
Economic life (Design life)	Years	20	Assuming major overhaul (stack replacement) takes place after roughly 10 years
Technical life (Operational life)	Years	20	

The timeline for a hydrogen project is based on the current understanding of electrolyser lead times, which are around 18 months, and more likely up to 36 months, time for power connections and time required for renewable power supply agreements. Large/multiple electrolyser facilities do not yet exist, and therefore it is foreseen that significant engineering effort will be required for the first number of facilities, extending the initial project development schedule.

4.4.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined electrolysers.

Table 4.3 Development cost estimates – Electrolysers

Item	Unit	PEM	Alkaline	Comment
CAPEX – EPC cost				
Relative cost	$/kW	2,600	2,000	Assuming 500MW electrolyser capacity, hydrogen compression, water treatment and supporting utilities and buffer hydrogen storage. Based on typical electrolyser vendor package costs.
Total EPC cost	$	1,300,000,000	1,000,000,000	
– Electrolyser package cost	$	520,000,000	370,000,000	
– BOP & construction cost	$	780,000,000	630,000,000	
Other costs				
Cost of land and development	$	65,000,000	50,000,000	Assumed to be 5% of CAPEX
Fuel connection costs	$	N/A	N/A	
Hydrogen compressor	$	24,600,000	95,400,000	
Hydrogen transport	$ / kilometre	960,000/km	960,000/km	Assuming a DN200 pipeline to transfer a maximum of 9.4 t/h hydrogen at a maximum linear velocity of 10m/s. Density of H_2 at 30°C and 100 barg is 9.4kg/m^3. Assumed pricing is $120,000/inch/km installed pipeline cost.

Typical capital cost breakdowns for alkaline electrolysers are presented in Figure 4-2.

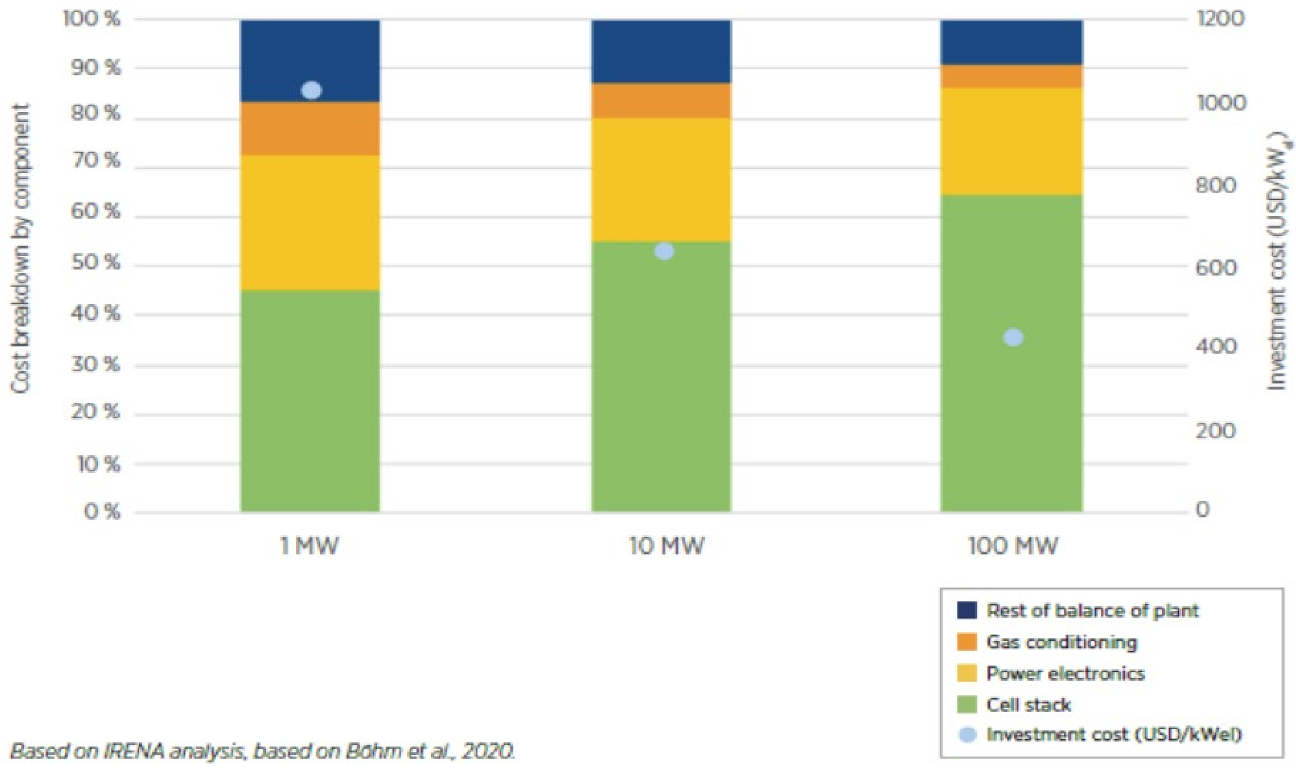


Figure 4-2 CAPEX breakdown for alkaline electrolysers[192]

Cell stack costs represent approximately 55% of the total CAPEX for a 10 MW alkaline unit and 65% for 100 MW of installed electrolyser capacity.

It is expected that the cell stack costs are a higher percentage of the total CAPEX for PEM units, given that the materials of construction are considerably more expensive for PEM units compared to alkaline electrolysers. For alkaline units, the stacks predominantly consist of nickel and nickel-coated steel, while PEM electrolysers use titanium and noble metals such as platinum and iridium.

4.4.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined electrolysers.

Table 4.4 O&M cost estimates – Electrolysers

Item	Unit	PEM	Alkaline	Comment
Fixed O&M cost	$/MW/year (Net)	65,000	40,000	PEM O&M cost is typically 2.5% of CAPEX/annum, alkaline O&M cost is typically 2.0% of CAPEX/annum
Variable O&M cost	$/MWh (Net)	Included in above	Included in above	
Total annual O&M cost	$	32,500,000	20,000,000	Excludes power and water costs

[192] **2024-Juni-4-V03-Masterclass-WHB_-Greenskill4h2_Green-Hydrogen-Cost-and-reduction.pdf**. Website accessed 13/11/2025.

4.4.7 Retirement cost estimates

Retirement costs for the defined electrolysers are outlined in the table below.

Table 4.5 Retirement cost estimates – Electrolysers

Item	Unit	PEM	Alkaline
Decommissioning, demolition & rehabilitation costs	$ / MW (Net)	263,000	246,000
Disposal costs	$ / MW (Net)	5,000	5,000
Recycling costs	$ / MW (Net)	(157,500)	(77,500)
Total retirement costs	$ / MW (Net)	**110,500**	**173,500**

4.5 Hydrogen fuel cells

4.5.1 Overview

A fuel cell converts chemical energy directly into electricity through an electrochemical reaction—most commonly using hydrogen as the fuel and oxygen as the oxidizer. Unlike batteries, fuel cells don't need recharging and can produce electricity continuously as long as fuel is supplied. A Proton Exchange Membrane (PEM) fuel cell consists of three main components:

- Anode (negative electrode), where hydrogen gas is introduced: Hydrogen gas is introduced here. A catalyst splits hydrogen molecules into protons and electrons.
- Electrolyte which sits between cathode and anode and allows only protons to pass through to the cathode.
- Cathode (positive electrode), where oxygen is introduced.

Electrons travel through an external circuit (creating electricity), while the protons pass through the electrolyte and combine with oxygen and electrons to form water and heat

Hydrogen has diverse applications, including natural gas blending, ammonia and synthetic fuels production, mobility, and fuel cells for zero-emission stationary power generation.

However, only a small share of hydrogen projects currently use fuel cells for stationary power, typically in small, off-grid or behind-the-meter arrangements where high integrity power supply is required. Fuel cells can be used to provide primary power and/or backup supply to users such as remote communities, universities, data centres, and hospitals, representing a lower carbon replacement for diesel generators.

4.5.2 Typical options

There are a range of fuel cell technologies available, including the following:

- PEMFC (Proton Exchange Membrane Fuel Cell): Uses a polymer membrane and platinum catalyst. Operates at 40–60% efficiency and can handle rapid power fluctuations. TRL of 9.[193]
- MCFC (Molten Carbonates Fuel Cell): a high temperature process where the electrolyte is made up of alkali carbonates. TRL of 9.
- AFC (Alkaline Fuel Cell): Uses an alkaline-saturated porous electrolyte and membrane, with ~60% efficiency. TRL of 8-9.
- PAFC (Phosphoric Acid Fuel Cell): Employs liquid phosphoric acid and ceramic electrolyte. Suitable for high-demand sites like hospitals and manufacturing facilities. TRL of 9.
- SOFC (Solid Oxide Fuel Cell): High-temperature operation with a solid ceramic electrolyte. Used in both small and large-scale stationary and cogeneration systems. TRL of 9.

Fuel cell stack capacities are by necessity relatively small due to hydraulic and similar limitations, varying from single digit kW to single digit MW in scale. However, like electrolysers, these can be combined to achieve higher capacities. They often have a containerised form factor.

[193] **https://publications.jrc.ec.europa.eu › JRC139352**

4.5.3 Recent trends

Stationary fuel cell adoption has grown rapidly, with global capacity reaching 1.6 GW by 2018 and over 2GW by 2024, with approximately 345MW installed in 2023 and over 400MW projected for 2024[194] —though in 2018 only around 70 MW was hydrogen-fuelled. Leading tech companies like Apple, Google, IBM, Microsoft, and Yahoo have installed small-scale hydrogen fuel cells, with some progressing to megawatt-scale systems for operational power. Proton Exchange Membrane Fuel Cells (PEMFC) represent the majority of units by count[195].

In 2020, Hanwha Energy launched the world's largest hydrogen-only industrial fuel cell plant (50 MW) in South Korea, powered by recycled hydrogen from petrochemical processes[196]. In the U.S., Toyota and NREL partnered to deploy a 1 MW PEM fuel cell system at NREL's Flatirons Campus[197].

Bloom Energy's solid oxide fuel cell platform, capable of running on hydrogen, biogas, or natural gas, has been scaled to 1 MW at Ferrari's manufacturing site in Italy, offering flexible fuel options.

TECO 2030's fuel cell technology includes a modular system with 400kW capacity.

In Asia, MW-scale hydrogen fuel cells are being explored for data centre backup and continuous power. In Australia, deployments remain mostly pilot-scale, such as:

– **Griffith University (Brisbane)**: 2 x 30 kW hydrogen fuel cell since 2013[198].
– **ATCO's Clean Energy Innovation Hub (Jandakot, WA),** opened in 2019, 5kW stationary fuel cell[199]

Wider adoption will depend on affordable hydrogen supply and declining fuel cell costs, driven by global scale-up and technology maturation. Ballard and ABB have announced collaboration around joint development of PEM fuel cell systems, and Siemens Energy and Air Liquide are working together on manufacturing of PEM components.

4.5.3.1 Summary of changes

Compared to 2024 reporting, small scale fuel cell capacity has been reduced, leveraging available OEM information and offering greater differentiation between small and large scale. Fuel cell peak capacity has been updated to reflect this OEM data and the peak capacity is slightly higher than reported previously. Minimum production is 25% of nameplate, in line with an OEM datasheet, is higher than previously quoted.

Economic life has been reported as 20 years rather than the 8 years previously stated, on the basis that stack replacements are a part of routine major maintenance and do not necessarily define the operational life of a facility. CAPEX is similar to the previous large-scale system on a per-kW basis, but is more weighted towards installation costs as per typical industry breakdown for packaged plants.

4.5.4 Selected hypothetical project

Given the large number of PEM systems in the field, PEMFC technology has been chosen for the hypothetical project. To differentiate between small and large scale, a single, relatively small unit has been selected alongside a larger installation comprising multiple larger units.

Table 4.6 Configuration and performance – Hydrogen fuel cells

Item	Unit	Small	Large	Comment
Configuration				
Technology		PEMFC	PEMFC	
Make		Ballard	Ballard	
Unit size (Nominal)	MW	0.045	0.2	
Number of units		1	6	

[194] IEA-AFC-TCP-Annual-Report-2024.pdf
[195] IEA-AFC-TCP-Annual-Report-2024.pdf
[196] Hanwha Energy Celebrates Its Completion of the World's First and Largest Byproduct-Hydrogen-Fuel-Cell Power Plant
[197] Toyota, NREL Collaborate to Advance Megawatt-Scale Fuel Cell Systems - Toyota USA Newsroom
[198] Sir Samuel Griffith Centre – HyResource
[199] Hydrogen Fuel Cell | ATCO Gas Australia

Item	Unit	Small	Large	Comment
Performance				
Total plant size (Gross)	MW	0.045	1.2	
Auxiliary power consumption	%	10%	10%	Per Ballard small scale system[200]
Total plant size (Net)	MW	0.041	1.08	Net of auxiliary consumption
Seasonal rating – Summer (Net)	MW	0.041	1.08	Assume oversized inverter to account for the majority of de-rating attributable to high ambient temps
Seasonal rating – Not Summer (Net)	MW	0.041	1.08	
Thermal Efficiency	%, HHV Net	57% peak	53.5% peak	
Hydrogen consumption at design	Kg/h	2.8	75	
Annual Performance				
Average planned maintenance	Days / year	7	7	Typical industry benchmark
Equivalent forced outage rate	%	Included above	Included above	

Table 4.7 Technical parameters and project timeline – Hydrogen fuel cells

Item	Unit	Small	Large	Comment
Technical parameters				
Ramp up rate		0-100% in < 1min	0-100% in < 1min	
Ramp down rate		100-0% in < 1min	100-0% in < 1min	
Start-up time	Min	Warm: < 1min	Warm: <1min	
Min stable generation	% of installed capacity	25%	25%	Per Ballard datasheet for 200kW unit
Project timeline				
Time for development	Years	1-2	1-2	
First year assumed commercially viable for construction	Year	2025	2025	
EPC programme	Years	~2	~2	
– Total lead time	Years	1-2	1-2	Highly variable depending on supply/demand
– Construction time	Weeks	20	26	
Economic life (Design life)	Years	20	20	Assuming stack replacement takes place after approx. 10yr
Technical life (Operational life)	Years	20	20	

[200] **FCmove-MD-Specification-Sheet.pdf**

4.5.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined hydrogen fuel cells.

Table 4.8 Development cost estimates – Hydrogen fuel cells

Item	Unit	Small	Large	Comment
CAPEX – EPC cost				
Relative cost	$/kW (Gross)	7,000	6,000	Including allowance for BoP, lower economies of scale for smaller unit
Total EPC cost	$	315,000	7,200,000	
– Equipment cost	$	142,000	3,240,000	Industry typical 45% for packaged plant
– Construction cost	$	173,000	3,960,000	
Other costs				
Cost of land and development	$	16,000	360,000	Consistent with electrolysers, allow 5% of CAPEX
Fuel connection costs	$	-	-	

4.5.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined hydrogen fuel cells.

Table 4.9 O&M cost estimates – Hydrogen fuel cells

Item	Unit	Small	Large	Comment
Fixed O&M cost	$/MW/year (Net)	350,000	300,000	Based on 5% of CAPEX p.a.
Variable O&M cost	$/MWh (Net)	Included above	Included above	
Total annual O&M cost	$	15,750	360,000	Excluding stack replacement

4.5.7 Retirement cost estimates

Retirement costs for the defined hydrogen fuel cells are outlined in the table below.

Table 4.10 Retirement cost estimates – Hydrogen fuel cells

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$/MW (Gross)	600,000	
Disposal costs	$/MW (Gross)	5,000	
Recycling costs	$/MW (Gross)	(103,000)	15% of estimated stack material value[201]
Total retirement costs	$/MW (Gross)	502,000	

[201] **Electrolyzer and Fuel Cell Recycling for a Circular Hydrogen Economy**

4.6 Steam Methane Reforming with and without Carbon Capture and Sequestration

4.6.1 Overview

Steam methane reforming involves reacting methane (predominantly as natural gas) with steam at high temperature (typically around 850-1000°C) and moderate pressures (15-30 barg). in the presence of nickel catalyst to produce hydrogen and carbon monoxide. The reactor is a furnace with tubes filled with catalyst where the reforming reactions take place. The reforming reactions are endothermic and energy is supplied through combustion of natural gas and/or fuel gas generated on site in the radiant section of the reactor. A steam: carbon ratio of around 2.5-3.0 mol/mol is typically maintained to prevent catalyst deactivation which would increase operational costs.

Following the reformer, the reactor product is typically subjected to a water-gas shift reactor to maximise hydrogen production from the feed and then purified through a pressure swing adsorption unit to produce relatively pure hydrogen. The tailgas (reject gas) from the pressure swing adsorption unit is typically routed to the reformer as fuel gas and supplemented with natural gas.

The flue gas from the radiant section of the reformer is a mixture of steam, carbon dioxide, nitrogen and excess oxygen.

The carbon intensity of grey hydrogen, that is steam methane reforming and hydrogen production without capture of the flue gas from the radiant section of the reformer is in the order of 8.0-10.5 kg CO_2/kg H_2.

Capturing CO_2 in the flue gas reduces the carbon intensity to around 0.8-4.4 kg CO_2/kg H_2[202]. This is commonly known as “blue hydrogen”. Post-combustion capture is utilised to capture CO_2 from the flue gas, before compression, conditioning, transport and sequestering (either chemically or more commonly geologically). The flue gas has a relatively low concentration of CO_2 (3-15%) which makes it challenging to separate CO_2 efficiently from the other gases in the flue gas. The most common separation technology is solvent absorption (amine-based solvents mainly)[203], while other technologies are available but typically more expensive or energy intensive[204].

4.6.2 Current trends

Steam methane reforming remains the dominant production pathway for hydrogen production, accounting for approximately 95% of global hydrogen supply. In 2024, the market value for steam methane reforming hydrogen generation was US$146.4 B, and it is expected to grow to US$284.0 B by 2034[205]. However, the carbon intensity of steam methane reforming without carbon capture (“grey” hydrogen) is challenging.

Blue hydrogen may offer a path to scale at an affordable price, compared to green hydrogen, which requires significant increases in scale of current generation and transmission equipment, major reduction in the electrolyser and hydrogen storage equipment cost and in particularly, the availability of relatively cheap and firm renewable power. To reduce the carbon intensity of this pathway, there is a growing emphasis on integrating CCS with SMR to capture up to 95% of CO_2 emissions.

[202] **Green-vs-Blue-Hydrogen-report.pdf.** Accessed 29/09/2025.
[203] Liu, H., Idem, R. and Tontiwachwuthikul, P. (2019). Post-combustion CO2 Capture Technology by using the amine based solvents. Springer.
[204] Madejski, P. et. Al. (2022). Methods and Techniques for CO2 Capture: Review of Potential Solutions and Applications in Modern Energy Technologies. Energies, 15(3).
[205] **Steam Methane Reforming Hydrogen Generation Market Report - 2034.** Accessed 29/09/2025.

Table 4.11 SMR and CCS pilot/demonstration projects

Project	Country	Description	Scale	Key years (construction / trial / operation)
Quest CCS (Scotford Upgrader)[206]	Canada (Alberta)	H2 production from SMR, carbon capture and storage in saline aquifer 64 km from production site	Up to 1.2 Mt/annum CO_2 capture	Construction ~2012–2015; capture began Nov 6, 2015
Air Products — Port Arthur CO_2 capture demonstration / retrofit[207]	USA (Texas)	Large-scale retrofit carbon capture from 2 industrial SMR trains	Captured ~1 Mt/annum CO_2	DOE demonstration period from December 2012 to September 2017
Tomakomai Project - Japan[208]	Japan	Captured carbon from hydrogen production unit offgas with 50% CO2 for storage in offshore saline aquifers	0.1Mt/annum of CO_2, up to 0.3 Mt/annum in final stages	2016-2019

For blue hydrogen to be accepted widely CCS must be available. The Global CCS Institute (a not-for-profit think tank with a mission to accelerate the deployment of CCS as an integral part of the net-zero emissions future through advocacy and knowledge sharing) released its Global Status of CCS 2024[209], noting that the number of CCS facilities in operation rose to 50 in 2024, with 44 more in construction and 247 projects in advanced development. Three of the operating facilities globally are part of the power generation and heat industry, while two are in the bioenergy/ethanol sector.

Australia has a very large potential for geological storage of CO_2, with the CO_2 Storage Resource Catalogue estimating that Australia has 31 GT of sub-commercial and 470 Gt of undiscovered storage resource available[210]. There are two CCS projects in commercial operation in Australia, notably:

– The Gorgon CCS project, storing CO2 captured from the Gorgon gas project in deep saline aquifers beneath Barrow Island off the Western Australian coast, with a capacity to store up to 4 Mtpa of CO2 (currently the largest operating CCS project in the world), and
– The Santos Moomba CCS project, with an injection capacity of up to 1.7 Mtpa CO2 captured from the Moomba gas processing plant before being transported by underground pipeline and injected into depleted oil and gas reservoirs in the Cooper Basin.

The costs associated with CCS remains challenging, with more development required to reduce the cost of carbon capture, particularly from dilute (post-combustion) streams as well as the cost of sequestration. A study conducted in 2021 determined that to achieve capture rates above 85% from SMR flue gas (and other post-combustion sources), most estimates were above US$80/t CO_2[211]. However, Santos claims that the Moomba CCS project has a lifecycle cost of less than US$30/t CO_2[212], indicating that capture costs are decreasing with practical experience and in the right circumstances.

Regulatory frameworks are different for each State, with WA, SA and Victoria having specific legislation governing CCS projects. Queensland has introduced a legislative ban on all CO_2 storage and injection activities in the Great Artesian Basin areas of the State.

Other notable emerging hydrogen production technologies utilising natural gas reforming to achieve lower carbon emissions per kg of hydrogen produced include:

– Sorption-Enhanced SMR (SE-SMR) is another option which combines traditional SMR with in-situ CO_2 Capture using solid sorbents[213]. SE-SMR is not commercially available and currently at a TRL of approximately 4. It also adds processing complexity to the SMR due to a solids processing step being

206 **Carbon Capture and Sequestration Technologies @ MIT**
207 Air Products and Chemicals Inc. Demonstration of Carbon Capture and Sequestration of Steam Methane Reforming Process Gas Used for Large-Scale Hydrogen Production. Final Report. March 2018.
208 **Tomakomai CCS Demonstration Project – CCUS around the world in 2021 – Analysis - IEA**
209 **Global Status Report 2024 - Global CCS Institute.** Accessed 29/09/2025.
210 **Understanding CCS in Australia | Australia | Global law firm | Norton Rose Fulbright**
211 **Costs-of-Blue-Hydrogen-Production-Too-High-Without-Fiscal-Life-Support_February-2022.pdf.**
212 **Santos Moomba Carbon Capture and Storage | Santos**
213 **Advancements in sorption-enhanced steam reforming for clean hydrogen production: A comprehensive review - ScienceDirect**

introduced whereby a sorbent is injected directly to the SMR and then routed to a second reactor for regeneration.

– Another alternate process configuration involves e-SMR (electrical SMR), where process heat is supplied through power to the SMR. For the carbon footprint to be low, electrical heat supplied to the SMR has to be from renewable electricity. The transfer of thermal energy in electrified reactors can be achieved in various ways, such as microwave-assisted heating, induction heating or resistive heating[214]. E-SMR is typically small scale and still emerging. Topsoe has developed an e-SMR technology and was planning on demonstrating the technology at a green methanol facility[215]. It is unclear if the unit was constructed and commissioned from publicly available information. A pilot facility was constructed and run at the Aarhus University in Denmark, also based on Topsoe's eREACT technology. This unit was operated although no clear information is available on how much hydrogen was produced[216].

4.6.2.1 Summary of changes

The following changes have been identified from the 2024 report:

– A low and high case of 100 and 800 tpd was selected, compared to 200 and 900 tpd for the 2024 report. This was due to availability of vendor data at the selected capacities.
– For the "high" case, an option with CCS included in this Report.
– The CAPEX for the low case excluding CCS is ~152% of the 2024 report value for the low case without CCS, and 142% of the 2024 report value for the low case with CCS. The values included here are based on vendor information for an Australian-based project.
– The CAPEX for the high case including CCS is 55% of the 2024 report value. The CAPEX included here is based on vendor information for an Australian-based project.
– It is not clear if the OPEX value included reported in the 2024 report is based on inclusion or exclusion of CCS and therefore, the values cannot be compared, but in general, the OPEX costs are considerably higher as calculated for this Report compared to the 2024 report. Again, the OPEX values included here are based on Australian-based projects completed by GHD.

4.6.3 Selected hypothetical facility and cost estimate

For the low case, only carbon capture from the PSA off-gas stream is included, whereas carbon capture from all integrated streams is included for the high case, achieving very low residual carbon emissions per kg of hydrogen. For the high case, carbon is captured from the shifted syngas prior to the PSA unit and/or from the furnace flue gas, achieving 90+% carbon capture.

Table 4.12 SMR plant criteria

Item	Low	High	Comment
Hydrogen production rate	100,000 kg/day	800,000 kg/day	Based on typical reforming technology capacities
CO_2 production rate	10 kg CO_2/kg H_2	10 kg CO_2/kg H_2	Typical carbon intensity for SMR/WGS/PSA for hydrogen production
CO_2 emission rate after CCS	4.8 kg[217] CO_2/kg H_2	0.9 kg[218] CO_2/kg H_2	Only PSA off-gas carbon capture for low case, includes carbon capture from all streams for high case
Water required	6.3 kg H_2O/kg H_2	6.3 kg H_2O/kg H_2	Typical

[214] **Electrified steam methane reforming as efficient pathway for sustainable hydrogen production and industrial decarbonization: A critical review - ScienceDirect**
[215] **Topsoe to build demonstration plant to produce cost-competitive CO2-neutral methanol from biogas and green electricity**
[216] **Electrified steam methane reforming of biogas for sustainable syngas manufacturing and next-generation of plant design: A pilot plant study - ScienceDirect**
[217] Pellegrini, L.A., De Guido, G and Moioli. (2020). Design of the CO2 removal Section for PSA Tail Gas Treatment in a Hydrogen Production Plant. Front. Energy Res. 8:77.
[218] GHD project information

Table 4.13 SMR plant cost estimate – excluding and including CCS

Item	Low	High	Comment
Hydrogen production rate	100 tpd	800 tpd	
Cost of production	\$3.0-5.7/kg H_2 (without CCS) \$5.5-8.0/kg H_2 (with CCS)	\$2.0-3.6/kg H_2 (without CCS) \$3.0-4.5/kg H_2 (with CCS)	Typical range from GHD projects
CAPEX	\$2,216/kW	\$1,106/kW	Excluding carbon capture, based on LHV
CAPEX	\$2,882/kW	\$1,372/kW	Including carbon capture, based on LHV
Total CAPEX cost	\$308 M	\$1,229 M	Excluding carbon capture, based on LHV
Total CAPEX cost	\$400 M	\$1,525 M	Including carbon capture, based on LHV
OPEX / year	\$30.8 M	\$84.9 M	Excluding carbon capture, based on LHV. Excludes NG cost.
OPEX / year	\$41.4 M	\$157.9 M	Including carbon capture, based on LHV. Excludes NG cost.

4.7 Hydrogen storage

4.7.1 Overview

Hydrogen is a challenging substance to store. This is due to the nature of hydrogen; it has very low volumetric density and consists of small molecules with high diffusivity leading to leaks and seal wear. In addition, it has high compression energy requirement, high liquefaction energy penalty and it also embrittles steels and some alloys, limiting usable materials for infrastructure such as pipes, tanks and compressors. Storage of hydrogen in pipelines is outlined in Section 4.7.4.

There are various options for hydrogen storage, each with their own advantages and disadvantages. These are listed in the table below.

Table 4.14 Hydrogen storage methods

Storage Method	Typical Conditions (°C, bar)	Density (kg H_2/m^3)	Energy Penalty for Storage[219]	Tank / Carrier Type	Key Challenges
Compressed Gas @ 200 bar (range 100-300 bar)	Ambient, 200 bar	~16[220]	~4–5% LHV for compression	Steel cylinders – MCPs and large vessels. Mobile storage – tube trailers.	Bulky tanks, moderate compression energy
Compressed Gas @ 350 bar (range 350-500 bar)	Ambient, 350 bar	~23	~6–8% LHV for compression	Composite Type III/IV cylinders. Cascade storage for refuelling. Mobile storage – tube trailers.	Heavier tanks, still low density, moderate compression energy
Compressed Gas @ 700 bar	Ambient, 700 bar	~40	~10–15% LHV for compression	Advanced carbon-fibre composites. Cascade storage for refuelling.	Expensive tanks, embrittlement, leakage, high compression energy
Cryogenic Liquid H_2 (LH_2)	–253 °C, 1 bar	~71[221]	~30–40% LHV for liquefaction	Double-walled, vacuum insulated tanks	Boil-off losses, insulation cost, safety

[219] Energy penalty = % of hydrogen LHV consumed for compression, liquefaction or chemical conversion
[220] For comparison, methane (NG) density at 20°C and 1 bara is 0.659 kg/m^3, compared to 0.0827 kg/m^3 for hydrogen at the same conditions.
[221] For comparison, liquefied natural gas (LNG) has a density of 410-500 kg/m^3

Storage Method	Typical Conditions (°C, bar)	Density (kg H_2/m³)	Energy Penalty for Storage[219]	Tank / Carrier Type	Key Challenges
Cryo-Compressed H_2 (CcH_2)	–253 °C + up to 250–350 bar	50–70 (depending on P/T)	~25–35% LHV	Cryogenic, pressurised composite tanks	Complex design, expensive, still cryogenic
LOHC (e.g. toluene/methylcyclohexane)	Ambient T, ambient P	~50–60 (H_2 equivalent)	Hydrogenation /dehydrogenation consumes 30–40% LHV	Standard liquid fuel tanks	High energy penalty, slow reaction kinetics resulting in large reactors and recycles, increasing capital investment

Storing gaseous hydrogen requires compression, which adds CAPEX (for the muti-stage compressors) and OPEX (power consumption). It is the simplest form of hydrogen to store, requiring little action to be able to use the hydrogen. At higher pressures, gaseous hydrogen is denser, and therefore a higher mass of hydrogen can be stored in the same volume. However, as the maximum storage pressure increases, the wall thickness of vessels increase, making them more expensive. At very high pressures (500 barg+), carbon composites may be preferred for vessels, particularly where mobile applications make steel vessels with very thick shells heavy and therefore unpractical, so that vessel costs are significantly higher.

To store hydrogen as a liquid requires compression and cooling to -253°C, which consumes considerable energy. Liquid hydrogen is denser than compressed hydrogen gas and therefore has a much smaller footprint, but it requires to be stored in insulated vessels and typically has high boil-off losses, which have to be reliquefied, further adding to the high energy demand.

Hydrogen could be incorporated into carriers that can be more readily transported as liquids, such as ammonia and liquid organic hydrogen carriers (LOHCs). These liquids are much easier to transport than hydrogen, particularly LOHCs which are liquids at ambient conditions, and tend to already have infrastructure for storage and transport available. LOHCs are more energy dense than gaseous hydrogen but not as dense and liquid hydrogen. In addition, liquid hydrogen only has to be vaporised for use at the offtaker whereas LOHCs have to be dehydrated and separated to produce the original chemical and hydrogen gas. This entails extra energy and cost, which must be balanced against the lower transport costs. The best known LOHC is methylcyclohexane (MCH) which is classed as “very toxic to aquatic life with long lasting effects”, and research is ongoing into chemicals that can be used to the same effect but may be less harmful to the environment.

4.7.2 Recent trends

4.7.2.1 Gaseous compressed storage

Gaseous hydrogen storage (particularly at low pressures such as 60-100 barg) is mature and commercially available. It is a simple storage method and has a lower required energy input compared to liquefaction, with only compression required. However, because of the low volumetric density of gaseous hydrogen storage, even at high pressures (for example at 700 bar, the density of gaseous hydrogen is only 42 kg/m^3), this form of hydrogen storage is expensive due to the large high pressure vessels required.

There are safety concerns as leaks and embrittlement of the vessel and piping materials can occur relatively easily. Hydrogen has a very wide flammability range in air (4-75%), the minimum ignition energy is extremely low so that small static discharges could ignite hydrogen and it has a high flame speed that could produce violent pressure rise under the right conditions (rapid deflagration). Therefore, storage of large volumes of high pressure gaseous hydrogen carries a risk.

For small scale storage, such as for hydrogen refuelling stations or micro-turbine or fuel cell use, gaseous hydrogen can be stored in manifolded cylinder packs (MCPs), cascade storage (multiple cylinders at different pressures) or tube trailers. Cascade storage configurations and top up using a compressor are employed to minimise the energy of compression by utilising lower pressure gas for part of the filling process with the intent to use the lowest suitable pressure at each stage of the fill.

Larger scale gaseous hydrogen storage can be accomplished in steel pressure vessels. Iberdrola (Idesa) have built pressure vessels for larger volume gaseous hydrogen storage. The Puertollano green[222] hydrogen plant in Spain includes some of these larger vessels; the tanks can each store 2,700 kg of hydrogen at a maximum of 60 bar, with dimensions of 23m high and 2.8 m in diameter[223]. It stands to reason that higher volume hydrogen storage vessels are possible; the limitation will typically be the weight of the vessels due to the high wall thicknesses required and the maximum vessel dimensions that can be transported to a site (typically, vessels would be manufactured and completed before being transported to the operating site).

Storage of gaseous hydrogen in pipelines is also possible; this is addressed in Section 4.7.4.

A form of gaseous hydrogen storage that has been developed is hydrogen floating storage by Australia's Provaris Energy. The unit (H2Leo) developed to date has a design capacity range of 300-600 tonnes of hydrogen at a maximum pressure of 250 barg[224] and could be expanded up to 2,000 tonnes[225]. The company is currently investigating building the first smaller units, H2Neo units[226]. The company claims that the cost of gaseous hydrogen storage would be in the order of $0.2-0.3 M per tonne[227], compared to the current large scale static storage capital cost of $1-2 M per tonne.

4.7.2.2 Hydrogen liquefaction and Liquefied Hydrogen (LH_2) storage

One method that is being explored to reduce the challenges associated with large scale hydrogen storage, these being (1) large volumes of storage due to low volumetric density of gaseous hydrogen even at high pressures, and (2) high associated CAPEX, is the storage of hydrogen as a cryogenic liquid. Liquefied hydrogen has a much higher density than gaseous hydrogen. However, 30-40% of the energy content of hydrogen stored is consumed in liquid cooling, with up to 10-11 kWh/kg H2 energy required. This can be compared to the energy required for NG liquefaction, at approximately 0.25 – 0.35 kWh/kg LNG[228], or 1.8 – 2.5% of LNG LHV. Most liquefaction units are also still small-scale, with the largest facility globally being the Incheon Liquefied Hydrogen Plant in South Korea, with an estimated capacity of 90 tonnes/day (30,000 tonnes per annum)[229]. Hydrogen liquefaction would have to undergo significant improvements in CAPEX and power efficiency to make it competitive with other storage methods. At present, it is estimated that liquefaction would add $2.00/kg H2 of more to the levelised cost of hydrogen production. With the implementation of refrigerant cycles and better precooling, better heat exchanger and insulation improvements, better heat integration and boil-off management and ortho-para optimisation, it is expected that the energy requirement may be reduced to 8-9 kWh/kg H_2 within a few years[230].

Liquid hydrogen storage is typically accomplished in vacuum insulated double walled steel storage tanks, ranging from around 800 to 4,800 kg (weight of hydrogen stored). CB&I constructed an LH_2 sphere in 2022 at the Kennedy Space Center for 5,000 m^3 of LH_2[231], and also has a conceptual design for a new double wall vacuum insulated LH_2 sphere which could hold up to 40,000 m^3 of LH_2[232].

The Suiso Frontier, the world's first liquefied hydrogen carrier ship was constructed by Kawasaki Heavy Industries to demonstrate a pilot international LH_2 supply chain, carrying liquefied hydrogen from Australia to Japan and back[233].

[222] Where "green" hydrogen refers to hydrogen produced from water electrolysis and renewable power, typically with a carbon intensity of less than 1.0 kg CO2/kg H2, although definitions vary depending on the jurisdiction.
[223] **The first 5 Green Hydrogen storage tanks arrive in Puertollano - Iberdrola**
[224] **Provaris Energy, Norwegian Hydrogen and Uniper have made progress | Provaris Energy**
[225] **Provaris showcases compressed hydrogen floating storage concept | Provaris Energy**
[226] **Provaris Energy moves ahead with compressed H2 carrier plans | World Ports Organization**
[227] **02655724.pdf**
[228] Edited by Mokhatab, M et. Al. (2014). Handbook of Liquefied Natural Gas. Gulf Professional Publishing.
[229] **SK E&S builds world's largest liquefied hydrogen plant - The Korea Times**
[230] **Liquid H2 Workshop-Air Liquide.pdf**
[231] **cbi-liquid-hydrogen-brochure-2022-digital.pdf**
[232] **McDermott's CB&I Storage Solutions Completes Conceptual Design for World's Largest Liquid Hydrogen Sphere**
[233] **The Suiso Frontier - HESC**

4.7.2.3 Emerging hydrogen storage methods

Emerging hydrogen storage methodologies that are under development include:

– Solid state storage such as metal hydrides, where hydrogen is chemically bound to a metal hydride at low pressure. These include MgH_2, $NaAlH_4$, $LiAlH_4$, LiH, $LaNi_5H_6$ and $TiFeH_2$ as examples. These materials can absorb and release hydrogen under certain conditions, making them suitable for various applications, including stationary, marine, and transport sectors. The vessels can be kept at ambient temperature and pressure with lower safety concern than for compressed hydrogen storage vessels and for liquid hydrogen storage systems. Hydrides store only 2-6% hydrogen by weight but have high volumetric storage densities[234].

  Metal hydride systems can be cost-effective for hydrogen storage, depending on the type of metal hydride utilised and its associated cost. Depending on the raw material price, the production costs can vary. Other than the cost of the storage material itself, the overall cost is influenced by factors such as hydrogen uptake rates, operational cycles and the energy required to release hydrogen from the metal hydride. The long filling and extraction times due to slow kinetics is a significant disadvantage for this type of storage. Their economic viability depends on continued advancements in material science and system design. Extending charging times and increasing operating cycles could significantly reduce the levelised cost of storage.

  To recover the hydrogen from the metal hydride, heat must be added to break the bonds between the hydrogen and the metal. Typically, the heat required to release hydrogen make this type of storage uneconomical at present. The last 10% of hydrogen dissolved in the metal matrix is difficult to remove and represents strongly bonded hydrogen that cannot be recovered in the normal charge/discharge cycle.

  Metal hydride systems require a much smaller footprint than compressed hydrogen gas storage, but these vessels have considerable weight, making them less attractive for mobile storage. For example, for a passenger car, the storage to vehicle weight ratio is approximately 30% if a metal hydride system is used to store 6 kg of hydrogen. This is reduced but still substantial for a heavy-duty truck at a ratio of 7.5% to store 30 kg of hydrogen[235]. For railroad and road-bound applications, fast refilling times are required, which is typically not possible for metal hydride systems without careful heat dissipation management.

– Cryo-compressed storage (CcH_2), which combine the benefits of the high energy density of LH_2 and mass retention of GH_2. Hydrogen is stored at cryogenic temperatures but also under moderate pressure to produce hydrogen in a dense cryogenic state. Compressing liquefied hydrogen at 20 K increases volumetric storage density from 70 g/L at 1 bar to 87 g/L at 240 bar. Because the tank is pressurised, hydrogen boil-off can be absorbed as pressures increase, leading to less frequent venting or avoiding venting altogether for reduced losses. The technology for handling CcH_2 is still under development. Issues remain with LH_2 pump performance, vacuum stability and manufacturability of the equipment required[236]. High cost, complexity and infrastructure gaps have restricted adoption.

– Liquid organic hydrogen carriers (LOHC). These compounds can reversibly absorb and release hydrogen through chemical reactions, offering a promising solution for hydrogen storage and transport, typically at ambient conditions, particularly for large-scale applications. There are various LOHCs that have been identified, each with their own properties and potential applications, such as toluene, methylcyclohexane, n-ethylcarbazole and dibenzyltoluene. Research is focused on both monocyclic and heterocyclic organic compounds for efficient hydrogen storage and dehydrogenation. Utilising LOHCs would enable large scale hydrogen storage without logistical and safety complexities of compressed hydrogen gas storage or cryogenics. Due to the added complexity of having to dehydrogenate at the user end, low technology readiness levels of these systems at present and environmental concerns with so many of the proposed liquids, LOHCs have not been adopted commercially yet.

[234] **Costs of Storing and Transporting Hydrogen.**
[235] **A review on metal hydride materials for hydrogen storage - ScienceDirect**
[236] ILK Dresden, Home page, accessed August 2022 from **https://www.ilkdresden.de/leistungen/forschung-und-entwicklung/projekt/wasserstoff-und-methan-versuchsfeld-am-ilk**

4.7.2.4 Summary of changes

The material changes from the 2024 report include:

– Compressed gaseous hydrogen storage was added. For gaseous storage (GH2), smaller storage volumes are practical and accordingly 20 tonnes of storage was selected for the gaseous storage case. This represents 75% of daily hydrogen production from the selected SMR. Given that hydrogen production from a NG reformer is continuous, the storage capacity could be reduced as it would be a buffer to supply downstream units when the reformer is off-line but the main goal is to demonstrate the differences between gaseous and liquid hydrogen storage.
– Storage for the LH2 case was increased from 270 tonnes to 355 tonnes, reflecting the largest vessel currently available (5,000 m3).
– On a per ton basis, the CAPEX for hydrogen liquefaction and storage is A$0.53 M/t in this Report, compared to A$0.75 M/t in the 2024 report. The costs included in this Report are based on vendor information for a hydrogen liquefaction plant of similar capacity and published costs for LH2 storage.
– Pipeline costs included in this Report reflects a hydrogen pipeline for transmission and storage, rather than hydrogen distribution network at low pressure which was included in the 2024 report.

4.7.3 Selected hypothetical project and cost estimate

Both liquid and gaseous hydrogen storage cases are addressed. Hydrogen is assumed to be produced from an SMR facility, so that hydrogen is produced at a typical 6 barg following PSA.

Table 4.15 Technical parameters – Gaseous and Liquid hydrogen storage

Item	Unit	Value (GH2)	Value (LH2)	Comment
Hydrogen production rate	kg H_2/day	27,000	27,000	
Electricity usage	kWh/kg H_2	4.0-5.0	11.0	Only for storage preparation, compression from 6 to 60[237] barg for GH_2, liquefaction for LH_2 included
Storage requirement	Tonnes	20.0	355[238]	

For 20 tonnes of gaseous hydrogen storage, the following is required:

– 2x50% (of total hydrogen flow rate allowed to storage per hour) hydrogen compressors, or 2x2 t/h at a CAPEX of $3.7 M per unit[239]
– GH_2 storage, with an associated CAPEX of $1,750/kg H_2[240]

For 355 tonnes of liquid hydrogen storage, the following is required:

– 7,000 tpa liquefaction plant at a CAPEX of $101 M (2020 value), and updated to $138.0 M by CEPCI to 2024[241]
– LH_2 storage, with an associated CAPEX of US$105/kg H_2 [242], or A$150/kg H_2

Table 4.16 Cost estimates – Gaseous and Liquid hydrogen storage

Item	Unit	Value (GH2)	Value (LH2)	Comment
CAPEX	$ M	35.0	188.3	GH2 = compressors and storage, LH2 = liquefaction and storage
OPEX /Year	$ M	1.1	22.0	Excluding power cost, assume OPEX is 3% of CAPEX per annum for GH_2 and 11.5% per annum for LH_2

[237] Typical production pressure for hydrogen following pressure swing adsorption unit for purification
[238] Largest LH2 vessels constructed to date (5,000 m3)
[239] GHD project cost
[240] GHD project cost
[241] GHD project cost
[242] Burke, A. et. Al. (2024). Hydrogen Storage and Transport: Technologies and Costs. UC Davis Institute of Transportation Studies.

4.7.4 Hydrogen pipelines and associated costs

Hydrogen pipelines for storage would typically be buried. Hydrogen pipelines are similar to natural gas (NG) pipelines with some broad differences:

– Engineering costs are projected to be in the order of 20% higher than for NG pipelines due to the effort of engineering and specifying the pipe steel to withstand those failure modes that are aggravated by hydrogen. Engineering costs are typically approximately 2% of the total pipeline cost.
– Line pipe steel cost is typically 20% higher than NG line pipe steel. Typically, steel costs are approximately 30% of the total pipeline cost.
– Due to pipe bending that is required to be controlled in hydrogen pipelines, alternative routing and other changes are required compared to NG pipelines, expected to increase the total pipeline cost by approximately 10%.
– Pipeline construction costs are higher for hydrogen pipelines, with the construction costs expected to increase by 20%.
– Combining these costs results in an increase in average cost per inch per kilometre of approximately 25% over those for a NG pipeline. The resultant pipeline cost is $93,750/inch/km[243].

If a pipeline network is developed for hydrogen transmission and distribution, a considerable volume of hydrogen would automatically be stored in such a network. Existing NG pipelines could also be utilised for hydrogen transmission and distribution. It is generally understood that up to 20vol%[244,245] hydrogen could be absorbed in a NG system not designed for hydrogen-specific service.

If a portion of pipeline is specifically used for storage, the pressure in the pipeline must be maintained within specific limits to maintain the integrity of the pipeline materials, for example a pressure differential of 3-10 bar would be acceptable for medium-sized pipelines and pipeline distances, while 5-20 bar on a daily basis is likely acceptable for long distance transmission pipelines, but higher pressure differentials could lead to cyclic stress due to large pressure swings, accelerating fatigue, cracking and hydrogen embrittlement.

Only carbon steel pipelines are considered; HDPE is sometimes considered for hydrogen distribution pipelines, but not for transmission (low pressure systems only)[246].

Table 4.17 Indicative cost for a new hydrogen pipeline

Item	Unit	Value	Comment
Pipeline diameter	DN, inches	DN500[247], 20 inch pipeline	Typical pipeline diameter
Gas velocity	m/s	10	Typical for hydrogen
Maximum Operating Allowable Pressure (MOAP)	barg	100	Assumed
Operating pressure	barg	72	Typical to operate hydrogen pipeline at 72% of MOAP
H2 density at assumed conditions	kg/m^3	5.7	72 barg and 30°C
Hydrogen per km of pipeline (typical)	kg H_2/km	1,043	Volume of hydrogen in pipeline at assumed conditions
Hydrogen per km of pipeline (storage potential)	kg H_2/km	215	Assuming a maximum of 20 bar pressure drop in linepack
Pipeline cost	$/inch/km	93,750	

243 Based on GHD pipeline project cost.
244 **Hydrogen Integration into Natural Gas Pipelines: Risk Analysis and Regulatory Recommendations - ScienceDirect**
245 **EPRI_Safety_of_Hydrogen_Pipeline_Blending_2019_3002017253.pdf (SECURED)**
246 **IGEM/TD/21 - Reference Standard for Hydrogen distribution for new steel and PE mains and services | The Institution of Gas Engineers and Managers (IGEM)**
247 DN500 pipeline has an outer diameter of 508mm, assuming a wall thickness of 12.7mm (schedule 40 pipe), the inner diameter of the pipeline is 482.6mm.

4.8 Geological hydrogen storage

4.8.1 Overview

Underground hydrogen storage offers several advantages over traditional vessel storage for hydrogen, including lower investment costs, increased safety and reduced surface footprint. Underground hydrogen storage generally falls into one of two main categories, these being:

1. Porous geological formations, including depleted hydrocarbon reservoirs and deep saline aquifers and
2. Artificially solution-mined cavities within salt formations or salt caverns.

Geological storage of natural gas is well understood and known; hydrogen storage in geological structures has been conducted at pilot or demonstration scale but not yet at commercial scale.

Constructed caverns have been used for storage of bulk fluids since the early 1940's during World War II[248]. There are two types of constructed caverns in common use, these being salt caverns developed by solution mining cavities in salt deposits and hard rock mined caverns constructed in competent rock using conventional mining techniques.

Salt caverns are more common in North America due to the presence of suitable salt deposits and the lower cost of construction compared to hard rock mined caverns. However, in locations that do not have adequate salt resources, hard rocked mined caverns can be an economic alternative to surface storage.

The types of geological storage that could be employed for hydrogen include the following:

– Salt caverns
– Hard rock mined caverns
– Lined rock caverns
– Depleted reservoir storage
– Aquifer storage

Each of these types of storage have some specific limitations, siting requirements and operational requirements that impact levelized cost of storage such as a percentage of cushion gas required for operations. Above ground treatment is required when hydrogen is extracted from a cavern prior to use. These treatments include dehydration and other contaminant removal and compression processes.

4.8.2 Recent trends

The development of underground hydrogen storage will be important to provide a cheaper means of large-scale gaseous hydrogen storage in the event of supply disruptions. Salt caverns are already used for industrial storage in the US and the UK. There are several projects ongoing for the demonstration of fast cycling in salt caverns for hydrogen storage and the repurposing of caverns previously used to store natural gas.

The Clemens salt dome project in Texas, US has been storing hydrogen since 1983 and remains in operation at a long-term hydrogen storage facility, primarily for industrial feedstock. ConocoPhillips operates this site using three salt chambers to store high-purity hydrogen, utilising brine as a buffer gas to maintain pressure and displace the stored hydrogen[249].

Storengy's SaltHy in Germany is expected to reach commercial scale in 2030. Storengy and its partners developed the first demonstrator of large-scale green hydrogen storage, called HyPSTER, using a salt cavern in Etrez, France to store up to 44 tonnes of hydrogen. Cycling tests were completed successfully [250].

In Australia, depleted gas reservoirs (Otway Basin[251]) are being investigated for hydrogen storage, with commercial operation possible by 2030 if pilot tests succeed. The Lochard Energy H2RESTORE project in the

[248] Bays, C. (1963). Use of Salt Solution Cavities for Underground Storage, Northern Ohio Geological Society
[249] **Underground hydrogen storage suitability index: A geological tool for evaluating and ranking storage sites - ScienceDirect**
[250] **HyPSTER: the successful completion of cycling tests - Storengy**
[251] **78-GET24-Hydrogen_Transitioning-from-underground-gas-storage-to-underground-hydrogen-storage-in-the-onshore-Otway-Basin-Australia.pdf**

Otway Basin received funding from ARENA in 2024 for an 18 month feasibility study into large-scale hydrogen production and storage.

Several projects around the world to develop underground hydrogen storage are highlighted in the table below.

Table 4.18 Select proposed underground hydrogen storage projects around the world

Project / Region	Storage Type	Projected Capacity (H_2)	Timeline	Status (2025)	TRL / Readiness
Storengy "SaltHy" (Stade, Germany)	Salt caverns	~15,000 t H_2 (2 caverns, ~7,500 t each)	1st cavern ~2030	Design & permitting	TRL 6–7 (demo proven, scale-up ongoing)
Etzel H2CAST (Germany/Netherlands)	Salt cavern	Pilot: ~90 t H_2 → Expansion option to thousands of tonnes	Pilot injection 2025 → expansion by 2028	Demonstrator being filled now	TRL 7–8
SaltHy (Germany, Harsefeld)	Salt cavern	~5,200 t H_2	~2028–2030	Design & site preparation	TRL 5–6
HyNet North West (UK)	Salt caverns (reuse)	Conceptual: 2,000–6,000 t H_2 (several caverns)	2028–2030	Linked to UK hydrogen backbone project	TRL 5–6
HYBRIT (Luleå, Sweden)	Rock cavern, lined	Pilot: 100 m³ (~20–30 MWh equiv.) → Commercial design up to ~100 GWh (~4,000–5,000 t H_2)	~2030	Pilot proven 2022–2024	TRL 7
Lochard Energy "H2Restore" (Australia, Otway Basin)	Depleted gas reservoir	TBD, estimated thousands of tonnes seasonal storage	Feasibility → pilot 2026–27 → commercial ~2030	Pre-FEED studies in 2025	TRL 4–5
HyStock (Netherlands, near Groningen)	Salt cavern	Planned ~5,000–10,000 t H_2	2029–2030	Early-stage project under Gasunie	TRL 5
US (Texas / Gulf Coast concept projects)	Salt caverns	Conceptual: up to 100,000 t H_2 (multi-cavern networks)	Post-2030	Several feasibility studies underway	TRL 3–5

4.8.2.1 Summary of changes

No material changes were observed in the technology or costs from the 2024 to 2025 Report.

4.8.3 Selected hypothetical project

Table 4.19 Configuration and performance – Geological storage

Item	Unit	Value	Comment
Configuration			
Cavern volume	m^3	300,000	For NG storage (more typical use at present), salt caverns with 200,000 – 800,000 m^3 may be used. Typical dimensions could be 50-100 m wide by 100-300 m high.
Maximum storage capacity	tonne	2,200	
Mean depth	m	1,000	Salt deposits typically range from 200-1,500m in depth
Working capacity	m^3	210,000	30% cushion gas is required

Item	Unit	Value	Comment
Performance			
Hydrogen purity	vol%	>95	
Gas cycling requirements		10 annual cycles	Typically, a maximum of 12 cycles is possible
Operating pressure	Bar	100	
Operating temperature	°C	30	
Energy consumption	kWh/kg H_2	1.2	Assuming compression from 10 barg (produced from electrolyser) to 100 barg
Project timeline			
Time for development	Months	18-36	Based on projections for commissioning of existing projects
Project execution	Years	5-7	From FID to commissioning
Major turnaround cycle	Years	4-6	Depends on type of compressor selected and maintenance cycle, this assumes a reciprocating compressor

4.8.4 Development cost estimates

The following table provides CAPEX cost estimates for the defined geological storage.

Table 4.20 Development cost estimates – Geological storage

Item	Unit	Value	Comment
Engineering	$	7,000,000 – 10,000,000	
Below ground costs	$	35,000,000 – 61,000,000	Could vary significantly based on depth and number of wells required
Leaching and brine disposal	$	5,000,000 – 11,000,000	
Above ground costs	$	15,000,000 – 37,000,000	

4.8.5 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined geological storage project.

Table 4.21 O&M cost estimates – Geological storage

Item	Unit	Value	Comment
Operations and maintenance cost	$ per year	1,100,000 – 2,200,000	Assuming 2.2% of above and below ground CAPEX

4.8.6 Retirement cost estimates

Retirement costs for the defined geological storage project are outlined in the table below.

The following must be considered for retirement of geological storage:

– Number of wells that must be capped, as well as their depths. For the selected cavern size, 4 wells are assumed, each with a retirement cost of $250,000/well
– Brine disposal, assumed to be 10% of leaching and brine disposal development cost
– Surface facilities to remove including compressors, and gas treatment units, assume 10% of above ground CAPEX
– Monitoring required following retirement. Assumption is that monitoring costs would be $30,000-50,000/annum and that 10 years of monitoring would be required.

Table 4.22 Retirement cost estimates – Geological storage

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$/tonne (Net)	455	
Disposal costs	$/tonne (Net)	2,045	
Recycling costs	$/tonne (Net)	N/A	
Total retirement costs	$/tonne (Net)	2,680	Includes A$180/tonne for monitoring costs

4.9 Ammonia production facility

4.9.1 Overview

Industrial-scale ammonia production began in the early 20th century with the Haber-Bosch process, which synthesizes ammonia by reacting hydrogen and nitrogen over a metallic catalyst under high temperature and pressure:

$$N2 + 3H2 \rightleftharpoons 2NH3 \ (+42 \text{ kJ/mol})$$

This exothermic (heat generating) process typically sources hydrogen from hydrocarbons (e.g., natural gas via Steam Methane Reforming) and nitrogen from air, and as such, ammonia production contributes about 1-2% to global CO_2 emissions. However low or zero carbon versions are now being explored, for existing applications as well as for use (including overseas) as a low carbon or zero carbon fuel. Classifications include ‘blue ammonia’ (reflecting hydrogen feedstock sourced from fossil fuels with carbon capture) and ‘green ammonia’ (reflecting hydrogen derived from electrolysis, powered by renewable energy). Green and blue ammonia are seen as key opportunities to decarbonise sectors such as fertiliser production and maritime transport, and is being considered for power generation, including co-firing in Japanese coal fired power plants.

Around 70% of ammonia is used in fertilizers, with additional applications in explosives and refrigeration. Global production is approximately 180 million tonnes annually, with Australia contributing ~1%, operating seven plants (two in WA, four in QLD, one in NSW), all using natural gas.

Traditional plants range from 250 to 3,000 tonnes/day, with new designs exceeding 5,000 tonnes/day to meet rising global demand and leverage economies of scale.

4.9.2 Recent trends

Conventional ammonia plants have trended toward larger capacities to improve efficiency and reduce specific capital costs. However, due to the high CO_2 emissions from traditional production, producers and technology providers are now seeking lower-carbon alternatives.

One approach involves blending green hydrogen—produced via electrolysis—into existing plants, with some aiming for full replacement of fossil-based hydrogen. Technology providers are developing or partnering on electrolysis solutions to offer integrated systems.

Although the Haber-Bosch process remains central, powering the process using renewables (not just for the green hydrogen production, but also air separation and ammonia) introduces challenges around the high variability in renewable power generation. This is leading to innovation around flexible operation, with ammonia plant turndown capabilities as low as 10% of design rates, complemented by energy and/or hydrogen storage, and design optimisations intended to minimize the levelised cost of ammonia (LCOA).

4.9.2.1 Summary of changes

Compared to 2024 the ammonia plant capacity has been chosen to be in the typical commercial range where economies of scale are leveraged (2800tpd). Specific power consumption is slightly lower and based on GHD’s internal project reference. The above assumes uptime of 98% (excluding major shutdowns) as is typical for industry, and turndown to 10-30% of design flows as per previous OEM feedback. Plant capex is somewhat lower than previous reports at $530M and based on GHD’s internal database.

4.9.3 Selected hypothetical project

It has been assumed that the ammonia synthesis process would be used to produce green ammonia for export, whether as an energy source or as fertiliser or feedstock. Scope excludes upstream hydrogen production, compression and storage, as well as downstream ammonia storage.

Given the assumed export requirement, a mid-upper scale plant has been assumed, both to stockpile ammonia more rapidly, but also to achieve greater economies of scale and lower levelized cost.

Table 4.23 Configuration and performance – Ammonia production facility

Item	Unit	Value	Comment
Configuration			
Ammonia synthesis		Haber Bosch	
Nitrogen supply		Cryogenic air separation	
Cooling		Significant cooling requirements. Cooling approach tied to OEM specs and climate	
Waste heat recovery		Steam turbine	Utilise waste heat. Offset incoming power requirement
Performance			
Daily ammonia production (rated)	tpd	2,800	Mid-upper range for industry
Energy consumption	MWh/t NH3	0.75	Ammonia synthesis and air separation combined spec power at design flow. Increases significantly at turndown (depending on compressor configuration)
Hydrogen consumption	kg H2 per t NH3	178	Based on synthesis excluding losses and any heating requirements
Water consumption		Highly variable depending on cooling technology	
Annual Performance			
Annual ammonia output (typical)	T p.a.	1,000,000	
Stream days	Days p.a.	358	Per 98% uptime, excluding major turnarounds

Table 4.24 Technical parameters and project timeline – Ammonia production facility

Item	Unit	Value	Comment
Technical parameters			
Minimum turndown		10-30%	Varies by vendor, GHD project database
Synthesis loop pressure	Bar(g)	100+	Varies by technology provider
Catalyst		Iron-based	
Footprint		29000m2	
Project timeline			
Time for development	Months	24	Concept to FID
Project execution		30-36	FID to onstream
Economic life (Design life)	Years	25	
Technical life (Operational life)	Years	25	

Item	Unit	Value	Comment
Major turnaround cycle	Years	4	Typical – dictated by statutory inspections and rotating machinery

4.9.4 Development cost estimates

The following table provides CAPEX cost estimates for the defined ammonia production facility.

Table 4.25 Development cost estimates – Ammonia production facility

Item	Unit	Value	Comment
Pre FID Engineering	$	4,000,000	
Execution cost	$	530,000,000	

4.9.5 O&M cost estimates

The following table provides total annual O&M cost estimates for the defined ammonia production facility project.

Table 4.26 O&M cost estimates – Ammonia production facility

Item	Unit	Value	Comment
Operations and maintenance	$ per year	7,900,000	Assumed 1.5% of CAPEX p.a.

4.9.6 Retirement cost estimates

Retirement costs for the defined ammonia production facility are outlined in the table below.

Table 4.27 Retirement cost estimates – Ammonia production facility

Item	Unit	Value
Decommissioning, demolition & rehabilitation costs	$/MW (Gross)	242,000
Disposal costs	$/MW (Gross)	83,000
Recycling costs	$/MW (Gross)	(25,000)
Total retirement costs	$/MW (Gross)	300,000

4.10 Desalination plant

4.10.1 Overview

Desalination is the process of removing dissolved salts and other impurities from saline water (typically seawater or brackish water) to produce water suitable for industrial use. For large water consumers such as hydrogen production from water electrolysis, where a minimum of 9 kg H_2O/kg H_2 produced is required, desalination may be required.

The key components included in desalination are:

– Intake and outfall
– Water pre-treatment
– Desalination process
– Connection to water supply and
– Connection to power supply

Typically, desalination requires considerable electrical power to drive the process. Brine disposal and the environmental impact of brine disposal are important considerations for seawater desalination.

In Australia, there are large-scale desalination plants in Sydney, Perth, the Gold Coast, Victoria and Adelaide. These are all facilities to produce sustainable drinking water supply from seawater. A list of desalination plants in Australia, with capacities and startup dates is shown in Table 4.28.

Table 4.28 Desalination plants in Australia

Plant / Project	Location	Capacity (Megalitres/day)	Startup date	Notes
Perth Seawater Desalination Plant	Kwinana, Western Australia	130 ML/day	2006	One of WA's major desal sources.
Southern Seawater Desalination Plant (Binningup)	Binningup, Western Australia	270 ML/day	2012	Provides a large share of Perth's supply.
Sydney Desalination Plant	Kurnell, New South Wales	250 ML/day	2010	Now kept in standby / demand mode but "operational" status
Adelaide Desalination Plant (Port Stanvac)	Port Stanvac, South Australia	300 ML/day	2012	Major supplier in Adelaide.
Gold Coast Desalination Plant	Queensland (Tugun)	125 ML/day	2009	Operates at minimum production but can ramp up.
Victorian Desalination Plant (Wonthaggi)	Victoria	411 ML/day equivalent, if run full)	Operational (used when required)[252]	One of the largest in Australia
Alkimos Seawater Desalination Plant (Stage 1)	Alkimos, near Perth, WA	150 ML/day for Stage 1; expansion to 300 ML/day possible	Under construction: first water expected in 2028 for Stage 1	Will significantly boost Perth's desal capacity

4.10.2 SWRO process description

Reverse Osmosis (RO) is the removal of salts and other dissolved solids from seawater using high pressure to force water through semi-permeable membranes. Seawater Reverse Osmosis (SWRO) is the most common process used for seawater desalination, with 92% of new seawater desalination plants in 2018 being SWRO. It has been commercially used since the early 1970's[253]. The technology dominates due to relatively low power requirements (particularly compared to other desalination technologies) and modular scalability. SWRO can be used for both small and large scale desalination.

The process is as follows:

– Seawater is drawn through intake structures and pre-treated through dual-media filtration with coagulation/flocculation or ultrafiltration to remove colloids and organics and reduce turbidity/SDI. Cartridge filters provide final polishing to protect RO membranes.
– High pressure forces seawater through semi-permeable membranes. This separates fresh permeate water (with low dissolved solids) from concentrated brine, which is discharged to the ocean via diffusers to minimise environmental impact. Thin film composite membranes are used, which are stable and provides high separation performance.
– The permeate is remineralised to reduce corrosivity before blending with other supplies or distribution.
– Periodic chemical cleaning in place (CIP) is required to remove foulants from the membranes. Waste streams from the CIP and pretreatment backwash are small and treated before discharge with the brine.

The typical energy requirement for SWRO is 9-12 kWh/m^3.

[252] **https://www.water.vic.gov.au/water-sources/desalination?utm_source=chatgpt.com**
[253] **Sea Water Reverse Osmosis Plants SWRO- Definition | AWC**

4.10.3 Recent trends

In the past 20 years, there has been significant growth in the construction of desalination plants, with approximately 20,000 plants worldwide currently with a combined production capacity of more than 100 million m^3/day[254]. Most of this is for drinking water supply. This is an increase of 110% in desalination capacity in the past 20 years. Approximately 4.4 million m^3/day of new capacity was awarded in 2022[255].

There is significant research in both Brackish Water Reverse Osmosis (BWRO) and SWRO in the past 10 years, as is clear from the large number of publications and patents related to BWRO and SWRO (see Figure 4-3).

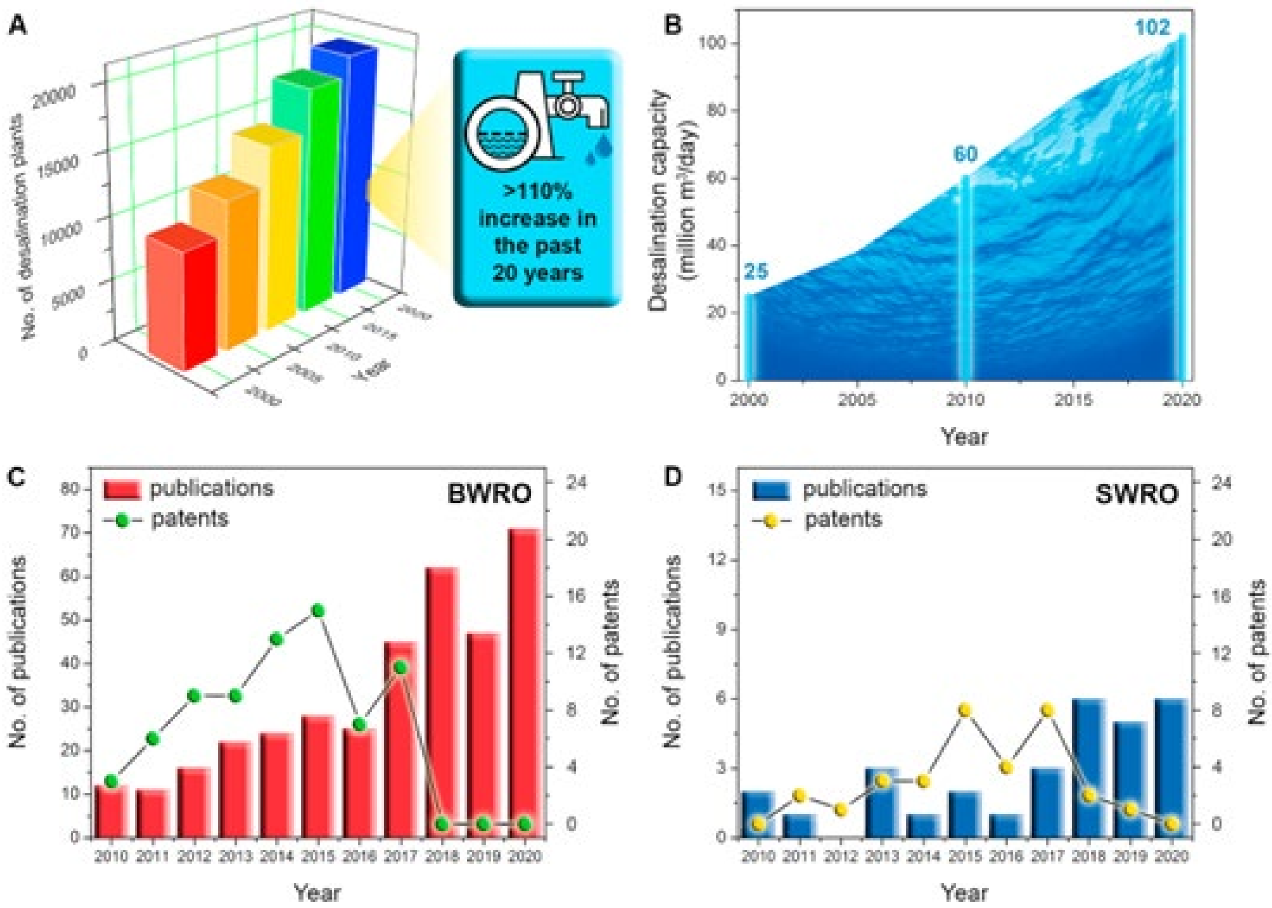


Figure 4-3 Growth of desalination in the past 20 years, showing (A) the number of desalination plants, (B) desalination capacity (million m^3/day), (C) number of publications and patents related to BWRO in the last 10 years and (D) SWRO in the last 10 years[256]

Wastewater reuse is also a strong trend in water treatment, with 12 million m^3/d of new capacity contracted globally in 2022. The global cumulative contracted and installed capacity by year for desalination and reuse of water has grown considerably from 2003 to 2023.

[254] Lim. Y.J. et. Al. (2021). Seawater desalination by reverse osmosis: Current development and future challenges in membrane fabrication – A review. Journal of Membrane Science 629:119292.
[255] IDRA. (2023-2024). Desalination and reuse handbook.
[256] Lim. Y.J. et. Al. (2021). Seawater desalination by reverse osmosis: Current development and future challenges in membrane fabrication – A review. Journal of Membrane Science 629:119292.

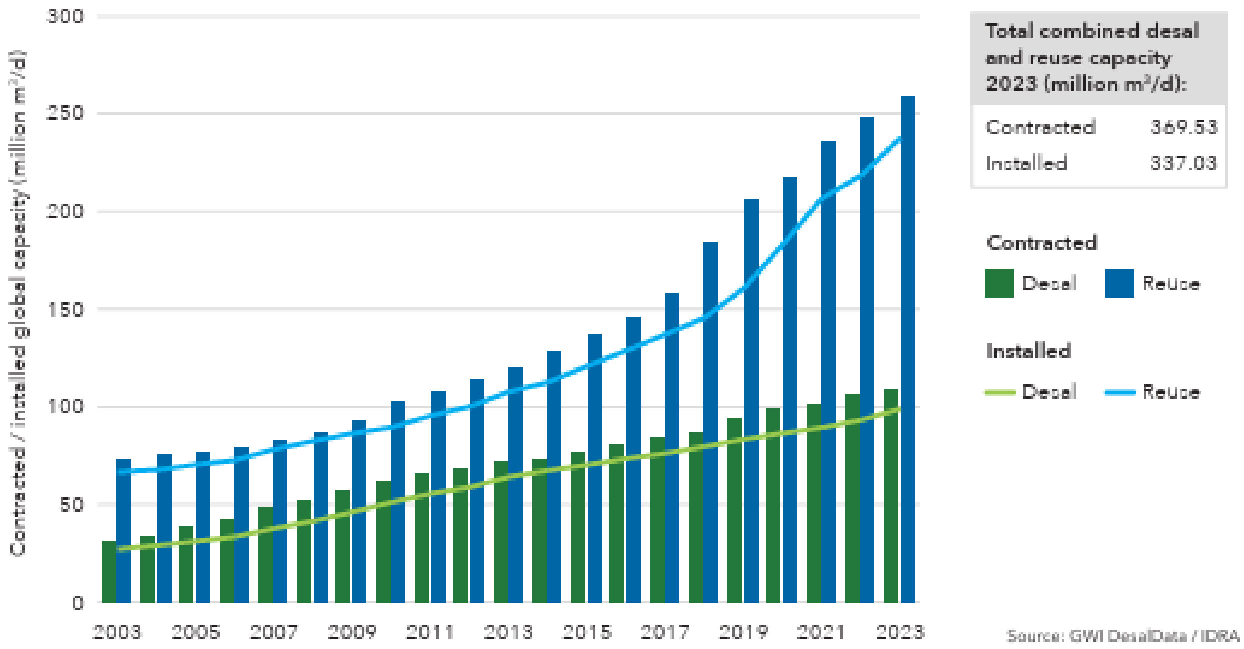


Figure 4-4 *Cumulative contracted and installed capacity by year, 2003-2023 for desalination and reuse capacity (million m^3/day)*[257]

As no heating or phase changes are required, the energy requirements are lower than for other desalination processes. The power demand for SWRO is driven by thermodynamics and pump power consumption. Initially, large improvements have been observed in power consumption for SWRO (see Figure 4-5), particularly with the implementation of multi-pass reverse osmosis with energy recovery. These improvements are the result of technical advances in membranes, pumps and energy recovery devices. Additional optimisation to reduce energy consumption further may be possible, for example through the development of low-pressure operation membrane and high efficiency energy recovery. However, any additional improvements are expected to be incremental only.

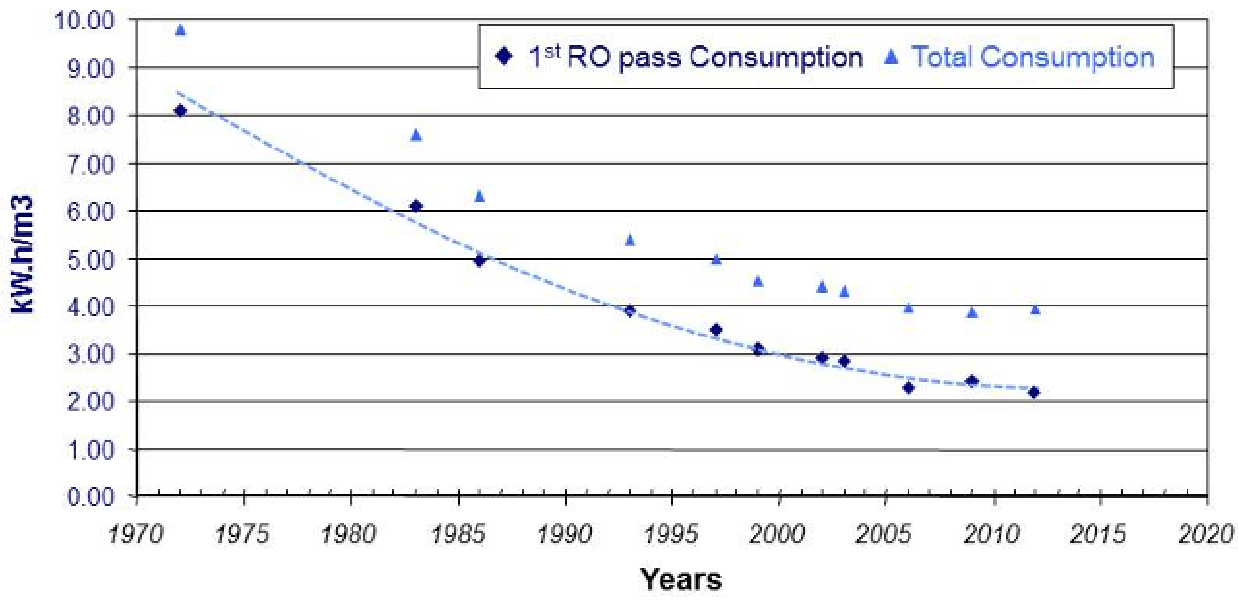


Figure 4-5 *Trends of energy reduction in SWRO*[258]

[257] IDRA. (2023-2024). Desalination and reuse handbook.
[258] Kunihara, M. and Takeuchi. H. (2018). SWRO-PRO System in "Mega-ton Water System" for Energy Reduction and Low Environmental Impact. Water, 10: 48.

Many other desalination technologies have been developed but not typically adopted due to operational complexity and higher energy consumption compared to SWRO, particularly for processes including thermal evaporation.

Desalination technologies are compared in Table 4.29, including typical capacities, energy consumption and applications.

Table 4.29 Desalination technologies comparison

Technology	Feedwater	Typical Capacity Range	Energy Consumption	Notes / Applications
Reverse Osmosis (RO)	Seawater, brackish supply	1,000 m^3/day – 500,000 m^3/day	2.5kWh/m^3 for RO, 3.5kWh/m^3 for full plant[259] when optimised for multi-pass RO 9-12 kWh/m^3 for standard configuration	Most widely used; membranes remove salts; can handle large-scale municipal or industrial water supply.
Multi-Stage Flash (MSF)	Seawater	5,000 – 500,000 m^3/day	13.5–25.5kWh/m^3[260]	Thermal process; used mainly in the Middle East; robust for large seawater plants; high energy consumption.
Multi-Effect Distillation (MED)	Seawater	500 – 100,000 m^3/day	6.5–11 kWh/m^3 [261]	More energy-efficient than MSF; uses multiple evaporator stages; suitable for large seawater plants.
Electrodialysis (ED / EDR)	Brackish water	100 – 10,000 m^3/day	2–4 kWh/m^3 electrical	Uses electric field to move ions; effective for low-salinity brackish water; limited for seawater due to high TDS.
Thermal Vapor Compression (TVC)	Seawater, brackish water	100 – 10,000 m^3/day	7–12 kWh/m^3 [262]	Small to medium-scale industrial applications; integrates with waste heat streams.
Solar Desalination / Humidification-Dehumidification (HDH)	Seawater	10 – 1,000 m^3/day	5–15 kWh/m^3 thermal (solar)	Small-scale, off-grid applications; low maintenance; low environmental footprint.

SWRO is expected to continue to dominate the market, and incremental improvements rather than major advancements are expected in the foreseeable future.

4.10.3.1 Summary of changes

No material changes were observed in the technology or costs from the 2024 report.

4.10.4 Selected hypothetical project

The selected hypothetical project is a large-scale SWRO plant in Australia with a production capacity of 40,000 ML/year and located less than 2 km away from the feed source, with a recovery ratio of 0.4.

A standard configuration is assumed; that is no multi-pass configuration has been assumed which would decrease the power consumption significantly.

[259] GHD project information
[260] Reif, J.H. and Alhalabi, W. (2015). Solar-thermal powered desalination: Its significant challenges and potential. Renewable and Sustainable Energy Reviews 48:152-165.
[261] Reif, J.H. and Alhalabi, W. (2015). Solar-thermal powered desalination: Its significant challenges and potential. Renewable and Sustainable Energy Reviews 48:152-165.
[262] Reif, J.H. and Alhalabi, W. (2015). Solar-thermal powered desalination: Its significant challenges and potential. Renewable and Sustainable Energy Reviews 48:152-165.

4.10.5 Cost estimates

The following table provides CAPEX and OPEX cost estimates for the defined desalination plant project.

Table 4.30 Cost estimates – Desalination plant

Item	Unit	Value	Comment
CAPEX			
Relative cost	$	1,720,000,000 - 2,730,000,000	Escalated from the 2024 value reported[263]. Energy recovery has not been included in the CAPEX, and is unlikely to be adopted soon due to high added complexity and additional CAPEX, and relatively small energy gains
Total EPC cost			
– Equipment cost	%	20	
– Construction cost	%	80	
CAPEX construction cost breakdown (% of construction cost)			
– Intake and brine discharge structure	%	30	
– Pre-treatment	%	15	
– Reverse osmosis plant	%	25	
– Post-treatment (remineralisation)	%	2	
– Product storage and distribution	%	10	
– Electrical and instrumentation	%	8	
– Civil/site and permits	%	10	
OPEX (Annual)			
Operations and maintenance	$ per year	13,000,000	Escalated from 2024 report numbers by CPI
Power	$ per year	22,200,000	Escalated from 2024 report numbers by CPI
Chemical	$ per year	8,900,000	Escalated from 2024 report numbers by CPI
Labour	$ per year	8,900,000	Escalated from 2024 report numbers by CPI

4.11 Water treatment (demineralisation) for hydrogen production

4.11.1 Overview

Hydrogen electrolysers require ultrapure water to operate efficiently and reliably. Impurities such as dissolved salts, minerals, organics, and particulates remaining, even if present at modest levels, can accumulate and concentrate in the system, as the water molecules themselves are progressively converted to hydrogen and oxygen. They can damage key components like membranes, electrodes, and catalysts. These contaminants may lead to scaling, corrosion, or fouling, which reduce performance, increase maintenance needs, and shorten system lifespan.

High-purity water ensures consistent hydrogen output, protects system integrity, and supports long-term operational stability. Demineralised water feeding an electrolyser could have a Total Dissolved Solids (TDS) of < 0.1mg/L, whereas 2nd pass Reverse Osmosis permeate on a desalination plant could have TDS which is 1-2 orders of magnitude greater, at 5-50mg/L (though variable on a case-by-case basis).

[263] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024

4.11.1.1 Summary of changes

Compared to 2024, the demineralised water capacity requirement has been set to 40m3/day for a 10MW electrolyser module (nominally 10L of demin per kg of water) in line with stoichiometry and allowing for moderate losses, which is lower than 2024. Power consumption is relatively modest at approximately 0.12MWh/day given modest power needs to treat potable water to demin, significantly less than previously reported, and capex is also notably lower than previously reported, as is power cost, the latter assuming a unit rate of $0.10/kWh in the present iteration.

4.11.2 Processing technology

The water treatment process typically involves three key stages (noting there may be overlap with the above Desalination step in the case of seawater or brackish water, in terms of treatment steps):

1. Pre-treatment which removes suspended solids, colloids, and organic matter. Technologies include:
   a. Ultrafiltration (UF)
   b. Ion exchange softening
   c. Biofouling control
2. Demineralisation, which eliminates dissolved salts and minerals using Reverse Osmosis (RO) (often multi-pass systems, say, in the case of needing desalination)
3. Polishing, which represents the final purification to achieve ultrapure water quality, using Electrodeionization (EDI) and Mixed-bed ion exchange resins

These systems are tailored to the feedwater source (e.g., potable water, surface water, wastewater, or seawater) and electrolyser type, ensuring consistent water quality and minimizing operational risks. There may also be buffer storage included in scope, to even out discrepancies between supply and demand, though this needs to be balanced against any impacts on water quality due to residence time.

Often the front-end steps in this process are combined with the treatment needed for the make-up water for any cooling circuit, in which case these steps are oversized accordingly.

4.11.3 Selected hypothetical project

The hypothetical project involves a demineralised water treatment plant designed to produce high-purity water for a 10 MW electrolyser, given this is a typical building block of larger facilities. It assumes potable water or high quality surface water as the feed. Key process parameters are outlined in the table below. Water balance is calculated using a recovery ratio which depends on the actual water quality and any other treatment steps – but as a guide this could typically be of the order of 85-90% for this type of source.

The main wastewater output is brine, with smaller volumes generated from membrane backwash and chemical Clean-In-Place (CIP).

Table 4.31 Technical parameters – Water treatment plant

Item	Unit	Value	Comment
Demineralised water requirement	M^3 per day	40	9kg demin per kg of H2 per stoichiometry, typically designed for 10kg/kg
Feed water requirement	M^3 per day	46.5	
Brine production	M^3 per day	6.5	
Power consumption	MWh/day	0.12	Based on GHD internal database
Recovery	%	86	

4.11.4 Cost estimates

The following table provides CAPEX and OPEX cost estimates for the defined water treatment plant project.

Table 4.32 Cost estimates – Water treatment plant (demineralisation)

Item	Unit	Value	Comment
CAPEX			
Total EPC cost	$	400,000 – 800,000	
– Equipment cost	%	40	Industry typical range for packaged process plant
– Construction cost	%	60	
O&M (Annual)			
Maintenance	$ per year	8,000-15,000	Circa 2.5% of CAPEX
Power	$ per year	3,000-6,000	Dependent on specific treatment and power price
Chemical	$ per year	< 1,000	Dependent on specific treatment
Labour	$ per year	15,000-25,000	Dependent on broader site manning model, potential shared resource, automated system

5. Hydropower and pumped hydro energy storage

5.1 Overview

Technologies within this section include:

– Conventional hydropower
– Pumped hydro energy storage

The following sections outline the typical options, recent trends, technical parameters, and cost parameters for these technologies. The information listed within the respective tables has been used to populate the 2025 Dataset in Appendix A.

Hydropower and pumped hydro energy storage (PHES) play a foundational role in Australia's transition to a low-emissions, reliable energy system. Hydropower, one of the oldest and most mature renewable technologies, converts the kinetic energy of flowing water into electricity and currently contributes around 5–7% of Australia's total electricity generation. Despite Australia's arid climate, hydropower has played a foundational role in the energy mix for over a century, with major developments such as the Snowy Mountains Hydro-electric Scheme, Hydro Tasmania's integrated hydropower system and AGL's stations in NSW and Victoria. These large-scale facilities provide both base and peak load power, offering grid stability and flexibility.

PHES, an energy storage system rather than generation, operates by moving water between two reservoirs at different elevations to store and release energy as needed. This technology is particularly valuable for its ability to provide long-duration, dispatchable energy storage, helping to balance the grid during periods of high demand or low renewable generation. With round-trip efficiencies of around 75-80% and lifespans exceeding 50–100 years, PHES offers a cost-effective and sustainable solution for large-scale energy storage.

Australia currently has three major PHES facilities—Tumut 3, Wivenhoe, and Shoalhaven—with a combined capacity of approximately 1.6 GW. Several new projects are underway, including Snowy 2.0 (2,200 MW), Kidston (250 MW), Borumba (up to 2,000 MW), and Phoenix Pumped Hydro (800 MW), which collectively represent a significant expansion of national energy storage capacity. AEMO's 2024 ISP[264] forecasts suggest that up to 36 GW of energy storage will be needed by 2035 to support the transition to net zero. Encouragingly, the Australian National University[265] has identified over 22,000 potential PHES sites across the country, many of which are "off-river" and do not require new dams, reducing environmental impact and increasing development flexibility.

Despite its promise, PHES faces several constraints. High capital costs, long development timelines, complex environmental approvals, and water licensing challenges can hinder project viability. Additionally, securing land tenure and social licence—particularly in areas with cultural heritage significance or active native title—requires careful stakeholder engagement. Nonetheless, government support through schemes like the Long-Term Energy Service Agreements (LTESA) and the Capacity Investment Scheme (CIS) is helping to de-risk investment and accelerate deployment. With its ability to complement intermittent renewables and provide grid stability, PHES remains a cornerstone technology in Australia's evolving energy landscape.

5.2 Conventional hydropower

5.2.1 Overview

The Snowy Mountains Scheme alone accounts for nearly half of Australia's hydroelectric capacity, featuring 16 major dams, seven power stations, and 145 km of trans-mountain tunnels. Tasmania's hydropower network, which includes 50 dams and 29 power stations, supplies most of the state's electricity and connects to the mainland grid via the Basslink interconnector. Hydropower also supports broader water management objectives,

[264] AEMO (2024) Integrated System Plan for the National Electricity Market
[265] Andrew Blakers, Bin Lu and Matthew Stocks, Australian National University, (2017) 100% renewable electricity in Australia, **http://www.sciencedirect.com/science/article/pii/S0360544217309568**

including flood control, irrigation, and water supply. However, geographic and climatic constraints limit further expansion.

Hydropower is particularly valuable for its rapid response capabilities, low operating costs, and minimal greenhouse gas emissions. With over 120 operating hydroelectric stations and a total installed capacity of approximately 8.5 GW in Australia, conventional hydropower remains a reliable and dispatchable source of renewable energy.

Most viable sites have already been developed, and new projects face high capital costs, long lead times, and environmental approval challenges. Nonetheless, hydropower's proven reliability and ability to complement intermittent renewables like wind and solar make it a critical component of Australia's energy transition strategy.

5.2.2 Typical options

It is unlikely that any new grid scale conventional hydropower will be developed in Australia. Most of Australia's conventional hydropower assets are over 30 years old, with limited scope for new dam-based developments due to environmental and geographic constraints. However, incremental upgrades—such as turbine replacements, control system modernisation, and efficiency improvements—are being considered across the portfolio of Australian hydropower assets.

5.2.3 Recent trends

Recent trends in conventional hydropower upgrades in Australia reflect a strategic shift toward modernising existing assets rather than building new large-scale dams. This is driven by environmental constraints, high capital costs, and the need for flexible, dispatchable renewable energy. For example, Hydro Tasmania has committed $1.6 billion over the next decade to upgrade and modernise its existing hydropower assets[266]. This includes:

– Tarraleah Redevelopment Project: A full rebuild to improve flexibility and increase output.
– Rowallan Power Station: Completed a $30 million refurbishment to extend operational life and improve reliability.
– Edgar Dam: Approved for structural upgrades to meet modern safety and performance standards.

These upgrades aim to improve efficiency, extend asset life, and enable better integration with intermittent renewables.

Snowy Hydro's primary focus has been on the Snowy 2.0 expansion, which is a pumped hydro project. However, the broader initiative includes upgrades to existing infrastructure within the Snowy Mountains Scheme, which has been operational for over 50 years. Snowy Hydro claims the upgrades will extend the operational life of existing assets by up to 70 years, improve system flexibility, and support grid reliability for future generations.

AGL has undertaken both conventional hydropower upgrades and feasibility studies for pumped hydro conversions of existing assets. At the Clover Power Station (Kiewa Scheme), AGL invested $40 million over five years (2022–2026) for replacement of turbines, generators, and inlet valves. This increased throughput from 120 ML/h to 140 ML/h and provided a 14 MW boost in capacity, improving the efficiency and reliability of the oldest station in the Kiewa Scheme, commissioned in 1945[267].

These efforts reflect a broader trend in Australia's energy sector: modernising conventional hydropower assets to improve performance and exploring hybridisation with pumped hydro to meet future storage needs.

Industry leaders and the International Hydropower Association[268] have called for a National Hydropower Strategy to unlock investment and accelerate development. Key recommendations include:

– Streamlining environmental approvals.
– Supporting public-private partnerships to share development risk.
– Creating long-term revenue certainty through market mechanisms.

[266] Hydro Tasmania media release 8 Aug 2024
[267] AGL media release 25 July 2022
[268] International Hydropower Association (IHA 2024) Enabling New Pumped Storage Hydropower – A guidance note for key decision makers to de-risk pumped storage investments.

These reforms aim to make new PHES development and conventional hydropower upgrades more viable and attractive to investors.

5.2.3.1 Summary of changes

The 2024 report was based on a hypothetical 100MW upgrade. The new 2025 reference project is based on published data for Hydro Tasmania's 190MW Tarraleah Redevelopment Project which is larger and likely more complex than envisaged in 2024. Most parameters are similar when normalised by installed capacity.

5.2.4 Selected hypothetical project

The hypothetical project is based on published information for Hydro Tasmania's Tarraleah Redevelopment Project[269]. The project is a cornerstone of the state's Battery of the Nation initiative, aimed at modernising ageing hydropower infrastructure to meet the demands of a rapidly evolving energy market. Originally commissioned in the 1930s, the Tarraleah scheme currently generates around 7.3% of Tasmania's electricity but faces growing challenges due to ageing assets, inflexible operations, and environmental risks.

The redevelopment proposes a complete overhaul, including the construction of a new, higher-capacity power station adjacent to the existing one, and the replacement of old canals and penstocks with a pressurised pipeline and tunnel system. This will allow the scheme to generate 30% more electricity from the same water and respond more rapidly to market fluctuations.

The estimated cost of the project is $1.96 billion (2024 dollars). This is a relatively high cost of $10M/MW reflecting a near complete reconstruction of the entire scheme. Conversely the Clover Power Station upgrade by AGL, as discussed above, provided an additional 14MW at a cost of $40M or $2.9M/MW. This demonstrates the wide variation in possible scope and costs for these types of projects. While the description below is based on the Tarraleah development, the adopted costs are the average of the two examples noted above to reflect what might be representative for typical upgrade projects.

Table 5.1 Configuration and performance – Conventional hydropower

Item	Unit	Value	Comment
Configuration			
Technology / OEM		Francis turbine	Several OEMS exist including Andritz, GE Vernova, Voith, Fuji Electric, Toshiba, Hitachi, Mitsubishi.
Make model		Various	Supplier specific and customised to site
Unit size (Nominal)	MW	95 MW	
Number of units		2	
Performance			
Total plant size (Gross)	MW	190	
Auxiliary power consumption	%	1	
Total plant size (Net)	MW	188	
Seasonal rating – Summer (Net)	MW	188	
Seasonal rating – Not Summer (Net)	MW	188	
Annual Performance			
Average planned maintenance	Days / year	5	
Equivalent forced outage rate	%	1	
Effective annual capacity factor (P50, year 0)	%	50	Example specific to Tarraleah hydro
Annual generation	MWh	820,000	
Annual degradation over design life	% pa	<0.1	

[269] Hydro Tasmania 2025 Tarraleah Redevelopment Business Case Overview

Table 5.2 Technical parameters and project timeline – Conventional hydropower

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW/min	400	Spinning to full generation or reverse in 15-20 secs.
Ramp down rate	MW/min	400	
Start-up time	Min	<1.0	
Min stable generation	% of installed capacity	25	Stable operation to 50% of one unit
Project timeline			
Time for development	Years	2-4	Feasibility assessment to FID
First year assumed commercially viable for construction	Year	2026	
EPC programme	Years	4	For NTP to COD depending on extent of upgrade / refurbishment
– Total lead time	Years	0.5	
– Construction time	Weeks	208	
Economic / Design life	Years	100	
Technical life (Operational life)	Years	100	

5.2.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined conventional hydropower project.

The cost estimates are based on the published cost in Hydro Tasmania's Tarraleah Redevelopment Project[270].

Table 5.3 Development cost estimates – Conventional hydropower

Item	Unit	Value	Comment
CAPEX construction			
Relative cost	$/kW (Gross)	6,500	Cost varies significantly with scope. Range of 3,000 - 10,000 is between AGL's turbine upgrades and Tarraleah full redevelopment of a complex site.
Total EPC cost	$	1,960,000,000	Sourced from Hydro Tasmania 2025[271]
– Equipment cost	$	490,000,000	25% of total EPC cost
– Construction cost	$	1,470,000,000	75% of total EPC cost
Other costs			
Cost of land and development	$	Nil	Assume land is already owned and no offsets required.
Fuel connection costs	$	Nil	

5.2.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined conventional hydropower project.

Operating costs are assumed to be similar to pumped hydro. Entura[272] estimated O&M costs for PHES based on several US and Australian reviews, validated against Hydro Tasmania's portfolio data. They concluded that

[270] Hydro Tasmania 2025 Tarraleah Redevelopment Business Case Overview
[271] Hydro Tasmania 2025 Tarraleah Redevelopment Business Case Overview
[272] Entura (2018) Pumped Hydro Cost Modelling

variable O&M is not meaningful for hydropower projects, as it does not take into account the most damaging aspects of operation. As such, fixed O&M costs only should be used, and recommended a single value of $16,000/MW/yr for stations with installed capacity greater than 100MW and less than 50 years old. This has been escalated to 2025 values using ABS cost index data[273] (index 3109).

Table 5.4 O&M cost estimates – Conventional hydropower

Item	Unit	Value	Comment
Fixed O&M cost	$/MW/year (Net)	20,000	Based on Entura (2018)[274]
Variable O&M cost	$/MWh (Net)	0	Not meaningful for hydro
Total annual O&M cost	$	3,760,000	

5.2.7 Retirement cost estimates

Retirement costs for the defined conventional hydropower project are outlined in the table below.

Retirement costs are assumed to be similar to pumped hydro. The retirement of conventional hydropower will require decommissioning of waterways and plant before dismantling of the powerhouse can proceed. Dewatering of the system needs to be undertaken so that the waterways can be permanently isolated at the intakes and then the main plant in the powerhouse decommissioned.

On completion of removal of underground plant, the cavern can be used for disposal of inert material as a result of surface demolition and rehabilitation. Upon completion of disposal and rehabilitation works the access portals and shafts can be sealed against human access.

The high-level process for retirement of conventional hydropower will include:

– Isolation of power waterways.
– Dewatering of power waterways.
– Decommissioning of plant within powerhouse.
– Plugging and sealing intake structures. Removal of intake gates.
– Dismantling and removal of non-embedded components of main plant and balance of plant in powerhouse and transformer caverns.
– Dismantling and removal of surface plant including transmission lines and switchyard in parallel with underground works.
– Removal of foundations and complete rehabilitation of surface works.
– Disposal of non-recyclable inert materials within underground cavern.
– Plugging and sealing of shafts and tunnels with reinforced mass concrete plugs.

Retirement cost estimate details for conventional hydropower can be found in Appendix C.

Table 5.5 Retirement cost estimates – Conventional hydropower

Item	Unit	Value	Comment
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	9,000	Estimate from GHD[275]
Disposal costs	$/MW (Net)	4,000	Estimate from GHD[276]
Recycling costs	$/MW (Net)	(2,500)	
Total retirement costs	$/MW (Net)	10,500	

[273] Australian Bureau of Statistics, Producer Price Indexes, Australia June 2025 - Output of Heavy and civil engineering construction prices, quarterly percentage change and index
[274] Entura (2018) Pumped Hydro Cost Modelling
[275] GHD (2025) Energy Technology Retirement Cost and O&M Estimate Review
[276] GHD (2025) Energy Technology Retirement Cost and O&M Estimate Review

5.3 Pumped hydroelectric storage

5.3.1 Overview

PHES is the largest and most technologically mature form of medium and long duration energy storage currently available that accounts for approximately 95% of total existing energy storage capacity worldwide.

PHES schemes allow energy to be stored using the potential energy between two water reservoirs separated in elevation, acting like a battery. This is undertaken by storing water in a 'top reservoir', water is released and passed through turbines, generating energy. The water is then stored in a 'bottom reservoir', where it can be pumped back up to the 'top reservoir' either during off peak periods, when there is excess power in the grid, or using alternative methods of renewable energy such as solar. A schematic of a PHES scheme is shown in Figure 5-1.

A single electrical machine can function as either a motor, driving a pump, or a generator, being driven by a turbine. In most modern schemes, the pump and turbine are the same item, operating in either the forward or reverse rotational direction, a so-called "reversible pump-turbine". Although in most of the existing older installations in Australia, the pump and the turbine are mounted separately on the same shaft and rotate only in one direction, this is called a 'ternary machine'.

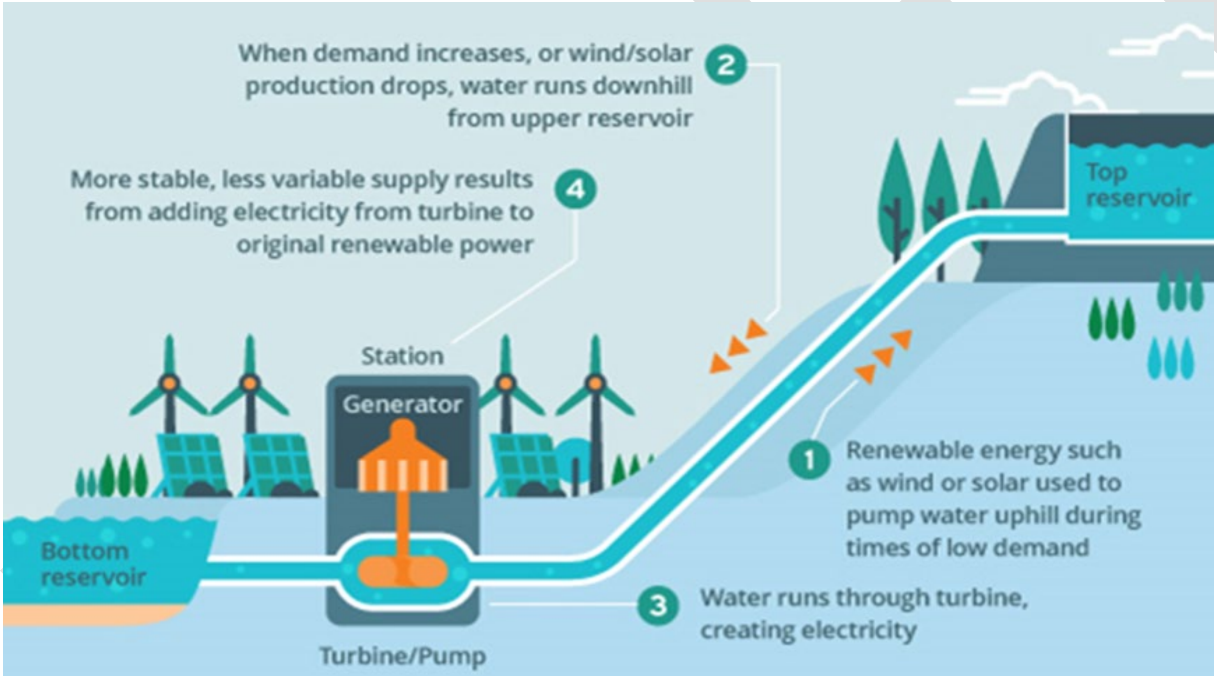


Figure 5-1 Pumped Hydro Energy Storage process[277]

5.3.2 Typical options

Potential sites to facilitate PHES can be categorised as:

– **Greenfield**: or closed loop system, with two new reservoirs located off-river, and not connected to an existing reservoir, an example project is shown in Figure 5-2. International projects have commonly adopted greenfield arrangements, as have several proposed schemes in Australia.

– **Bluefield**: one or both reservoirs utilise a part, or the entirety of, an existing reservoir or reservoirs, an example project is shown in Figure 5-3. Most PHES facilities in Australia have been bluefield, taking advantage of one or two existing water reservoirs. Snowy 2.0 will connect two existing reservoirs within the Snowy Hydro system.

– **Mine-Void**: one or both reservoirs utilise an existing mine void. Kidston PHES, currently under construction in Queensland exploits the elevation difference between two existing mine pits to create a PHES scheme.

[277] Image sourced from Australian Renewable Energy Agency

Reservoir types can be described as:

– **Turkey's Nest:** above ground reservoir with embankment around the full perimeter
– **Gully Dam:** reservoir is formed by dam across a valley. A 'dry gully' is a gully which typically has no surface flow, while a 'wet gully' has constant or frequent ephemeral flow.

The energy generation capacity of a PHES scheme is only limited by the amount of water that can be stored and elevation difference between the two reservoirs. As discussed in Section 5.3.2.1, optimal PHES schemes can have very large storage capacities and durations. These optimal schemes are those with suitable sites for large reservoirs, reasonable head difference between reservoirs (typically more than 250m) and a small horizontal distance and meet environmental and social requirements.

Figure 5-2 Example Greenfield site

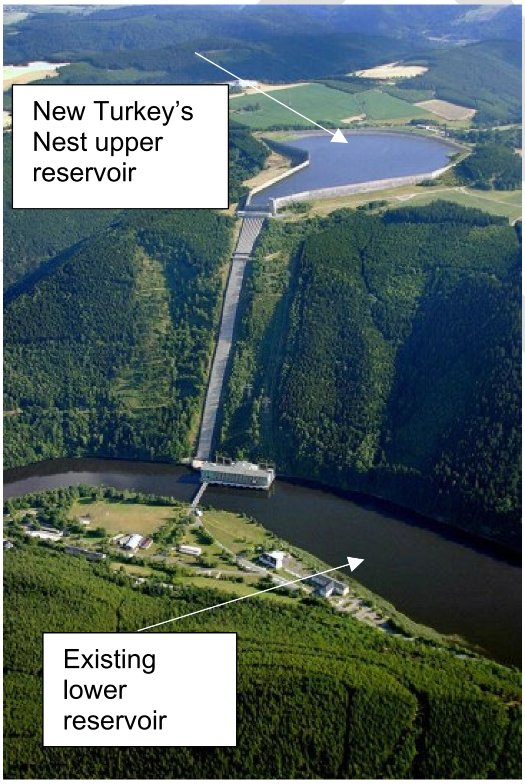


Figure 5-3 Example Bluefield site

5.3.2.1 Optimal PHES Schemes

PHES schemes are typically associated with high capital costs due to their scale and many site-specific development considerations. Given the wide range of potential project capital costs, it would be most reasonable to focus on projects at the lower end of the capital cost scale that represent optimal pumped hydro sites that can be delivered into the system.

Some of the criteria for identification of an optimal PHES scheme are listed in Table 5.6. A site that is favourable for the majority of the criteria is likely suitable for further consideration as a potential optimal PHES scheme. While not meeting these criteria may identify fatal flaws where development may not be preferrable.

Table 5.6 Criteria for identification of an optimal PHES scheme

Criteria	Considerations
Topography	Available head Reservoir geometry Waterway length / head ratio Site access and constructability
Geology	Ground conditions, groundwater conditions, lithology and structural considerations
Hydrology	Likely availability of water for initial fill and top ups Water quality Flood and weather risk Impacts on downstream catchments
Network	Proximity to transmission lines and substations
Social	Impact on recreational areas Amenity impacts – noise, visual, proximity to sensitive locations Community support Labour availability
Environment	Potential environmental impacts on biodiversity and ecology Cultural heritage
Planning	Current land use and zoning Land access / acquisition Permit approvals

5.3.3 Recent trends

5.3.3.1 The need for PHES

CSIRO prepared a Renewable Energy Storage Roadmap in 2023 for Australia[278]. The study determined that PHES is internationally deployed and commercially competitive and capable of medium (4-12 hours), long (12-100 hours) and seasonal (>100 hours) grid storage. A key advantage is the economy of scale, with large opportunity to reduce cost per unit of energy (MWh) for larger systems.

Figure 5-4 from the CSIRO Renewable Energy Storage Roadmap[279] identifies that PHES likely has commercial applicability for all storage durations greater than 4 hours and is the only technology with a maturity (commercial readiness index CRI of 6 indicating competitive commercial deployment) appropriate to supply long duration storage.

[278] CSIRO (2023) Renewable Energy Storage Roadmap
[279] CSIRO (2023) Renewable Energy Storage Roadmap

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

Figure 5-4 Summary of applicable durations for energy storage technologies in utility scale grid applications[280] [281]

5.3.3.2 Existing and proposed PHES schemes

Australia

Australia has a long history of PHES operation with the following three schemes being constructed in the 1970s and 1980s:

- Wivenhoe (570 MW / 5700 MWh, 10 hours)
- Shoalhaven (240 MW, 24 hours)
- Tumut 3 (900 MW) – Conventional hydropower scheme with three of six units installed as pump turbines for PHES. Generation duration depends on conventional hydropower operation but could be multi-day.

Australia is undergoing a significant expansion of its pumped hydro infrastructure to enhance energy storage and grid stability, particularly as the country transitions to a higher proportion of renewable energy. Schemes currently under construction in Australia include:

- Snowy 2.0 (2000 MW / 350,000 MWh, 175 hours) – Very long duration storage capable of supplying energy for a week, supported by the Federal Government. The project involves linking two existing reservoirs (Tantangara and Talbingo) with 27 km of tunnels and constructing a new underground power station.
- Kidston (250 MW / 2000 MWh, 8 hours) is being developed by Genex /J-Power on a former gold mine in North Queensland, Australia. It utilizes two mining voids at different elevations as reservoirs, with a tunnelled waterway and underground powerhouse.
- Borumba Pumped Hydro (2000MW / 48,000 MWh, 24 hours) being developed by Queensland Hydro is currently undergoing early works onsite.

GHD carried out a search of publicly issued statements on pumped hydro projects to prepare a database of publicly announced projects in Australia[282]. The search identified 40 proposed projects (excluding those listed above), with a combined capacity of more than 22,000 MW and 329,000 MWh of energy storage. This is close to the total energy storage requirement in the NEM by 2050 identified in the AEMO 2024 ISP[283].

GHD then studied the potential maximum build capacity for PHES in the NEM[284] using the ANU 2017 PHES atlas[285] and applying GIS screening to identify optimal sites. A **Maximum Build Capacity of 124,600 MW** and a **total energy storage capacity of 7,460 GWh** was identified with sites shown in Figure 5-5. This represents more

[280] CSIRO (2023) Renewable Energy Storage Roadmap
[281] Figure continues in CSIRO report but has non commercially mature schemes with CRI of 1 to 3
[282] GHD (2025) AEMO Pumped Hydro Energy Storage Parameter Review
[283] AEMO (2024) Integrated System Plan for the National Electricity Market
[284] GHD (2025) AEMO Pumped Hydro Energy Storage Parameter Review
[285] Andrew Blakers, Bin Lu and Matthew Stocks, Australian National University, (2017) 100% renewable electricity in Australia, **http://www.sciencedirect.com/science/article/pii/S0360544217309568**

than 10 times the total energy storage requirement identified in the AEMO 2024 ISP[286]. Hence, total energy storage (GWh) with optimal PHES sites is not a limitation for future planning.

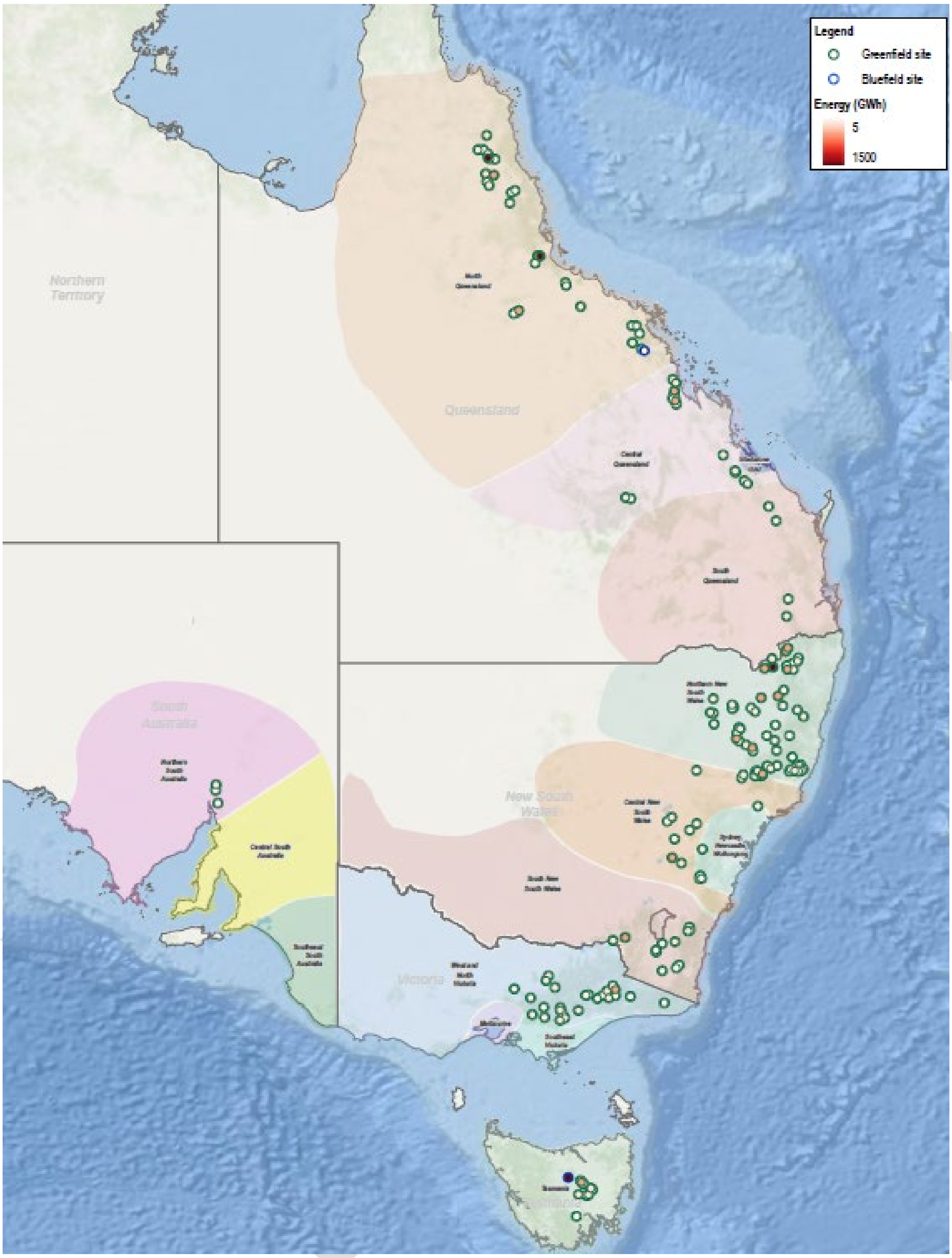


Figure 5-5 Map of PHES Maximum build capacity (124,600 MW) in the NEM[287]

Industry leaders and the International Hydropower Association[288] have called for a National Hydropower Strategy to unlock investment and accelerate development. Key recommendations include:

– Streamlining environmental approvals.

[286] AEMO (2024) Integrated System Plan for the National Electricity Market
[287] GHD (2025) AEMO Pumped Hydro Energy Storage Parameter Review
[288] International Hydropower Association (IHA 2024) Enabling New Pumped Storage Hydropower – A guidance note for key decision makers to de-risk pumped storage investments.

– Supporting public-private partnerships to share development risk.
– Creating long-term revenue certainty through market mechanisms.

These reforms aim to make new PHES development and conventional hydropower upgrades more viable and attractive to investors.

International projects

The International Hydropower Association[289] (IHA) notes that Pumped Storage Hydropower is the largest form of renewable energy storage, with nearly 200 GW installed capacity with over 400 projects in operation. The IHA database presents a global portrait of PHES in operation, under construction as well as projects that are planned. Figure 5-6 shows PHES projects in operation (green circles) under construction (blue circles) and planned (yellow circles) with the size of the circles displayed indicating the installed capacity.

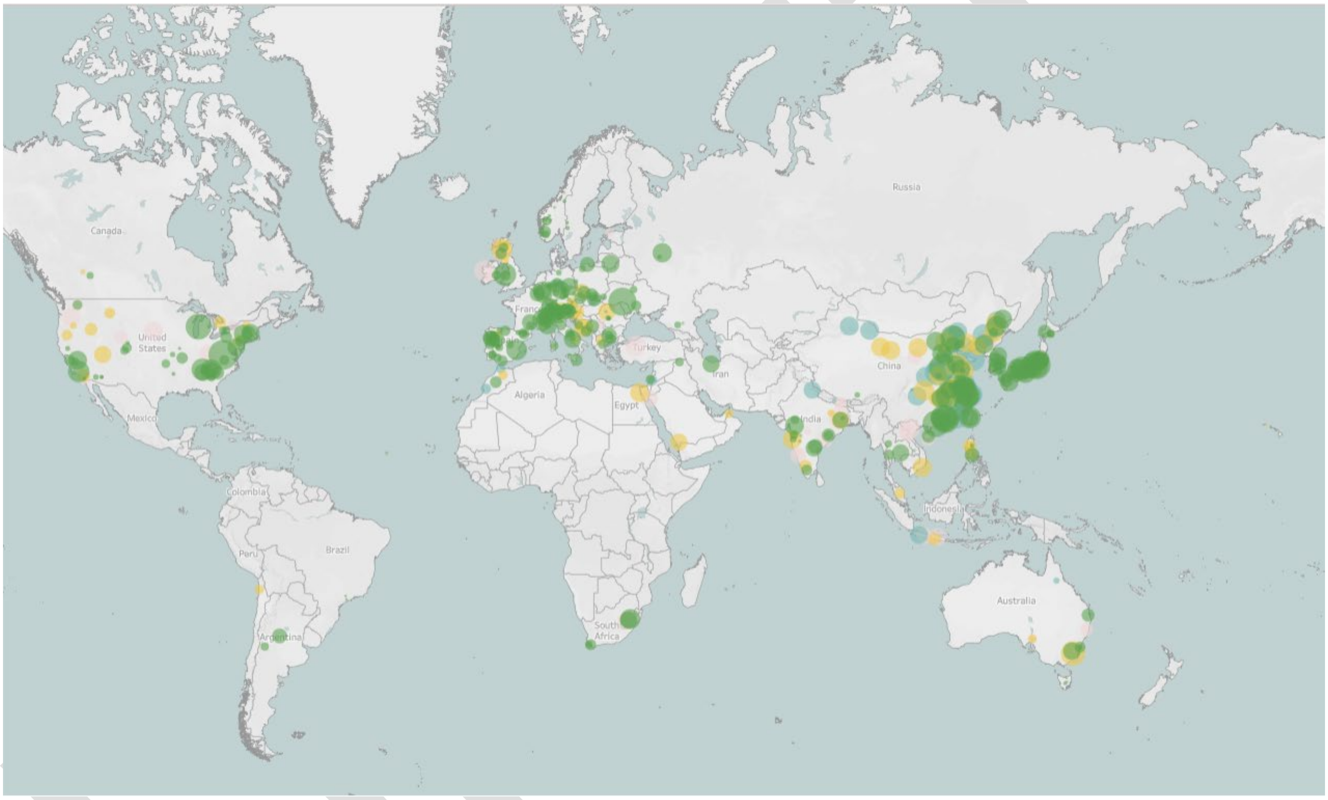


Figure 5-6 PHES in operation (green), under construction (blue) and planned (yellow) according to the IHA[290]

The number of sites shown in Figure 5-6 is summarised in Table 5.7. Note that GHD has identified certain sites currently under construction that are not shown in Figure 5-6, particularly in China.

Table 5.7 Number of PHES sites internationally

Continent	In operation	Under construction	Planned
Europe	164	5	16
Asia	103	32	35
Americas	40	0	12
Africa	5	2	2
Oceania	3	2	2
Total	**315**	**41**	**67**

[289] International Hydropower Association (IHA 2024) Enabling New Pumped Storage Hydropower – A guidance note for key decision makers to de-risk pumped storage investments
[290] International Hydropower Association (IHA 2024) Enabling New Pumped Storage Hydropower – A guidance note for key decision makers to de-risk pumped storage investments

The approximate year of commissioning (or forecast year of commissioning) of these global PHES projects is shown in Figure 5-7. PHES has been constructed at a steady rate as the preferred energy storage system to balance large baseload systems over more than half a century, but the transition to intermittent renewables requiring storage is clearly evident in the large uptake of new PHES projects in this decade. It can be anticipated that similar increase in demand for new PHES will continue in the next decade.

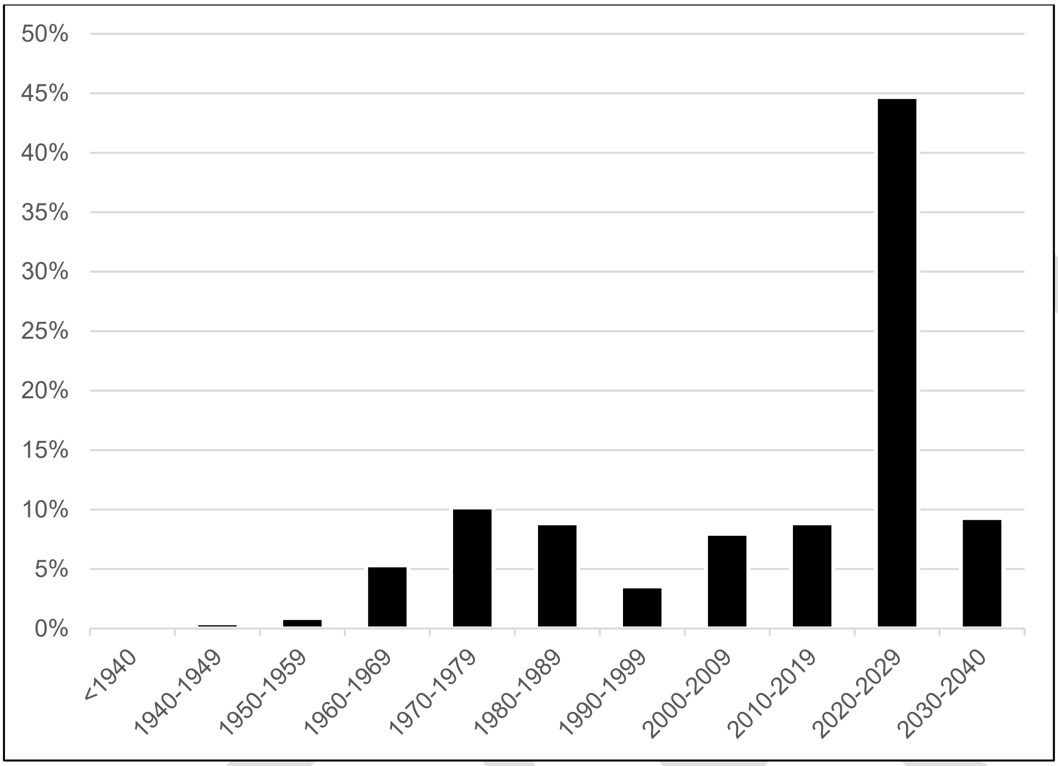


Figure 5-7 Distribution of sites according to their year of commissioning

5.3.3.3 Storage duration

Review of existing international PHES schemes larger than 1000 MW, from the data summarised above, found of the 25 schemes with published data for capacity and storage, the storage duration varied from 4 to 28 hours with an average of 11.6 hours.

GHD[291] reviewed publicly announced PHES projects in Australia. The scheme capacity varies widely based on the site and energy market limitations, with government projects typically larger than private developments. The minimum storage duration of existing and proposed schemes in Australia (excluding mine or quarry repurposing) is 8 hours with most government-implemented schemes being 24 hours or greater. For comparison, the NSW Government Long Term Energy Service Agreement (LTESA) for Long Duration Storage is targeting a storage duration of at least 8 hours, with a preference for greater than 12 hours.

With the significant improvement in battery technology and costs for short duration storage, future use of PHES schemes will likely be different to past applications. CSIRO [292] modelled levelised cost of storage (LCOS) for a range of technologies and concluded that “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”. BESS was also lower cost than PHES for 8-hour storage in the long term.

While some 8-hour PHES schemes may be commercially competitive, the real value of PHES is in long duration storage. For example, Snowy 2.0 will provide 85% of NEM energy storage (350 GWh) at ten times lower capital cost ($34/kWh[293]) than equivalent BESS and with five times longer lifetime.

[291] GHD (2025) AEMO Pumped Hydro Energy Storage Parameter Review
[292] CSIRO (2023) Renewable Energy Storage Roadmap
[293] SnowyHydro (2023) Media Release: **SECURING THE FUTURE OF CRITICAL ENERGY TRANSFORMATION PROJECTS - Snowy Hydro**

There is a clear trend that medium to long duration storage has been the typical use for PHES and that longer duration storage is anticipated to become more important as baseload is retired. For this reason, this study has included 10, 24 and 48 hour duration storage consistent with previous ISP development and has also included a further category for 160 hour storage. This very long storage duration takes advantage of a key aspect of PHES that duration can be extended (increasing MWh stored) by only increasing the volume of water stored, typically by increasing the size of the two dams, while all other costs remain relatively the same for the same installed power output (MW).

5.3.3.4 Availability of Water

Hydrology is not a significant constraint to off-river PHES, neither for initial filling, which can be achieved by water purchase, nor replacement of evaporation nor seepage losses. Although, this is sometimes perceived as a reason why PHES cannot be successful in Australia, or at least in certain regions.

Typical initial fill water requirement for PHES in Australia is approximately 0.8 GL per GWh[294]. Thus a 1000MW for 12 hour PHES (12 GWh) would require around 10 GL for initial fill. This initial fill is then cycled for many decades with only modest ongoing top up required. For comparison, the Australian Bureau of Statistics found that Australia used 13,500 GL of water in 2020-21 for irrigation urban and industrial uses. Noting that development of pumped hydro will be spread over 10-20 years, the small additional annual water requirement to fill PHES schemes can easily be sourced for this critical infrastructure.

The evaporative loss from a typical 1000MW PHES with no rainfall inflows is in the order of 1-2 GL/year. Evaporation suppressors and reservoir liners can be used to reduce evaporation and seepage losses further. A 1000 MW coal fired power plant can use up to 2.5GL of water per year, mostly for cooling[295]. As renewables and PHES replace coal, there should be no significant net change in water usage for energy supply assuming the water consumption is transferrable. Hence, water scarcity in Australia should not be seen as a reason to not develop pumped hydro.

5.3.3.5 Summary of changes

The key change since 2024 is a reduction in the estimated construction cost for 10 hour storage from $5,000 – 9,000 per kilowatt to $3,300 per kilowatt. AEMO received extensive stakeholder feedback noting the high cost parameters in 2024 which were a significant increase since the 2023 GenCost report. The cost developed in this 2025 update were benchmarked against internal cost data, published estimates and international publications, and are considered representative of costs for PHES projects.

OPEX costs have also reduced from 2024. OPEX costs in this 2025 update are based on escalated costs from the Entura[296] 2018 study which used real data from numerous hydropower operators and is therefore considered a suitable reference.

5.3.4 Selected hypothetical project

The hypothetical projects for this study are based on the publicly announced information on PHES schemes in Australia. GHD identified 40 publicly announced schemes[297]. Of these (excluding two with insufficient data):

– Thirty three schemes had a generation duration in the order of 10 hours. These had an average installed capacity of 445 MW. These were typically private developments with modest sized schemes reflecting a market that is commercially suitable. The hypothetical project for this 10 hr duration is a 500MW scheme consistent with the publicly announced examples.
– Five schemes had a generation duration in the order of 24 hours, and the proposed installed capacity varied widely. It is assumed that these longer duration schemes will by government led and aim for relatively large capacity. A hypothetical project of 1000MW for 24 hours has been assumed.
– There were no publicly announced 48 hour schemes. GHD[298] estimated the maximum build capacity for PHES within the NEM and identified over seventy possible sites with 48 hours storage duration and an

[294] Blakers et al. (2025) Pumped hydro energy storage to support 100% renewable energy Progress in Energy 7 022004
[295] Moerk Water **Water use in fossil fuel power generation - Moerk Water**
[296] Entura (2018) Pumped Hydro Cost Modelling
[297] GHD (2025) AEMO Pumped Hydro Energy Storage Parameter Review
[298] GHD (2025) AEMO Pumped Hydro Energy Storage Parameter Review

average installed capacity over 3000 MW. Further studies are likely to significantly reduce both the number of sites and installed capacity as constraints to the maximum build are identified. The hypothetical project assumed an installed capacity of 1000MW for 48 hours.

– GHD[299] identified over twenty potential sites within the NEM where 160 hour storage could be constructed with an average installed capacity over 4000MW, again this is likely to be reduced by currently unidentified constraints. For this study a 2000MW for 160 hour hypothetical project has been adopted, similar to Snowy 2.0.

At these large scheme sizes, the values estimated in the following tables are relatively insensitive to the selection of installed capacity. Schemes of double the size would have similar statistics.

Table 5.8 Configuration and performance – Pumped hydroelectric storage

Item	Unit	10 hours	24 hours	48 hours	160 hours	Comment
Configuration						
Fixed speed reversible units		2x250MW	4x250MW	4x250MW	8x250MW	Single 250MW units are economic and can connect to the NEM.
Performance						
Power capacity (Gross)	MW	500	1000	1000	2000	
Plant net power output	MW	495	990	990	1980	1% transformer and BoP losses
Seasonal rating - Summer (Net)	MW	495	990	990	1980	
Seasonal rating - Not summer (Net)	MW	495	990	990	1980	
Minimum stable generation	%	25%	15%	15%	8%	Each unit can generate at 50% capacity
Energy capacity	MWh	4950	23,760	47,520	320,000	
Annual Performance						
Average planned maintenance	Days / year	5	5	5	5	Typical performance specification requires 98.5% availability
Equivalent forced outage rate	%	1	1	1	1	Typical performance specification requirement
Annual number of full cycles		360	180	90	25	Likely more frequent operation for partial cycles
Annual energy storage degradation over design life	%	<0.1%	<0.1%	<0.1%	<0.1%	Regular maintenance and refurbishment to ensure unit efficiency does not drop

Table 5.9 Technical parameters and project timeline – Pumped hydroelectric storage

Item	Unit	10 hours	24 hours	48 hours	160 hours	Comment
Technical parameters						
Ramp up rate	MW/min	400	400	400	400	Varies depending on starting condition and generator or pump mode. Assume spinning to full generation or reverse in 15-20 secs.
Ramp down rate	MW/min	400	400	400	400	
Auxiliary load	%	1	1	1	1	
Round trip efficiency	%	75-80%	75-80%	75-80%	75-80%	Optimal schemes will be near 80%

[299] GHD (2025) AEMO Pumped Hydro Energy Storage Parameter Review

Item	Unit	10 hours	24 hours	48 hours	160 hours	Comment
Project timeline						
Time for development	Years	4	4	4	4	Includes pre/feasibility, design, approvals etc. (assuming no delay in development approvals)
EPC programme	Years	4	4.5	5.5	6.5	
– Total lead time	Years	0.5	0.5	0.5	0.5	Time from NTP to mobilisation
– Construction time	Weeks (years)	182 (3.5)	208 (4.0)	260 (5.0)	312 (6.0)	Mobilisation to completion
Economic / Design life	Years	100	100	100	100	Typical project specification
Technical life (Operational life)	Years	100	100	100	100	

5.3.5 Development cost estimates

GHD[300] prepared parametric cost estimates for 174 identified possible PHES schemes across the NEM. The parametric estimates were based on unit cost factors based on in-house databases multiplied by quantities estimated for different scheme parameters such as volume of material in dams, volume of tunnel excavation, MW of installed capacity etc. These were used to estimate a construction cost for each scheme. The following costs were allowed for:

- Upper dam/reservoir
- Upper intake
- Conveyance
- Powerhouse civil
- Powerhouse mechanical and electrical (including balance of plant)
- Lower intake
- Lower dam/reservoir
- Switchyard
- A percentage allowance for contingency, minor unpriced items, and indirect costs including mobilisation, site facilities and civil works, project management, insurance, EPC engineering and design.

The estimates were intended to represent EPC construction CAPEX. Exclusions from the cost estimates are:

- Water purchase and procurement
- Transmission because the NSP will consider connection costs.
- Owners' costs and financing

Figure 5-8 presents the average estimated CAPEX (expressed as $M/MW) for each NEM sub-region for each storage duration. There are minor differences, but a clear trend of increasing cost ($M/MW) for increasing duration, this is expected as the reservoirs must be larger to store more water. The costs ($M/MW) have been averaged for the entire NEM in Table 5.10. A comparison from published references is also included:

- The average power cost for 10 hour duration storage of $3.3M/MW is reasonably consistent with international benchmarking. For example, IHA[301] (2021) estimated USD2.2M/MW for 1000MW for 10 hour storage. Similarly, CSIRO GenCost 2023-2024[302] estimated approximately A$2.8M/MW for 8 to 12 hour PHES.
- The 2024 report[303] provided a range for EPC cost estimates of 42 and 48 hour PHES projects. It was noted that PHES project costs vary significantly depending upon various project attributes, and noted that favourable geotechnical conditions, shorter tunnels, above ground power houses, or existing suitable lower

[300] GHD (2025) AEMO Pumped Hydro Energy Storage Parameter Review
[301] International Hydropower Association (IHA) (2021) Pumped Storage Hydropower Capabilities and Costs
[302] CSIRO (2024) Gencost 2023-24 Final Report
[303] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)

reservoirs may have costs towards the lower end of the range. The GHD[304] study aimed to identify optimal PHES projects by screening out approximately 98% of sites in the ANU global atlas and these should be assumed to be at this lower end of the 2024 cost range. The average cost identified in this study is consistent with the lower end of the 2024[305] cost estimates which aligns with the intent of reporting optimal schemes in this study.

– The only known data point for a 160 hour PHES is Snowy 2.0. A Snowy Hydro media release[306] noted a construction cost of $12B for a 2,200MW scheme, or $5.45 M/MW. This is considerably lower than the average estimate in this study, highlighting that there may be more schemes that adopt two existing reservoirs and can be developed at a lower cost than the estimates provided in this study. At the time of publishing this revision, SnowyHydro had published a new media release stating that a 2025 cost review is underway. This may push the costing closer to the value adopted in this study.

Table 5.10 Average PHES power costs comparison

Duration	Average power cost $M/MW	Comparison ($M/MW)
10	3.30	3.3 (IHA 2021)
24	4.08	4.0 – 6.5[307]
48	4.85	5.0 – 7.5[308]
160	8.29	5.45[309]

Some of the publicly listed projects identified by GHD[310] in 2025 have published cost estimates. These were escalated from the date of publishing to reflect 2025 costs using the ABS cost index 3109 – Other heavy civil engineering construction Australia[311]. For the schemes with 8-12 hours storage duration, the average power cost was $2.6 M/MW, somewhat below the values estimated in this study.

The basis of the publicly announced estimates is rarely published. Noting that many of the public cost estimates were issued with environmental approvals documentation, they can be expected to reflect project costs with low contingency and no owners or land development costs. Published estimates for government projects are typically higher and may be more inclusive of the full development costs. Noting this uncertainty, the publicly announced cost estimates were not included in the cost factors.

[304] GHD (2025) AEMO Pumped Hydro Energy Storage Parameter Review
[305] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)
[306] SnowyHydro (2023) Media Release: **SECURING THE FUTURE OF CRITICAL ENERGY TRANSFORMATION PROJECTS - Snowy Hydro**
[307] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)
[308] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)
[309] SnowyHydro (2023) Media Release: **SECURING THE FUTURE OF CRITICAL ENERGY TRANSFORMATION PROJECTS - Snowy Hydro**
[310] GHD (2025) AEMO Pumped Hydro Energy Storage Parameter Review
[311] Australian Bureau of Statistics, Producer Price Indexes, Australia June 2025 - Output of Heavy and civil engineering construction prices, quarterly percentage change and index

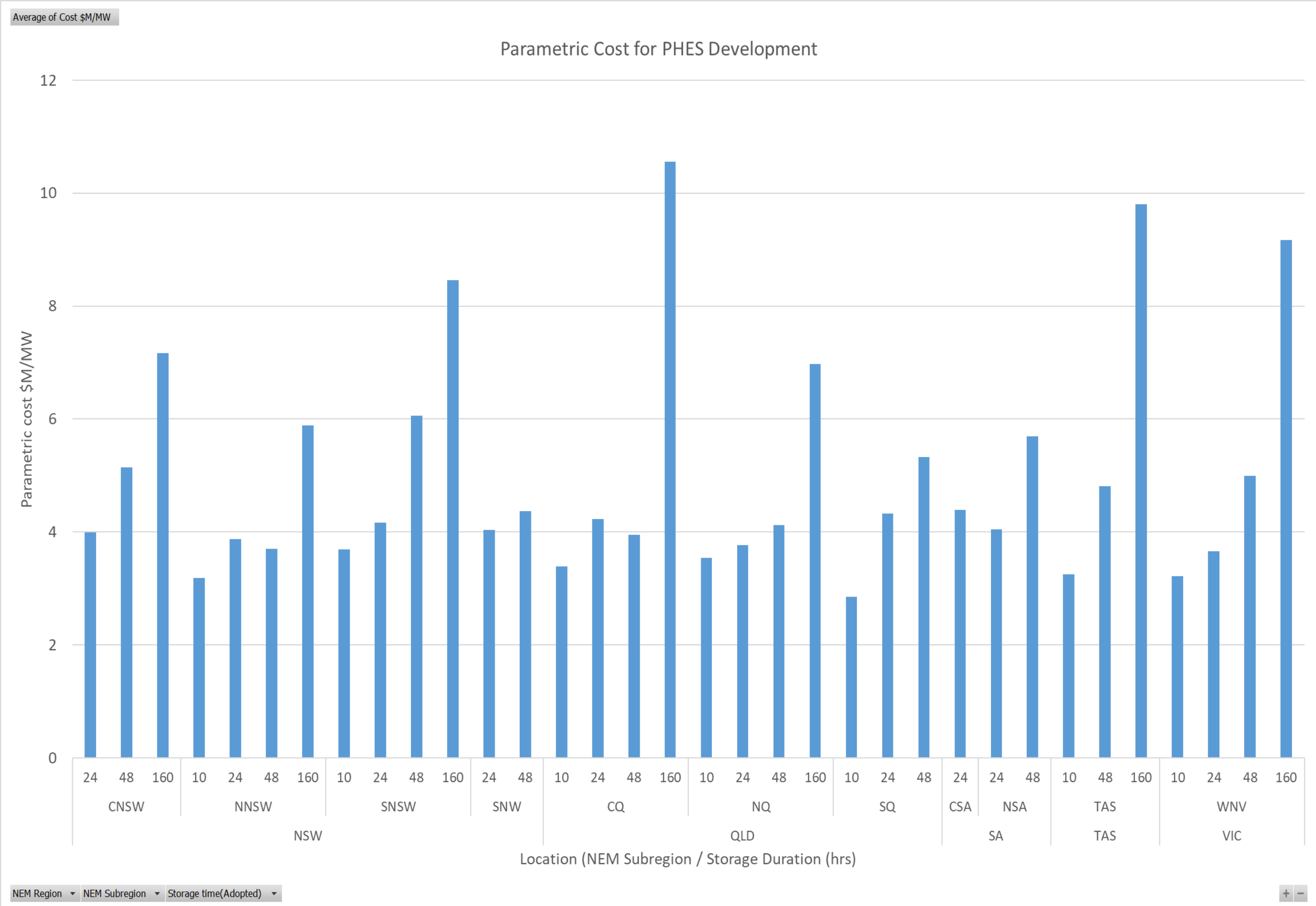


Figure 5-8 PHES relative power cost ($/MW) by sub-region

Table 5.11 Development cost estimates – Pumped hydroelectric storage

Item	Unit	500 MW x 10 hours storage	1,000 MW x 24 hours storage	1,000 MW x 48 hours storage	2,000 MW x 160 hours storage	Comment
CAPEX construction (with dedicated grid connection)						
Relative cost – Power and storage component	$/kW (Gross)	3,300	4,080	4,850	8,290	No additional storage cost ($/kWh) to be added
Total EPC cost	$	1,650,000,000	4,080,000,000	4,850,000,000	16,580,000,000	
– Equipment cost	$	410,000,000	1,020,000,000	1,210,000,000	4,150,000,000	25% of total
– Construction cost	$	1,238,000,000	3,060,000,000	3,638,000,000	12,435,000,000	75% of total
Other costs						
Cost of land and development	$	100,000,000	240,000,000	290,000,000	990,000,000	

5.3.6 O&M cost estimates

Entura[312] estimated O&M costs for PHES based on several US and Australian reviews, validated against Hydro Tasmania's portfolio data. They concluded that variable O&M is not meaningful for hydropower projects, as it does not take into account the most damaging aspects of operation. As such, fixed O&M costs only should be

[312] Entura (2018) Pumped Hydro Cost Modelling

used, and recommended a single value of $16,000/MW/yr for stations with installed capacity greater than 100MW and less than 50 years old. This has been escalated to 2025 values using ABS cost index data[313] (index 3109).

The following table provides fixed and total annual O&M cost estimates for the defined pumped hydroelectric storage projects.

Table 5.12 O&M cost estimates – Pumped hydroelectric storage

Item	Unit	500 MW x 10 hours storage	1,000 MW x 24 hours storage	1,000 MW x 48 hours storage	2,000 MW x 160 hours storage	Comment
Fixed O&M cost	$/MW/year (Net)	20,000	22,500	25,000	30,000	Escalated from Entura[314] (2018)
Variable O&M cost	$/MWh (Net)	Nil	Nil	Nil	Nil	Included in fixed component
Total annual O&M cost	$	10,000,000	22,500,000	25,000,000	60,000,000	Indicative annual average cost over operating life

5.3.7 Retirement cost estimates

The retirement of PHES will require decommissioning of waterways and plant before dismantling of the powerhouse can proceed. Dewatering of the system needs to be undertaken so that the waterways can be permanently isolated at the intakes and then the main plant in the powerhouse decommissioned.

On completion of removal of underground plant, the cavern can be used for disposal of inert material as a result of surface demolition and rehabilitation. Upon completion of disposal and rehabilitation works the access portals and shafts can be sealed against human access.

The high-level process for retirement of PHES, as outlined in Appendix C, will include:

– Isolation of power waterways.
– Dewatering of power waterways.
– Decommissioning of plant within powerhouse.
– Plugging and sealing intake structures. Removal of intake gates.
– Dismantling and removal of non-embedded components of main plant and balance of plant in powerhouse and transformer caverns.
– Dismantling and removal of surface plant including transmission lines and switchyard in parallel with underground works.
– Removal of foundations and complete rehabilitation of surface works.
– Disposal of non-recyclable inert materials within underground cavern.
– Plugging and sealing of shafts and tunnels with reinforced mass concrete plugs.

Table 5.13 Retirement cost estimates – Pumped hydroelectric storage

Item	Unit	500 MW x 10 hours storage	1,000 MW x 24 hours storage	1,000 MW x 48 hours storage	2,000 MW x 160 hours storage
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	9,000	6,500	6,500	6,500
Disposal costs	$/MW (Net)	4,000	2,000	2,000	2,000
Recycling costs	$/MW (Net)	(2,500)	(1,500)	(1,500)	(1,500)
Total retirement costs	$/MW (Net)	10,500	7,000	7,000	7,000

[313] Australian Bureau of Statistics, Producer Price Indexes, Australia June 2025 - Output of Heavy and civil engineering construction prices, quarterly percentage change and index
[314] Entura (2018) Pumped Hydro Cost Modelling

6. Battery energy storage system

6.1 Overview

Historically, Australia's energy storage infrastructure has been dominated by pumped hydro energy storage, however recent years have seen a dramatic increase in development and deployment of utility scale battery energy storage systems and a long pipeline of proposed projects.

At the end of 2024, Australia's energy storage capacity was in the order of 3 GW, inclusive of pumped hydro, VPPs and battery energy storage systems (BESS)[315]. While projections vary, it is broadly consistent across industry views that this figure will increase dramatically over the coming years, with a projection by BloombergNEF placing a potential 8-fold increase in utility scale BESS systems between 2024 and 2035 from 2.3 GW to 18 GW[316]. AEMO's 2024 ISP projects a requirement for energy storage (across PHES and BESS) in the order of 49 GW by 2050 under the *Step change* scenario, again emphasizing the strong uptake in energy storage projects required in the coming decades to meet projected energy and system demands.

The build-up of this future pipeline of energy storage infrastructure is expected to include BESS ranging from 'shallow' (less than 4 hours) to 'medium' (4-8 hours) depth, as well as substantial amounts of deep storage that focuses on pumped hydro energy storage.

The following sections outline the typical options, recent trends, technical parameters, and cost parameters for each of the nominated battery technologies.

Technologies within this section include:

- Large-scale lithium-ion battery storage
- Residential battery storage
- Vanadium redox flow battery (VRFB) energy storage
- An overview of alternative/emerging chemistries

6.2 Large-scale lithium-ion battery storage

6.2.1 Overview

Large scale lithium-ion battery technology continues to be deployed for utility scale[317] facilities throughout Australia and the capacity base is increasing rapidly. GHD is aware of at least 30 large scale BESS facilities that have been constructed since the industry emerged in 2017 and across Australia hundreds of BESS facilities are now in various stages of announcement, development or construction. With battery design life for the majority of OEM products at up to 20 years[318], it is expected that there will be a significant volume of battery storage capacity that will be retired from 2035 onwards.

The modular nature of a BESS enables it to be sized separately for both power and energy requirements to meet varied project requirements. A typical standalone large-scale BESS consists of several major components including:

- Battery system.
- Battery management system.
- Power conversion stations (bi-directional inverters/converters).
- Step-up transformer(s).
- Power plant control system.
- Switch room / switchyard.

[315] **Battery Storage: Australia's current climate**
[316] **BNEF: Australia to reach 18GW of large-scale BESS by 2035 - Energy-Storage.News**
[317] **https://www.energysage.com/business-solutions/utility-scale-battery-storage/**
[318] **Battery Energy Storage System (BESS).pdf**

– Operations and balance of plant equipment.

6.2.2 Typical options

"Lithium-ion" battery technology is a term which covers numerous sub-chemistries which in the Australian large scale BESS market have typically included:

– Lithium Nickel-manganese-cobalt oxide (NMC).
– Lithium nickel-cobalt-aluminium oxide (NCA).
– Lithium iron phosphate (LFP).

As the market has matured, LFP technology has shown commercial and safety advantages particularly in relation to reduced propensity for thermal runaway, and accordingly the LFP sub-chemistry is currently the preferred technology for most utility scale applications.

6.2.3 Recent trends

For storage duration, early BESS deployments favoured battery durations of 1 hour or less. Currently BESS facilities in Australia are typically at 2-4 hours duration[319] and developments are now considering up to 8 hours duration[320]. This is largely driven by reductions in battery prices over time and the market which batteries operate in rewarding power price arbitrage. Capacity of recent developments have been in the hundreds of MW, including the Waratah Super Battery (850MW/1650MWh), AGL Liddell BESS (500MW/1000MWh), Stanwell (300MW/1200MWh), and Collie (first phase 219MW/877MWh).[321]

Increasingly, BESS are being proposed to be co-located with other generation facilities, including solar PV and onshore wind. The option of DC coupling has potential to reduce duplication of inverter equipment with potential to further reduce land area requirements and associated cabling which could therefore reduce overall retirement costs. GHD also notes that grid forming BESS technology which allows the provision of inertia and system strength support is becoming far more prevalent, however, this capability does not significantly change equipment requirements and therefore is not expected to have significant impact on BESS costs.

With ongoing technology development and improvements by manufacturers, the latest products available on the market are boasting increased energy density, improved efficiency and degradation parameters, and improved warranty and performance guarantee coverage. While earlier warranty offerings from suppliers were limited at 10-15 years of coverage, current offerings are commonly seen up to 20 years, with some pushing even to 25 years of coverage (based on GHD's recent experience in the market), providing more certainty to developers and investors.

At the same time, increased awareness and interest from approving authorities and associated stakeholders (such as local fire authorities and emergency services) is resulting additional focus on fire (e.g. thermal runaway) risk, noise issues, and suitable management of site related risks (e.g. access to water, access and egress for emergency vehicles, contaminated fire water runoff containment, and so on). These considerations are increasingly incorporated into BESS facility designs from early in the project lifecycle to feed into site selection, approvals processes, stakeholder and community consultation, and tendering and development activities.

The aggregate effect of these advancements is that BESS projects in development are achieving higher capacities in smaller footprints, while seeing reduced capital costs, increased certainty in long term servicing and warranty coverage, and improving characteristics around fire safety and suppression systems. In general, total costs for Li-ion BESS systems in the 1-8 hour duration range have been seen to decrease in the order of 10-15% against the 2024 benchmarks.

An additional trend that has been seen to continue is the tendency for BESS projects to be delivered in a split contract model, moving away from an initial industry preference for EPC style delivery. With battery suppliers being in high demand, there has been reducing appetite from OEMs to take on additional scope and risk

[319] **https://www.pv-magazine.com/2024/10/24/australia-has-7-8-gw-of-utility-scale-batteries-under-construction/**
[320] **https://au.rwe.com/projects/limondale-bess/**
[321] **https://www.pv-magazine.com/2024/10/24/australia-has-7-8-gw-of-utility-scale-batteries-under-construction/**

associated with balance of plant and overall system integration, requiring additional effort from developers and owners to implement a multi-contract model to execute projects.

Regarding retirement, it is likely that all of the current lithium-ion battery chemistries will be dealt with in a similar fashion, either needing assessment of individual modules or cells for potential repurposing or look to processing or disposal. Currently the lithium-ion recycling industry is emerging with ambition to reduce costs and improve material recovery. It is envisaged that processes to recycle lithium batteries will improve significantly over coming years due to the size of the opportunity[322] as will the ability for industry to handle larger volumes of batteries. Combined, it is expected that battery recycling costs should improve over current cost estimates.

Continuing these trends is likely to marginally reduce retirement costs particularly associated with balance of plant equipment and rehabilitation. As the BESS industry is in relative infancy, it is expected that other developing battery chemistries, favouring cheaper and more recyclable materials, might also begin to encroach on the current lithium dominated market. However, all emerging chemistries would still be expected to require costs for recycling and / or disposal.

In terms of retirement costs, increasing the storage duration will increase the volume of batteries requiring recycling and / or disposal as well as balance of plant requirements (containers, HVAC, controllers etc.) for each MW of installed capacity. However, it would be expected that the unit cost (per MWh) for retirement would decrease with increasing economies of scale.

6.2.3.1 Summary of changes

Since the 2024 report, the main difference in large-scale lithium-ion BESS projects is a continuing downward trend on capital costs, with overall market costs being seen to be 10-15% lower than last years equivalents. Costs for the battery costs specifically have reduced by more than this in some situations, however, increases in balance of plant and ancillary equipment costs have counteracted this movement to a minor degree. These changes also have the effect of increasing the installation cost portion of the total cost in comparison to the split presented in the 2024 report.

The source of cost reductions for lithium-ion BESS in recent years is due to a combination of movements in lithium carbonate commodity prices (which spiked in 2022-23 and have recently recovered to prior levels) and ongoing incremental technology and supply chain improvements. A high degree of competition in the global lithium-ion equipment provider market is continuing to deliver products with improved energy density and associated cost advantages which is further supporting this downward trend. Increased domestic deployment also contributes to learning rates within the industry and reduces risk premiums, both of which contribute further to cost reductions for delivered projects.

6.2.4 Selected hypothetical project

The selected hypothetical project for a utility scale BESS is presented in Table 6.1.

Table 6.1 Configuration and performance – Large-scale lithium-ion BESS

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Configuration						
Technology		Li-ion (LFP)	Li-ion (LFP)	Li-ion (LFP)	Li-ion (LFP)	
Performance						
Power capacity (Gross)	MW	200	200	200	200	
Energy capacity	MWh	200	400	800	1600	
Auxiliary power consumption (operating)	kW	1700	1900	2400	3500	Weather dependent
Auxiliary power consumption (standby)	kW	300	600	1200	2400	Weather dependent

[322] **Lithium-Ion Battery Recycling Market Size, Forecast 2025-2034**

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Auxiliary load – operating	%	0.85%	0.95%	1.20%	1.75%	Based on auxiliary power consumption (operating)
Auxiliary load - standby	%	0.15%	0.30%	0.60%	1.20%	Based on standby auxiliary power above
Power capacity (Net)	MW	198.3	198.1	197.6	196.5	Based on operating auxiliary load.
Seasonal rating – Summer (Net)	MW	198.3	198.1	197.6	196.5	Rating for temperatures up to 40 degrees C, above which inverter derating will apply.
Seasonal rating – not summer (Net)	MW	198.3	198.1	197.6	196.5	
Annual Performance						
Average planned maintenance	Days / year					Included in EFOR
Equivalent forced outage rate	%	1-2%	1-2%	1-2%	1-2%	
Annual number of full cycles		365	365	365	365	
Annual energy storage degradation over design life	%	1.60%	1.60%	1.60%	1.60%	Typical based on cycling rate
Annual RTE degradation over design life	%	0.25%	0.25%	0.25%	0.25%	Reducing from 85% to 80% over 20 year design life.

Table 6.2 Technical parameters and project timeline – Large-scale lithium-ion BESS

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Technical parameters						
Ramp up rate	MW/min	10,000+	10,000+	10,000+	10,000+	Limited by power capacity.
Ramp down rate	MW/min	10,000+	10,000+	10,000+	10,000+	
Round trip efficiency (Beginning of life)	%	85	85	85	85	
Charge efficiency (Beginning of life)	%	92.2	92.2	92.2	92.2	Based on even split of RTE losses for charging and discharging.
Discharge efficiency (Beginning of life)	%	92.2	92.2	92.2	92.2	As above.
Allowable maximum state of charge	%	100	100	100	100	Assumes that BESS specification dictates requirement for usable energy storage capacity.
Allowable minimum state of charge	%	0	0	0	0	As above. It is noted that BESS performance specifications and warranties often include operational limitations at the extremes of state of charge.
Maximum number of cycles		7300	7300	7300	7300	Based on a 20 year design life and typical operational profile of one full cycle per day. Consistent with typical warranty offerings up to 20 years. Some OEM's are offering
Depth of discharge	%	100	100	100	100	As above, assumes BESS specification dictates requirement for usable energy storage capacity.

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Project timeline						
Time for development	Years	1-2	1-2	1-2	1-2	
EPC programme	Years	1.6	1.8	2.0	2.2	
– Total lead time	Years	1.5	1.5	1.5	1.5	
– Construction time	Weeks	44	52	60	68	
Economic life (Design life)	Years	20	20	20	20	
Technical life (Operational life)	Years	20	20	20	20	

6.2.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined large-scale lithium-ion BESS projects.

Table 6.3 Development cost estimates – Large-scale lithium-ion BESS

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
CAPEX – cost for 200 MW BESS (with dedicated grid connection)						
Relative cost – Power component	$/kW (Gross)	410	410	410	410	Applicable to the power component of the facility (i.e. the MW rating of the facility). Is additive with energy component.
Relative cost – Energy component	$/kWh	310	290	265	245	Applicable to the energy component of the facility (i.e. the MWh rating of the facility). Is additive with power component.
Total cost	$	144,000,000	198,000,000	294,000,000	474,000,000	Total cost is the addition of the power component and energy component.
Equipment cost	$	108,000,000	149,000,000	221,000,000	356,000,000	Calculated as 75% of total project cost.
Installation cost	$	36,000,000	49,500,000	73,500,000	119,000,000	Calculated as 25% of total project cost.
CAPEX – cost for 200 MW BESS (co-located with large renewable installation)						
Relative cost – Power component	$/kW	369	369	369	369	As above. Assumed at 90% of cost of standalone system due to shared electrical connection infrastructure
Relative cost – Energy component	$/kWh	310	290	265	245	As above.
Total cost	$	136,000,000	190,000,000	286,000,000	466,000,000	As above.
Equipment cost	$	102,000,000	142,000,000	214,000,000	349,000,000	As above.
– Installation cost	$	34,000,000	47,500,000	71,500,000	117,000,000	As above.
Other costs						

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Cost of land and development	$	10,000,000	10,000,000	10,000,000	10,000,000	Allowance to account primarily for project development costs.

6.2.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined large-scale lithium-ion BESS projects.

Table 6.4 O&M cost estimates – Large-scale lithium-ion BESS

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Fixed O&M cost	$/MW/year (Net)	6,000	10,000	16,000	24,000	
Variable O&M cost	$/MWh (Net)	-	-	-	-	Included in Fixed O&M cost.
Total annual O&M cost (excluding extended warranties)	$k	1,200	2,000	3,200	4,800	
Extended warranty (20- year battery life)	$/MW (Net)	2,500	5,000	10,000	20,000	
Extended warranty cost per year	$k	500	1,000	2,000	4,000	
Total annual O&M Cost (Fixed O&M + extended warranties)	$k	1,700	3,000	5,200	8,800	

6.2.7 Retirement cost estimates

Retirement costs for the defined large-scale lithium-ion BESS projects are outlined in the table below. Refer to Appendix C for further detail and assumptions related to retirement costs.

Table 6.5 Retirement cost estimates – Large-scale lithium-ion BESS

Item	Unit	1 hour	2 hours	4 hours	8 hours
Decommissioning, demolition & rehabilitation costs	$/MW (Gross)	28,000	41,000	76,000	128,000
Disposal costs	$/MW (Gross)	7,000	14,000	27,000	55,000
Recycling costs	$/MW (Gross)	(4,000)	(6,000)	(9,000)	(17,000)
Total retirement costs	$/MW (Gross)	**31,000**	**49,000**	**94,000**	**166,000**

6.3 Residential battery storage

6.3.1 Overview

Residential battery energy storage systems (RBESS) are a growing sector in Australia, prompted by ongoing uptake of residential rooftop solar PV systems, decreasing battery system costs, increasing consumer electricity prices, and recent government incentives. RBESS systems are generally installed in conjunction with rooftop solar PV systems, intended to capture excess electricity produced during daylight hours from the PV system and storing it for consumption during evening peak power consumption hours and overnight.

RBESS systems are most commonly used to offset increasing consumer (i.e. residential) electricity tariffs and can enable increased uptake of solar PV for a given household electricity demand. They may also be used in some instances to reduce grid reliance, provide backup power for off-grid or fringe-of-grid applications, or used by aggregation providers (e.g. retailers) to participate in VPP programs.

6.3.2 Typical options

Given that RBESS systems are installed in a residential end-user environment, typical offerings represent a product more akin to a consumer electronics product than to an industrial electrical installation (which is more common in utility scale energy storage systems). Accordingly, systems are typically provided with all required software (e.g. battery management system (BMS) and often real-time monitoring software) and hardware (e.g. battery cells and enclosed battery cabinet, and user interface panel).

Systems may be supplied either in an AC-connected configuration (requiring an inverter to connect the DC battery system to an AC power connection point) or in a DC-connected hybrid arrangement installed alongside a DC solar PV system. For the latter, savings may be realised by having only a single inverter/converter shared between the PV and RBESS system, and fewer energy conversion losses will be experienced in storing excess solar energy in the BESS.

The RBESS market is heavily dominated by lithium ion (Li-ion) products, with both NMC and LFP chemistries being used in typical applications. LFP chemistry is tending to be preferred in current iterations of products on the market due to benefits in stability and safety.

6.3.3 Recent trends

Consistent with trends in the utility scale BESS market, prices over the last 12+ months have tended strongly downward, resulting in RBESS system prices in the order of 10-20% lower than was available 12 months ago.

Other continuing trends in the RBESS market are associated with smart energy management systems, integration with VPP offerings from major retailers, and prevalence of government rebates for RBESS systems that reduce the effective price of systems borne by consumers. It is noted that the typical prices presented below do not consider any government rebates.

6.3.3.1 Summary of changes

The primary change since the 2024 version of this Report and dataset is related to ongoing reduction in capital cost, which is consistent with the trend seen for utility scale lithium-ion projects. Total costs in the market are seen to have decreased by 15-20% compared to the year-ago equivalent pricing.

6.3.4 Selected hypothetical project

The selected hypothetical project for a RBESS is presented in Table 6.6. This size of project is within the typical range deployed into household systems in Australia, with common installations ranging from 5-15 kWh.

Table 6.6 Configuration and performance – Residential BESS

Item	Unit	2 hours	Comment
Configuration			
Technology		Li-ion	LFP technology assumed
Performance			
Power capacity (Gross)	kW	5	
Energy capacity	kWh	10	
Auxiliary power consumption (operating)	W	50	
Auxiliary load	%	1	Based on auxiliary power consumption (operating)
Power capacity (Net)	kW	4.95	
Seasonal rating – Summer (Net)	kW	4.95	
Seasonal rating – Not summer (Net)	kW	4.95	

Item	Unit	2 hours	Comment
Annual performance			
Equivalent forced outage rate	%	2-3%	Based on 5-10 days per year. In practice, outages (mainly due to equipment faults) are likely to be infrequent but longer to return to service due to call-out requirement.
Annual number of full cycles		365	Assumed daily cycling
Annual energy storage degradation over design life	%	1.6%	
Annual RTE degradation over design life	%	0.25%	

Table 6.7 Technical parameters and project timeline – Residential BESS

Item	Unit	2 hours	Comment
Technical parameters			
Ramp up rate	kW / min	10,000+	Limited based on power capacity.
Ramp down rate	kW / min	10,000+	
Round trip efficiency (Beginning of life)	%	85	
Charge efficiency (Beginning of life)	%	92.2	
Discharge efficiency (Beginning of life)	%	92.2	
Allowable maximum state of charge	%	100	
Allowable minimum state of charge	%	0	Industry trend is for systems to allow full depth of discharge, however some warranty limitations may be imposed at high and low state of charge (i.e. <20% state of charge), however this is warranty and supplier specific.
Maximum number of cycles		3650	Technically capable of more than 3650 cycles, but typical warranties provide coverage for 10 years of daily cycling.
Depth of discharge	%	100	As noted above.
Project timeline			
Time for development (ordering and installation)	Days	60	Likely to be less in majority of instances given in-country availability of equipment (i.e. 30 days). Additional 30 days allowed to account for equipment ordering.
Economic life (Design life)	Years	10	Warranties typically provide coverage for 10 years.
Technical life (Operational life)	Years	10-15	Equipment likely to be operational outside of typical warranty life of 10 years, however maintenance and repair cost and complexity will increase.

6.3.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined residential BESS.

Table 6.8 Development cost estimates – Residential BESS

Item	Unit	2 hours	Comment
Installation costs for 5 kW RBESS (AC-coupled, not including new PV inverter)			
Relative cost – Power component	$ / kW		Costs provided as total cost in $/kW for a 5 kW, 10 kWh system, including inverter and installation.
Relative cost – Energy component	$ / kWh		
Total EPC cost	$	11000	Exclusive of any government subsidies.

Item	Unit	2 hours	Comment
– Equipment cost	$	8250	
– Installation cost	$	2750	

6.3.6 O&M cost estimates

The following table provides annual O&M cost estimates for the defined residential BESS project, noting that RBESS maintenance activities are assumed to be covered by product warranty and therefore do not incur further maintenance costs.

Table 6.9 O&M cost estimates – Residential BESS

Item	Unit	2 hours	Comment
Total annual O&M cost	$	-	Maintenance or equipment faults assumed to be covered by product warranty.

6.3.7 Retirement cost estimates

Residential battery systems require appropriate disposal at end of life, similar to disposal of household batteries and electronic waste which is unsuitable for landfill or general waste disposal. The size of residential battery systems mean that specialist providers are likely to be required to remove, transport, dismantle, and appropriately recycle the battery components.

The cost for such a service is indicated to be in the order of $11/kg[323], with $3/kg for handling and $8/kg for battery recycling charges. The weight of a 10-kWh household battery varies by manufacturer but is in the order of 100-150 kg. Assuming the mid-point in weight, this results in the disposal and recycling costs presented in Table 6.10, presented on a $/kW basis for a 5 kW / 10 kWh system.

Table 6.10 Retirement cost estimates – Residential BESS

Item	Unit	2 hours	Comment
Decommissioning, demolition & rehabilitation costs	$/kW	-	Included in disposal costs
Disposal costs	$/kW	75	Costs required for handling and transportation
Recycling costs	$/kW	200	Recycling fee
Total retirement costs	$/kW	275	

6.4 Vanadium redox flow battery storage

6.4.1 Overview

VRFB energy storage systems utilise a vanadium-based redox reaction to store energy in liquid electrolytes. Vanadium flow batteries represent a ‘pure’ flow battery technology, where the power capacity of the system (kW or MW) and energy capacity of the system (kWh or MWh) can be completely decoupled, theoretically enabling easier scaling of the energy component by increasing installed capacity of tanks and electrolyte. This differs from some flow battery chemistries (such as zinc bromine and iron flow) which involve material plating or membrane deposition, meaning that energy and power cannot be as easily de-coupled.

The main systems in a VRFB include:

– A mechanical process system that includes two or more large volumes of vanadium electrolyte, along with associated pipework, pumps, process equipment, and instrumentation
– An array of stacks through which the electrolytes flow, separated by a membrane

[323] **Pricing for Lithium Battery Recycling Service - Battery Rescue**

– An electrical system that captures the electrical energy from the flow of electrolyte, along with a power conversion system that provides usable power output or converts the incoming power to a usable form (for discharge and charge operating modes respectively)
– An auxiliary electrical system that may be integrated or decoupled from the main electrical system, providing power for ancillary systems such as heat exchangers, cooling and ventilation, and controls equipment

6.4.2 Typical options

While decoupling of energy and power is a key advantage of VRFB technology, the trend in technology suppliers is to develop their products in typical 'blocks' of capacity, allowing them to produce a standard product at scale rather than to develop custom designs for each project or application. In the current market, typical offerings from manufacturers come in form factors ranging from 4-12 hours, often in a modular configuration that involves addition or extension of containers to increase depth of storage. In some instances, increasing in duration from 4 to 12 hours is achieved by reducing the number of power modules (i.e. stacks and associated power electronics components) installed in the containers, thereby maintaining a consistent energy capacity in kWh while reducing the power capacity in kW, resulting in increased 'hours' of storage.

Interest from the market for a genuinely de-coupled and de-containerised solution may prompt additional focus from VRFB technology suppliers in providing solutions in excess of 12 hours, however these products are not readily available and would require a degree of product development and evolution in order to match the technology readiness level of existing containerised products.

6.4.3 Recent trends

In the Australian context, strong interest persists in VRFB technology and project opportunities, however few projects have proceeded past studies and feasibility assessments into delivery. The Yadlamalka Energy project[324] represents one of the larger VRFB implementations in Australia at a scale of 2 MW / 8 MWh (co-located with 6 MW of solar PV), which has been in construction and commissioning over the last 2-3 years.

In 2025, the Western Australian Government announced a $150 million commitment towards the development of a locally manufactured Vanadium Battery Energy Storage System (VBESS) in Kalgoorlie[325], with a target size of 50 MW and 10 hours of storage. This project would represent the largest VRFB in Australia by a large margin, however the project is still in early stages, with expressions of interest for the opportunity scheduled to open in the second half of 2025[326].

Globally, China is the most active in deployment of large-scale VRFB projects, such as a 200 MW / 1 GWh project that was reported to be nearing completion in 2025[327], a 175 MW / 700 MWh project by Rongke Power in 2024[328], and a 100 MW / 400 MWh project (which is stated to be the first phase of a total 800 MWh project) also by Rongke Power in 2022[329].

6.4.3.1 Summary of changes

The primary change between the 2024 version of this Report and dataset to the current document is the adjustment from 24 and 48-hour storage depth to 8 and 12-hour storage depth, which was adopted to reflect the typically available vanadium flow battery products available on the market. While deeper storage duration is theoretically and technically possible, it requires more bespoke and site-specific engineering and development, which poses challenges to equipment suppliers who are targeting manufacturing consistency and economies of scale in production.

[324] https://yadlamalkaenergy.com/project/
[325] https://www.wa.gov.au/government/announcements/vanadium-battery-energy-storage-system-expression-of-interest
[326] https://www.wa.gov.au/government/announcements/vanadium-battery-energy-storage-system-expression-of-interest
[327] https://www.ess-news.com/2025/07/04/china-completes-worlds-largest-vanadium-flow-battery-plant/
[328] https://www.energy-storage.news/rongke-power-completes-grid-forming-175mw-700mwh-vanadium-flow-battery-in-china-worlds-largest/
[329] https://www.energy-storage.news/first-phase-of-800mwh-world-biggest-flow-battery-commissioned-in-china/

6.4.4 Selected hypothetical project

The selected hypothetical projects for utility scale implementation of a vanadium redox flow battery are as presented in Table 6.11. It is noted that the hypothetical projects have been adjusted from the 2024 report[330] (which were presented as 24- and 48-hour storage options) to what is presented below (8 and 12 hours of storage) to reflect readily available market offerings.

Table 6.11 Configuration and performance – Vanadium redox flow BESS

Item	Unit	8 hours	12 hours	Comment
Configuration				
Technology		Vanadium redox flow	Vanadium redox flow	
Performance				
Power capacity (Gross)	MW	200	200	
Energy capacity	MWh	1,600	2,400	
Auxiliary power consumption (operating)	MW	13.6	13.6	
Auxiliary power consumption (standby)	MW	6.8	6.8	It is noted that this is consumption for an 'active' standby mode, whereby electrolyte is kept circulating and the system can respond in <1000 ms. Long-term standby modes require greatly reduced auxiliary power, in the order of 5-10% of active standby levels.
Auxiliary load (operating)	%	6.8%	6.8%	Based on auxiliary power consumption (operating)
Auxiliary load (standby)	%	3.4%	3.4%	Based on standby auxiliary power above
Power capacity (Net)	MW	186.4	186.4	
Seasonal rating – Summer (Net)	MW	186.4	186.4	
Seasonal rating – not summer (Net)	MW	186.4	186.4	
Annual performance				
Average planned maintenance	Days / year			Included in EFOR
Equivalent forced outage rate	%	3-5	3-5	Availability figures seen in the market range from 95%-97% availability.
Annual number of full cycles		365	365	
Annual degradation over design life (energy)	% p.a.	0.5%	0.5%	
Annual degradation over design life (RTE)	% p.a.	0.1%	0.1%	

Table 6.12 Technical parameters and project timeline – Vanadium redox flow BESS

Item	Unit	8 hours	12 hours	Comment
Technical parameters				
Ramp up rate	MW/min	10,000+	10,000+	Response time to full power in <1000 ms.
Ramp down rate	MW/min	10,000+	10,000+	As above

[330] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)

Item	Unit	8 hours	12 hours	Comment
Round trip efficiency (Beginning of life)	%	70%	70%	Highly dependent on operating point, ambient conditions, and operating regime.
Charge efficiency (Beginning of life)	%	83.7%	83.7%	Assumed even split between charge and discharge contribution to RTE
Discharge efficiency (Beginning of life)	%	83.7%	83.7%	As above.
Allowable maximum state of charge	%	100	100	Some charge and discharge rate limitations may be imposed (OEM specific) at high and low charge levels (i.e. >90%, <10% state of charge).
Allowable minimum state of charge	%	0	0	As above.
Maximum number of cycles		>10,000	>10,000	
Depth of discharge	%	100	100	
Project timeline				
Time for development	Years	1.5-2	1.5-2	
EPC programme	Years	2	2	
– Total lead time	Years	1.5	1.5	Typical lead time from NTP to first delivery is in the order of 1 year. Lead time for transformers and switchgear can be in the order of 1.5 years.
– Construction time	Weeks	78	78	Construction of BOP assumed to commence 6 months after NTP
Economic life (Design life)	Years	25	25	
Technical life (Operational life)	Years	25	25	

6.4.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined vanadium redox flow BESS.

Table 6.13 Development cost estimates – Vanadium redox flow BESS

Item	Unit	8 hours	12 hours	Comment
CAPEX – cost for 200 MW BESS (with dedicated grid connection)				
Relative cost – Power component	$/kW	-	-	De-coupling power and energy components is not easily accomplished in the current market where products are packaged in a containerised solution with a fixed form factor. Accordingly, results are reported on a kWh basis only.
Relative cost – Energy component	$/kWh	910	815	
Total EPC cost	$	1,456,000,000	1,956	
– Equipment cost	$	1,092,000,000	1,467,000,000	Electrolyte counted as part of equipment cost
– Installation cost	$	364,000,000	489,000,000	
CAPEX – cost for 200 MW BESS (co-located with renewable installation)				
Relative cost – Power component	$/kW			
Relative cost – Energy component	$/kWh	865	774	Reduced by 5% to account for common infrastructure shared with renewables.
Total cost	$	1,383,000,000	1,858,000,000	

Item	Unit	8 hours	12 hours	Comment
– Equipment cost	$	1,037,000,000	1,394,000,000	
– Installation cost	$	346,000,000	465,000,000	
Other costs				
Cost of land and development	$	15,000,000	15,000,000	

6.4.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined vanadium redox flow BESS projects.

Table 6.14 O&M cost estimates – Vanadium redox flow BESS

Item	Unit	8 hours	12 hours	Comment
Fixed O&M cost	$/MW/year (Net)	145,600	195,600	O&M figures vary widely between OEMs, and limited operational data is available to validate vendor claims. Quoted figures range from 1-3% of CAPEX per year, depending on scope. Presented figures based on 2% CAPEX per year.
Variable O&M cost	$/MWh (Net)	-	-	Included in fixed O&M above.
Total annual O&M cost	$	29,100,000	39,100,000	

6.4.7 Retirement cost estimates

Retirement costs for the defined vanadium redox flow BESS projects are outlined in the table below.

Table 6.15 Retirement cost estimates – Vanadium redox flow BESS

Item	Unit	8 hours	12 hours	Comment
Decommissioning, demolition & rehabilitation costs	$/MW (Gross)	455,000	569,000	
Disposal costs	$/MW (Gross)	410,000	487,000	
Recycling costs	$/MW (Gross)	(3,003,000)	(4,415,000)	Large majority of recycling value (represented as negative recycling cost) is gained from recycling value of the vanadium electrolyte, which is considered to be 100% re-usable. Vanadium value at end-of-life is assumed to be the same as at beginning of life.
Total retirement costs	$/MW (Gross)	(2,138,000)	(3,359,000)	

6.5 Alternative chemistries

6.5.1 Overview

Many alternative chemistries exist in the battery energy storage system ecosystem, some of which are variations on common chemistries (such as variations on lithium-ion chemistry), and some of which involve entirely alternate reactions and compounds, such as high temperature sodium sulphur batteries or the emerging area of sodium-ion BESS products.

These are discussed at a high level below, noting that they are at a lower level of technology readiness and product maturity than the other technologies presented above, and therefore do not have ‘off-the-shelf’ benchmark characteristics.

6.5.2 Sodium ion

Sodium-ion batteries are an emerging alternative to lithium-ion technology, using sodium instead of lithium as the charge carrier. Sodium is far more abundant and widely available than lithium, making it an attractive option for reducing dependence on geographically concentrated lithium supply chains. The basic electrochemical principles of sodium-ion and lithium-ion batteries are similar, but difference in underlying chemical characteristics pose unique challenges in terms of energy density and cycle life. Early iterations of sodium-ion batteries struggled with these limitations, but recent advances in materials have significantly improved performance.

Recent trends show rapid acceleration in the commercialization of sodium-ion batteries, particularly in China, with them now being deployed in low-range EVs and stationary energy storage systems. In 2023/24, the first sodium-ion battery vehicles entered production, and large-scale manufacturing facilities began to emerge. Researchers are also exploring hybrid sodium–lithium battery systems to combine the strengths of both chemistries.

Compared to standard lithium-ion batteries, sodium-ion batteries currently offer lower energy density, meaning they’re less suited for high-performance EVs but more viable for stationary grid storage or low-cost applications. However, they have potential advantages in terms of safety, cost, thermal stability, and performance in cold climates. Additionally, sodium-ion cells are free from cobalt and nickel, reducing environmental and ethical concerns. While lithium-ion will remain dominant in the near term, sodium-ion is rapidly gaining traction as a cost-effective and scalable complement, especially in regions or sectors where raw material costs and supply chain resilience are top priorities.

6.5.3 Sodium sulphur

Sodium-sulphur (NaS) batteries are high temperature energy storage systems that use liquid sodium as the anode and liquid sulphur as the cathode. They typically operate at high temperatures (around 300-350 °C) to keep the sodium and sulphur in molten/liquid or reactive states and often use solid electrolytes or other high-temperature compatible separators to allow ion transport but block unwanted cross-contamination. Because of the high operating temperatures, there are engineering challenges around managing thermal insulation, maintaining operating temperature, sealing, and preventing degradation or hazards from reactive materials. NaS batteries are primarily used or considered for stationary, grid-scale energy storage rather than transportation applications due to their high temperature requirement and safety constraints.

When compared to a Lithium-ion alternative, NaS batteries claim to offer the following characteristics:

– Attractive degradation profile, retaining >80% energy storage capacity over a 20-year (or 7,300 cycle) life (in comparison to ~70% for a Li-ion comparator)
– Use of globally abundant materials, reducing reliance on rare metals and potentially increased prospects for re-use and recycling
– Increased resilience against microcycling (as life is related to equivalent cycles)
– Lower RTE than for equivalent Li-ion system, with NaS providing RTE in the order of 70-75% in comparison to 80-85% for Li-ion
– Energy density that is competitive with earlier generations of Li-ion batteries, especially if configured in a double-stacked arrangement (subject to O&M and HSE considerations)

6.5.4 Iron flow batteries

Iron flow batteries operate by circulating liquid electrolytes containing iron ions through electrochemical cells, where energy is stored and released via reversible redox reactions. Unlike lithium-ion systems, which store energy in solid electrodes, iron flow batteries decouple energy and power: energy capacity depends on the size of electrolyte tanks, while power depends on the cell stack. It is noted that iron flow batteries represent a hybrid flow battery technology, where the inherent functionality of the storage chemistry (i.e. material deposition) imposes a functional limit on the decoupling of energy and power. Current implementations offered in the market (such as

ESS's Energy Warehouse[331]) provide storage depth in the order of 10 hours, though changes to form factor could offer greater depth based on the same underlying technology.

Notwithstanding, this design enables flexible scaling for long-duration storage, making flow batteries particularly suitable for grid applications and renewable integration. Their aqueous electrolytes are non-flammable, enhancing safety, and iron's abundance and low cost make the technology economically attractive compared to vanadium-based systems.

Claimed advantages of iron flow batteries include:

– Use of abundant materials rather than rare and heavy metals such as lithium
– High cycle life, claiming >20,000 cycles[332] and 25 year design life with minimal degradation
– Significantly lower electrolyte cost than VRFB

Disadvantages of iron flow batteries include:

– Low round trip efficiency in comparison to lithium-ion alternatives, with iron flow batteries claiming up to 70% round trip efficiency, compared to Li-ion in the order of 85%,
– Low energy density,
– Limited track record at scale,
– Challenges associated with hybrid flow battery chemistry, such as managing side reactions (including production of hydrogen off-gas), electrolyte health management, and the inability to completely decouple energy and power components.

Overall, iron flow batteries present a promising opportunity, but face a number of challenges to compete directly with alternatives, especially as current mature technologies such as Li-ion begin to encroach on the 8+ hour storage duration territory that flow batteries are currently targeting.

6.5.5 Iron air energy storage

Iron-air energy storage technology operates on the principle of reversible rusting. During discharge, the battery absorbs oxygen from the air, converting iron into iron hydroxide (rust), while releasing electrons to produce electricity. Charging reverses this process, restoring iron and releasing oxygen. This mechanism enables the storage of energy for extended periods, making it particularly suitable for applications requiring long-duration storage, such as balancing intermittent renewable energy sources like solar and wind.

A prominent technology provider driving development of iron-air batteries is Form Energy, who claim to be developing grid-scale iron-air batteries capable of storing energy for up to 100 hours at a cost significantly lower than traditional lithium-ion batteries[333]. These advancements are driven by the need for cost-effective and sustainable energy storage solutions to support the integration of renewable energy into the grid.

While the technology is still at an early stage of maturity, the claimed advantages over alternatives such as Li-ion or flow batteries are:

– Capable of cost-effective storage up to 100 hours of depth, providing intra-day storage potential and complementing intermittent renewable energy (wind and solar) as well as short-term storage such as Li-ion,
– Improved energy density over other long duration alternatives such as flow batteries, with Form Energy claiming energy density of greater than 3 MW/acre[334] (GHD notes that the depth of storage is not defined for this claimed figure).
– Use of abundant material (iron) in the fundamental chemistry of the technology, avoiding the need for rare metals such as lithium,
– Improved safety over lithium-ion, with no heavy metals requirement and no thermal runaway risk,
– Claimed low cost given the use of low cost abundant materials.

[331] **Energy Warehouse® | ESS, Inc.**
[332] **2024-05-ESS-EnergyWarehouse-datasheet-rev9.pdf**
[333] **Battery Technology | Form Energy**
[334] **Battery Technology | Form Energy**

Disadvantages include:

- Low round trip efficiency (in the order of 50-60%[335])
- Slower charge and discharge rates, making them unsuitable to applications like EVs, emergency backup, or grid stability support,
- Limited cycle life in current technology iterations, meaning that long-term utility deployments (i.e. 20+ years in line with other offerings) is currently challenged,
- Limited maturity.

Overall, iron-air energy storage present an interesting prospect for very deep stationary energy storage using cheap and abundant materials, which may serve to fill a current market gap for cost-effective multi-day energy storage (outside of pumped hydro). Ongoing product development and improvements in cycle life and overall product maturity will be needed before this technology can be implemented at scale.

[335] **Iron-air battery - Fraunhofer UMSICHT**

7. Compressed air storage systems (CAES)

7.1.1 Overview

Compressed air energy storage (CAES) technology is an available alternative to pumped hydro and batteries, as a means to provide long duration energy storage and support high penetration of variable renewable energy. Due to its use of a synchronous generator, CAES can provide inertia and grid stability services.

As explained further below, the economics of CAES systems is driven by geological suitability, the pre-existence of any suitable storage structures, and proximity to grid nodes where storage is required.

Global Market Insights (GMI) lists the CAES global market as USD 1.6 billion in 2024 and is expected to witness a compound annual growth rate of 7.6% between 2025 and 2034[336]. GMI suggests that ~56% of projects will be for off-grid power storage and generation, presumably linked to green power purchase agreements for intermittent renewable power or else privately owned (off-grid) renewable generation. GHD notes that this prediction is slightly at odds with other generally prevailing comments that CAES has the most to offer when grid connected.

Some references also promote CAES as a black start producer, however in this role, its low-capacity factor per unit CAPEX as well as issues around its long-term loss of thermal energy makes it hard to see merit compared with other black options.

This section outlines the typical options, recent trends, technical parameters and cost parameters for CAES technology. The information listed within the respective tables has been used to populate the AEMO GenCost 2025 Excel spreadsheet in Appendix A.

7.1.2 Typical options

Figure 7-1 provides a brief overview of the principle of operation of CAES systems. In essence, charging the system involves conversion of electrical energy (often renewable) into compressed air energy. During discharge, the compressed air delivers energy to a turbine/expander, which generates electricity. Stored energy in compressed gases depends on the storage pressure and storage volume. Advanced forms of CAES use largely constant pressure/variable volume storage, which has a number of advantages as described below.

[336] Compressed Air Energy Storage (CAES) Market Size - By Technology, By Application, Analysis, Share, Growth Forecast, 2025 – 2034

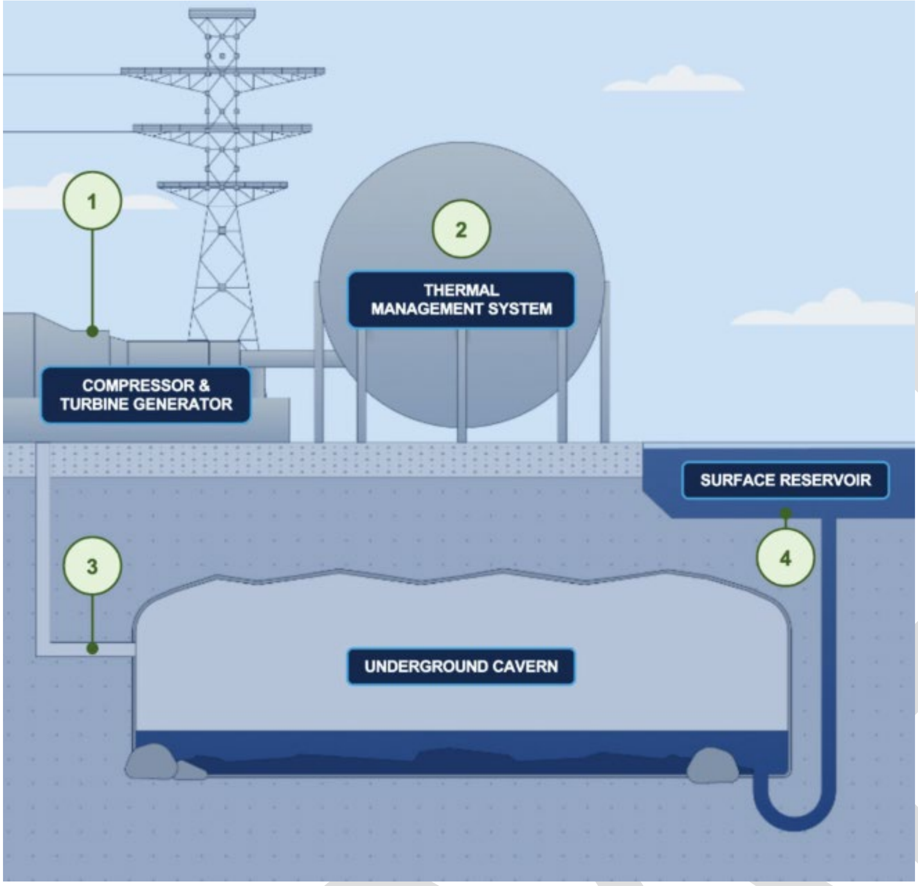


Figure 7-1 The Hydrostor Charging Process[337]

During the energy conversions and depending on the level of sophistication of the system, 20 to 40% of the energy supplied to the system is lost and not available when the system discharges energy, thus affecting round trip efficiency. The actual efficiency depends on the degree of "advanced" sophistication of the system and its duty cycle. The advanced features which give rise to the designation A-CAES chiefly comprise:

– Water compensation to achieve near-constant pressure operation, and
– Saving and using the heat of air compression.

Earlier CAES plants often did not recover heat energy generated during the compression process, and as far as GHD is aware, did not use water compensation.

Water compensation comprises a water column and a surface water reservoir which is used to maintain constant stored air pressure. This allows higher energy storage density and more efficient operation of turbines and compressors and avoids the need to pursue very high pressures which can damage some storage geological structures (typically all types, except for salt caverns). Water compensation should be considered to be a default requirement for serious consideration of future CAES projects.

The other primary feature of advanced systems is that they store the heat of compressing the air and recover this heat during the subsequent discharging of the storage system. Apart from the efficiency advantages, some level of heating can be required to prevent ice, hydrate and embrittlement hazards in the air turbine system. If the CAES system does not feature this heat recovery, then it may be necessary to heat the air upstream of the turbine using natural gas, which obviously degrades the economic and greenhouse credentials of the project. Such systems without heat re-use are known as Diabatic-CAES (D- CAES) systems. Storage of the heat of compression can be achieved using a number of storage media. A leading technology provider, Hydrostor, uses superheated water at up to 200°C.

GHD's understanding is that the duty cycle of the storage then becomes important to its round-trip efficiency. Cooled air stored in a properly sealed reservoir may approach adiabatic conditions where no pressure and

[337] Diagram from Silver City Energy Storage Website

minimal heat is lost to the geological environment. Thus, the stored energy can be maintained equally well for long or short periods. However, the heat stored in the superheated water (or other media) is contained only by the thermal insulation of its storage container, and slowly dissipates, driven by the large temperature differential. Daily and short-term duty cycles perform best because there is little time for the heat to escape before the system is discharged. Conversely, duty cycles based on long-term stand-by storage, will not return the same proportion of energy and may be less economic than say a gas turbine peaking station with a large, stored volume of fuel gas.

The other major parameter for classification of CAES systems is the type of storage container used for the compressed air. Storage is fundamentally classified into above-ground, using constructed pressure vessels of steel or potentially composite construction, or below ground. Below ground "caverns" are further classified into naturally occurring or solution-mined salt caverns, purpose-excavated hard rock caverns and disused infrastructure such as old mine sites.

7.1.3 Recent trends

GHD determined that it could add the best value to the understanding of CAES costs in 2025 by reviewing the 2024 report[338] and then reviewing the status of projects under development which have reached construction or advanced development status, to explore whether emerging real cost data validates the previous estimates.

Actual cost data is limited and cost estimates for projects under development are often more speculative than firm.

GHD reviewed the 2024 dataset and report, which considered two projects, a 200MW x 24 hr cavern project and 50MW x 12 hr vessel project.

The following cost metrics were extracted from the 2024 report.

Table 7.1 Calculated cost metrics from 2024 report[339]

Cost (A$)	200MW x 24 hr cavern	50MW x 12 hr vessel
Cost per MW	AU$7.59 M	AU$11.1 M
Cost per MWh	AU$0.32 M	AU$0.92 M

The 2024 estimate uses a ratio of total installation cost to equipment cost of ~1.42. In most of GHD's estimates for similar infrastructure, this is usually in the range of 2-3.

Recent developments with commercial scale planned and operating CAES projects are described below.

Silver City 200MW x 8hr = 1,600 MWh

Canadian company, Hydrostor, has secured NSW government approval to build a 200MW/1.6GWh A-CAES facility near Broken Hill. The project describes a capital cost of AU$652 million, however an Australian Financial Review Report (2 September 2024) cites a cost range of AU$0.6-1B. Using the company-cited figure, the cost metrics are:

– AU$3.26 million per MW
– AU$0.41 million per MWh

Silver City's/Hydrostor's intention is to excavate a purpose-built hard rock cavern which is indicated by a stakeholder presentation to have a storage depth of approximately 500m and a volume of nominally 275,000 cubic metres.

Yengchu-1 300MW x 5 hrs = 1,500 MWh

Yingcheng Hubei (Nengchu-1) is a major Chinese A-CAES project brought online to the grid in January 2025, with media citing a cost of US$270M. The resulting cost metrics are:

– AU$1.36 million per MW[340]

[338] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)
[339] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)
[340] Exchange rate of AUD 1 = USD 0.66 has been used

– AU$0.27 million per MWh[340]

ZCGN 300 MW x 6hrs = 1,800 MWh

This is a second major Chinese project which connected to the grid in April 2024 and is the largest in the world. It is also claiming to be the most efficient with round-trip efficiency of 72.1%. The project also uses salt cavern storage (1,000m deep). Reported capital cost was US$207.8 million. The resulting cost metrics are:

– AU$1.05 million per MW[340]
– AU$0.17 million per MWh[340]

Willow Rock 500MW x 8 hours = 4,000 MWh

Hydrostor have another A-CAES project under development at the Willow Rock Storage Centre in Kern County, California, situated on a 60-acre site with interconnection to the SCE Whirlwind Substation. The first offtake agreement was signed in early 2023 and the project filed an SAFC application in March 2024. Media release states that momentum is building for the project, however there is also reference to the project potentially being relocated to a site with better geology. Hydrostor acknowledges that the planned operational date is sliding from the planned 2028 date and has suggested 2030.

The project does not exploit any kind of pre-existing geological storage structure but excavates a structure within suitable hardrock. Media reports describe the storage structure as having a depth of approximately 600m and dimensions of approximately 0.5-hectare area x 90m height.

The project budget is US$1.76 billion. Notwithstanding the large capacity of the project, it is apparent that considerable costs arise from the need to excavate the storage caverns. The resulting cost metrics are:

– AU$5.3 million per MW[340]
– AU$0.67 million per MWh[340]

Augwind Air Battery- Germany

Augwind have a project under development, although the scale is listed as 3-8GWh and the cost is a wide range of €7-15 million. A 250kW pilot-scale project preceded it. Cost estimates are not sufficiently resolved to be usable.

Corre Energy- Netherlands

Corre Energy is developing several major A-CAES and hybrid hydrogen storage projects across Europe, led by a 320MW x 84 hour (27GWh) project called ZW1 in Zuidwending, Groningen, The Netherlands. The project proposes to use salt cavern storage. It is at an early stage, and no capital cost projections could be found.

Energy Dome

Energy Dome does not use Adiabatic Compressed Air Energy Storage but rather proposes long-duration energy storage with a CO_2-based thermo-mechanical system. The technology is similar to A-CAES but is not suitable for cost referencing.

Older Projects

There are few other analogues for actually operating CAES projects. The 290MW / 580MWh Huntorf project in Germany was built in 1978. The McIntosh Alabama plant was built in 1991 and has a rating of 110MW. Both projects use salt cavern storage. For Huntorf, the estimated construction cost was US$90M. If currency-converted and indexed for inflation over the admittedly long intervening years, the resulting metric would be approximately A$1.5M/MW[340], which is comparable to the Nengchu metric.

Both Huntorf and McIntosh use the older D-CAES technology. The absence of heat storage and pressure balancing, as well as the time period since their construction makes these unsuitable for use as cost reference points.

Demonstration and Smaller Scale Projects

An Australian A-CAES project of 5MW/10MWh was proposed for Angas Strathalbyn in South Australia (Green Y project) at a disused zinc mine, however the project was discontinued in 2021. GHD is not aware of other active Australian pilot projects.

As mentioned above, Hydrostor have operated demonstration scale projects in Canada (1.75MW/7MWh). It is not recommended to extrapolate from the costs of such projects, due to differences in scale.

At the smaller end of the capacity range, Cheesecake Energy and Sherwood Power (UK based) are promoting small scale CAES which could align with the 2024 cost estimates for modular, surface-mounted storage vessels at a future stage. The companies are still prototyping equipment and cost data is unavailable / insufficient at this stage.

7.1.3.1 Summary of changes

Compared to the 2024 report, the capacity (duration) of cavern storage has been reduced in line with available examples (200MW x 24hr used in 2024, compared to 200MW x 8hr used in 2025). The capacity of the vessel system has remained the same (50MW x 12hr).

Installation cost for the vessel storage case has been increased to reflect a refined ratio vs equipment costs.

O&M costs are approximately half of those reported in 2024 on a per unit basis. GHD's costs have been largely sourced from reference projects and publicly available O&M cost data.

7.1.4 Selected hypothetical project

CAES is one of the newest energy technologies, and reference or analogue projects to provide reliable reference cost data are rare. The technology is well short of demonstrating progress down the cost improvement curve. Not enough data exists to provide comment on the future economies of scale that may be available.

A key point is that project cost varies widely depending on the type of storage technology. GHD's view is that this variation will be more significant than regional construction cost rate differences (even between extremes such as China and Australia) and will also eclipse the effect of time-based inflation up to a period of even one decade. The storage technologies are listed below in order of increasing cost, based on information available.

Table 7.2 Cost ranking of CAES projects

Ranking of cost (low to high)	Storage Technology	Comment
1. Lowest cost	Salt caverns	Naturally well-sealed with low geological risk, shapable and proven from natural gas and (limited) hydrogen storage projects. However, their location rarely coincides with optimal electricity grid storage nodes.
2.	Porous rock formations	Very large storage volumes are available, however sealing cost and geological risk are more significant.
3.	Disused mines or caverns	The pre-existence of the structure can dramatically reduce cost, although cost risk is high due to uncertainty in scoping sealing operations and some geological risk. It is very unlikely that structure will coincide with a grid location requiring energy storage.
4.	Manufactured hard rock caverns	Complete excavation of the structure adds significantly to cost, although the ability to locate the project based on optimal grid storage nodes is greatly improved. (Department of Energy data has suggested that 80% of onshore geology in the US is suitable.)
5. Highest cost	Surface Vessels	The compressed air is stored in manufactured pressure vessels, located above-ground. Cost is predictably much greater, although geological risk is absent and cost certainty is higher. Land requirements can be more extensive. The technology can be located to suit optimal electricity grid locations. Costs tend to limit project size.

Some evidence to support the over-riding importance of storage technology in the estimation of costs can be seen in the following comparison of commercial scale CAES projects, based on their reported development status in 2024-25. These projects span the range of geological storage technologies.

Table 7.3 Power and storage costs for commercial scale CAES projects

Project	Project Status	Storage technology	Power Cost (AU$M/MW)[341]	Storage Cost (AU$M/MWh)[341]
ZCGN China Commissioned 2024 300MW x 6 hrs	Operational	Salt cavern	1.05	0.17
Nengchu-1 China Commissioned Jan 25 300MW x 5 hrs	Operational	Disused (salt) mine	1.36	0.27
Hydrostor Silver City Australia In development 200MW x 8 hrs	Development	Greenfield hard rock	3.26	0.41
Hydrostor Willow Rock USA In development 500MW x 8 hrs	Development	Greenfield hard rock	5.3	0.67
2024 Hypothetical Australian Project 200MW x 24hr	N/A	Cavern type unknown	7.59	0.32
2024 Hypothetical Australian Project 50 X 12 hr	N/A	Above ground vessels	11.1	0.92

The Chinese projects' reported cost metrics are the lowest and show the benefits of having access to salt caverns or existing geological structures with good inherent sealing. It's relevance to Australia is limited greatly by the general lack of suitable salt cavern locations in Australia. GHD is unaware of any suitable caverns with usable storage volume, although Geoscience Australia has identified the Canning Basin (WA), Adavale Basin (Qld) and Polda Basin (SA) as salt deposits where solution mining technology could possibly be used to create gas storage caverns. Chinese construction costs are also at the opposite end of the spectrum to Australia.

It is noted that the Silver City and Willow Rock projects both use greenfield cavern storage, both have site location cost factors that are similar, and are at similar development stages. However, they show a disparity in cost metrics, with the US project being more expensive despite potential economies of scale arising from its capacity being 2.5 times larger.

For the 2024 costs, it is unclear whether these assumed greenfield cavern construction or if some level of credit may have been taken for re-using an existing underground structure. As mentioned above, there is also some uncertainty about the construction/installation cost of the purchased equipment.

In terms of a cost analogue that could be suitable for use on multiple future Australian projects, with locations fixed by the need for storage or grid stabilisation, the US-based Willow Rock project is considered by GHD at this time to be the best cost analogue. Its cost metrics are AU$5.3M/MW and AU$0.67M/MWh.

This forms the basis of the hypothetical project for this Report, however the capacity has been reduced from the scale of the US Willow Rock project to 200MW (from 500MW), which is a more representative size for the Australian electricity grid. The storage duration of 8 hours from the US project is considered to be realistic for the Australian setting. The 24 hour storage concept in the 2024 report is a very long storage duration compared to any other storage technology.

The 2024-proposed 50MW x 12 hour project has also been presented below, although its installation cost multiplier has been increased, resulting in higher predicted costs in this Report. The larger project could readily play a role in NEM energy storage, whilst the smaller project seems more appropriate as a behind-the-meter project based on a rationale of back-up storage for industries where there may be high costs if mains power to their processes are interrupted.

[341] Exchange rate of AUD 1 = USD 0.66 has been used

Table 7.4 Configuration and performance – Compressed air storage system

Item	Unit	50MW x 12 hours storage	200MW x 8 hours storage	Comment
Configuration				
Technology		A-CAES (with vessel storage)	A-CAES (with cavern storage)	
Performance				
Power capacity (Gross)	MW	50	200	
Energy capacity	MWh	600	1,600	
Auxiliary power consumption (operating)	kW	Negligible	Negligible	
Auxiliary power consumption (standby)	kW	Negligible	Negligible	
Power capacity (Net)	MW	50	200	
Seasonal rating – Summer (Net)	MW	50	200	
Seasonal rating – not summer (Net)	MW	50	200	
Cavern/vessel air pressure	bar	70	70-100	Vessel pressure based on cost-effective vessel designs- higher pressures are possible.
Cavern/vessel air volume	m^3	TBA	275,000	Based on Silver City storage volume. Vessel volume cannot be scaled from caverns, as it is isochoric storage and the cavern is isobaric. Design work required.
Surface reservoir volume	m^3	N/A	Approx equal to air volume.	Assumes that vessel storage is isochoric with no water compensation.
Thermal storage medium / temperature / pressure	Fluid / °C / barg	Various medium options, but if water, would be superheated / 200-210°C / 16-20barg	Superheated water / 200-210°C / 16-20 barg (estimated)	
Annual performance				
Average planned maintenance	Days / year	3	3	
Equivalent forced outage rate	%	2	2	
Annual number of full cycles		0-350, noting that the number of cycles and depth of 'discharge' may be constrained depending on fatigue impact on vessels, to preserve vessel life	0-350	Cavern project would typically be operated for max cycles. Max is based on ~24hr charge /discharge period.
Annual degradation over design life	%	Negligible	Negligible	

Table 7.5 Technical parameters and project timeline – Compressed air storage system

Item	Unit	50MW x 12 hours storage	200 MW x 8 hours storage	Comment
Technical parameters				
Technology		A-CAES (with vessel storage)	A-CAES (with cavern storage)	
Ramp up rate	% / min	25	25	
Ramp down rate	% / min	25	25	
Round trip efficiency (Beginning of life)	%	55-65	60-70	Reduced efficiency for vessel project accounts for variable pressure turbine operation. Note that the benchmark efficiency for a China operating project is 72%.
Response time (time from signal to full charge and time from signal to initial discharge)	Min	5	5	1 minute to start. 4 minutes to ramp
Synchronous condenser mode (Auxiliary power requirement)	%	0.5-2% of rating	0.5-2% of rating	
Allowable maximum state of charge	%	100	100	
Allowable minimum state of charge	%	Typically 30% (expressed as % of max storage pressure) if a long operating life and significant number of annual cycles are required.	0 for A-CAES systems.	May be limited to a minimum greater than 0 for non-water compensated CAES caverns (due to geo-mechanical properties) and for vessels (due to steel fatigue issues).
Project timeline				
Time for development	Years	2 (Australia)	2-5 (Australia)	2-4 years for on-line China projects
First year assumed commercially viable of construction	Year	2025	2025	
EPC programme	Years	2	3	
– Total lead time	Years	1.5-2	1.5-2	For rotating equipment
– Construction time	Weeks	80-100	100-150	Underground project duration set by excavation time
Economic life (Design life)	Years	30	30	Standard for rotating plant
Technical life (Operational life)	Years	30-50	30-50	Standard for rotating plant

7.1.5 Development cost estimates

The following table provides CAPEX cost estimates for the defined CAES projects.

Table 7.6 Development cost estimates – Compressed air storage system

Item	Unit	50MW x 12 hours storage (vessel)	200MW x 8 hours storage (cavern)	Comment
CAPEX – EPC cost				
Relative cost – Power basis	$/kW (Net)	41,480	5,300	Cavern cost is based on Willow Rock US-based project (refer Table 7.3). This is assumed to be an all-inclusive cost. Due to the lack of vessel-based reference projects, vessel costs from 2024 have been reinstated and increased to account for a larger installation cost factor. This does not include land and development costs.
Relative cost – Energy basis	$/kWh	3,457	670	-
Total EPC cost	$	2,037,000,000	1,055,000,000	-
– Equipment cost	$	1,037,000,000	260,000,000	-
– Installation cost	$	1,000,000,000	795,000,000	Assumes a 2.0 installation multiplier for the vessel project. Assumes that cavern construction is the dominant component of cavern EPC cost.
Cost of land and development	$	37,000,000	10,000,000	
Total Cost	**$**	**2,074,000,000**	**1,065,000,000**	Based on relative storage cost

7.1.6 O&M cost estimates

The following table provides fixed, variable and total annual O&M cost estimates for the defined CAES projects.

Table 7.7 O&M cost estimates – Compressed air storage system

Item	Unit	50MW x 12 hours storage (vessel)	200MW x 8 hours storage (cavern)	Comment
Fixed O&M cost	$ / MW / year (Net)	16,000	14,400	Reference cost in public domain, assumed to apply to vessel storage, scaled for currency and inflation[342]. Cavern assumed 10% less due to reduced need for vessel maintenance.
Variable O&M cost	$ / MWh (Net)	2.78	2.5	Reference cost in public domain, assumed to apply to the vessel case, scaled for currency and inflation[343]. Cavern assumed to be 10% less due to the lack of fatigue impact potentially present with vessels.
Total annual O&M cost	$M	1.4	4.3	Assuming full nameplate capacity charged and discharged on each operational day.

[342] **How do maintenance costs for CAES and PHS systems compare | NenPower**
[343] **How do maintenance costs for CAES and PHS systems compare | NenPower**

7.1.7 Retirement cost estimates

Table 7.8 Retirement cost estimates – Compressed air storage system

Item	Unit	50MW x 12 hours storage	200MW x 8 hours storage	Comment
Decommissioning, demolition & rehabilitation costs	$/MW (Net)	98,000	98,000	Scaled off equivalent cost for steam power block / HV infrastructure
Disposal costs	$/MW (Net)	154,000	20,000	Higher cost for 50MW case due removal and disposal of above ground storage
Recycling costs	$/MW (Net)	(119,000)	(27,000)	Higher net revenue for 50MW case due recycling value of steel for above ground storage
Total retirement costs	$/MW (Net)	133,000	91,000	

8. Location factors

8.1 General (Non PHES) location factors

The AEMO Draft 2025 IASR Stage 1 notes that costs for various technologies are based on the assumption that projects (except offshore wind projects) are located in metropolitan areas. For projects that are not located in the metropolitan areas, a location cost factor needs to be applied. In this case the locational cost factors are relative to cost of construction in Melbourne which has a factor of 1.0. The intention of this is to provide an indication of the variation in project cost between metropolitan and regional areas.

The locational cost factors consider:

– Equipment costs
– Installation costs
– Fuel connection costs – if applicable
– Cost of land and development

The incremental cost of developing and executing a major project in a given location is nominally based on factors such as:

– Transportation costs associated with distance from a major port
– Labour rates and labour availability in remote locations
– Increased cost of working in remote location due to lack of amenities and industry

These are costs common to all major projects, although some components may vary depending on the technology. Two previous studies prepared for AEMO have been referenced in developing these factors. The two referenced studies are:

– Aurecon (2024) Energy Technology Cost and Parameters Review - Revision 3[344]
– GHD (2018) AEMO Cost and Technical Parameter Review – Revision 3[345]

The Aurecon Report referenced cost factors for the various potential renewable energy zones, while the GHD study was based on nominal regions before the NEM sub-regions were developed. Hence, some degree of interpretation is required to compare the two studies.

8.1.1 Equipment cost factors

Equipment cost factors for the regions reflect an incremental transport/shipping cost relative to delivery to a plant located near a major port.

The GHD 2018[346] approach was that all major port locations were assigned an equipment cost factor of 1.00. Regions further from a major port receive a factor ranging from 1.05 to 1.10 based on distance from the port, reflecting the scale of additional transportation required (i.e. level of remoteness). The 2024 report[347] adopted factors varying between 1.01 and 1.15, depending upon the distance from both capital cities and ports. It is unclear how the two equipment cost factors were applied in 2024. The differences between the adopted factors in these two approaches is generally small. The exception is Queensland, where the 2024 assumption that equipment factors should be based on distance from Brisbane resulted in very high factors for northern Queensland, whereas utilising ports[348] at major cities further north should result in lower factors. Hence, the GHD 2018[349] factors were considered more appropriate and adopted for this current study.

For most energy projects, the major equipment has a high manufacture and shipping cost prior to reaching Australia. Hence, the additional equipment cost of transport to more remote sites may not be as large a

[344] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)
[345] GHD 2018 AEMO Costs and technical parameter review
[346] GHD 2018 AEMO Costs and technical parameter review
[347] Aurecon (2024) 2024 Energy Technology Cost and Technical Parameter Review (Revision 3)
[348] Port fees have not been considered however it is assumed that port fees will be insignificant relative to transport costs.
[349] GHD 2018 AEMO Costs and technical parameter review

differentiator as the installation cost and equipment factors were assumed to only vary from 1.0 to 1.1. Equipment cost factors have been defined based on distance from major city / port using the maps attached as Appendix B (from GHD 2018[350]) as follows:

Table 8.1 Equipment cost factors

Distance from major city / port	Low	Medium	High
Factor	1.0	1.05	1.1

8.1.2 Installation cost factors

Installation cost factors include material, labour, mobilisation and demobilisation of resources from metropolitan areas. Both previous studies developed these using a blend of labour and bulk material rates using previous issues of the cost estimating reference *Rawlinsons Australian Construction Handbook*.

Adopting a similar approach, Rawlinsons 2025[351] was used for the current study. The guide is intended for commercial building construction and does not have specific rates for heavy civil construction. Also, Tier 1 contractors typically engaged for large project delivery will usually have more even cost distribution across Australia than may be suggested by Rawlinsons. However, it is the most suitable reference for general construction in Australia.

Rawlinsons[352] provides unit rates for building construction activities within each capital city, which allows a relative factor to be developed between these locations. A factor for the capital cities was derived from the published unit rates considering a blend of 15% earthworks, 5% foundation works, 20% reinforced concrete, 20% overall building index and 50% labour rates (electrical trades and general labour). The capital city based installation factors are shown in Table 8.2.

Table 8.2 Capital city based installation cost factors for NEM

City	Factor relative to Melbourne
Melbourne	1.00
Adelaide	0.95
Brisbane	0.98
Sydney	1.06
Hobart	0.94 (based on building price index only – no data for other factors in Rawlinsons)

The capital city factor was then extended to regional locations using state-based cost factor maps provided in Rawlinsons[353] to apply additional cost increases due to remoteness relative to the capital city. This increases the cost factor and results in the installation cost factors in Table 8.3.

8.1.3 Fuel connection costs

Fuel costs considered for some generation types in the NEM may include fuel used to be converted from chemical form to electric energy form which may have a significant cost. For most renewable technologies fuel connection costs have been assumed to be zero.

8.1.4 Cost of land and development

The cost of land and development is considered to be a collation of an allowance to procure or lease land, and environmental offset costs. These costs are heavily dependent on a number of factors that do not necessarily align with geographical variance. For example, while land cost might typically reduce as the project location becomes more remote, the costs associated with land development, access, and community engagement may

[350] GHD 2018 AEMO Costs and technical parameter review
[351] Rawlinsons 2025 Rawlinsons Australian Construction Handbook
[352] Rawlinsons 2025 Rawlinsons Australian Construction Handbook
[353] Rawlinsons 2025 Rawlinsons Australian Construction Handbook

increase. Additionally, the land may be high value grazing or farming land which would counteract the remoteness factor.

GHD[354] estimated property costs and environmental offset costs for NEM transmission cost estimates. The same methodology has been adopted in this current study to estimate the cost of land and development.

Owners' costs including financing, and site development costs (access roads, site establishment, camps etc.) may also be considered a cost of development. These are not site specific at a NEM sub-region scale and will not have an impact on locational cost factors. Hence these are not included.

Property costs

GHD used Australian Bureau of Agricultural and Resource Economics and Sciences[355],[356](ABARES) as an independent and reliable source for land prices, to collect the most recent farmland pricing data, for all subregions within the NEM. The average of all the subregions farmland pricing data, in $\$/m^2$ was then used to derive the Property Costs component.

Environmental offset costs

Estimating biodiversity offsets at early project stages is highly uncertain, in the absence of detailed vegetation and threatened species surveys, which are essential for precise calculations. Obtaining published vegetation class mapping for the entire NEM to provide some differentiation between particular sites is beyond the scope of this study. However, as these costs can be significant and do vary by state there is some value in including a baseline estimate of state based costs considering the size of different schemes.

To calculate Environmental offset costs, GHD reviewed several biodiversity offset estimation methods, available to each state based on their respective jurisdictional environmental regulations, and also the federal government methodology. Only NSW has a federally approved methodology to estimate biodiversity offset costs. Applying a different methodology to NSW may skew the results, and hence only the federal method was adopted for all NEM sub-regions. The formula used for deriving the federal biodiversity offset rate is as follows:

Federal biodiversity offset rate ($\$/m^2$) *= Impact area* ($m^2$) *× Impact area multiplier × Land price* ($\$/m^2$)

Where:

– Impact area is the total land size effected by constructing the infrastructure
– Impact area multiplier is used to increase the biodiversity cost of impacted area. GHD has assumed the average impact area multiplier of 10 to be representative of majority of projects that have required biodiversity offset costs.
– Land price sourced from ABARES described above

Cost of Land and Development

The property costs and environmental offset costs for each location are summed, and a cost factor determined by dividing the location cost by the overall average cost. While the cost factors near Sydney and Melbourne appear low, reflecting that the ABARES database for broadacre farming land sales is not relevant for metropolitan areas, Projects in these areas would only be possible on available land such as repurposed mine voids rather than purchasing land zoned for another purpose.

As noted in the preceding text, there is significant uncertainty in these cost factor estimates, and they should be used with caution.

8.1.5 Operation and maintenance costs

O&M costs will typically include some equipment and materials and a high labour component, as is largely reflected by the Installation cost factor. It would be rare that very large equipment loads would be required and

[354] GHD 2025 ISP Transmission Cost Database Tool: 2025 Update
[355] Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES) Farmland Price Indicator **ABARES Farmland Price Indicator - DAFF**
[356] Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES) Region Map **https://www.agriculture.gov.au/sites/default/files/images/aus-broadacre-zones-regions.jpg**

hence the equipment cost factor has lower influence on O&M costs. Where used in this Report, the O&M cost factor has been taken as the same as the Installation cost factor.

8.1.6 Estimate of location factors in the NEM region

The locational cost factors developed in the preceding sections are summarised in Table 8.3. Where used in this Report, locational cost factors can be multiplied by the estimated installation, equipment, land and development costs for each technology.

Table 8.3 Summary of locational cost factors by NEM sub-region

State	REZ Code	Region	Site/City	Equipment cost factor	Land and development cost factor	Installation cost factor / O&M factor
Qld	Q1	Far North Qld	Cooktown	1.00	1.29	1.37
Qld			Port Douglas	1.00	1.29	1.13
Qld			Cairns	1.00	1.29	1.08
Qld			Innisfail	1.00	1.29	1.16
Qld	Q2	North Qld Clean Energy Hub	Richmond	1.05	0.29	1.37
Qld			Hughenden	1.05	0.29	1.37
Qld	Q3	Northern Qld	Ingham	1.00	1.29	1.17
Qld			Townsville	1.00	1.29	1.14
Qld	Q4	Isaac	Cardowan	1.00	0.88	1.15
Qld			Moranbah	1.00	0.88	1.19
Qld	Q5	Barcaldine	Longreach	1.10	0.06	1.32
Qld	Q6	Fitzroy	Rockhampton	1.00	0.88	1.15
Qld			Biloela	1.00	0.47	1.15
Qld			Gladstone	1.00	0.88	1.15
Qld	Q7	Wide Bay	Bundaberg	1.05	0.88	1.05
Qld			Gympie	1.00	0.88	1.05
Qld			Nambour	1.00	0.88	1.00
Qld		S.E. Coast	Maroochydore	1.00	0.88	1.00
Qld	Q8	Darling Downs	Dalby	1.05	1.05	1.04
Qld			Toowoomba	1.00	1.05	1.00
Qld			Warwick	1.00	1.05	1.04
Qld			Inglewood	1.05	1.05	1.08
Qld			Texas	1.05	1.05	1.13
Qld			Charleville	1.10	0.06	1.23
Qld			Roma	1.05	0.47	1.15
Qld	Q9	Banana	Emerald	1.05	0.47	1.23
Qld	Q10	Collinsville	Bowen	1.00	1.29	1.17
Qld			Mackay	1.00	1.29	1.15
NSW	N1	North West NSW	Moree	1.05	0.42	1.20
NSW			Narrabri	1.05	0.42	1.22
NSW			Gunnedah	1.05	0.42	1.22
NSW	N2	New England	Armidale	1.00	1.09	1.17

State	REZ Code	Region	Site/City	Equipment cost factor	Land and development cost factor	Installation cost factor / O&M factor
NSW		Northern Tablelands	Glen Innes	1.00	1.09	1.19
NSW		North West Slopes & Plains	Tamworth	1.05	0.42	1.11
NSW			Inverell	1.05	0.42	1.22
NSW	N3	Central-West Orana	Dubbo	1.05	0.85	1.14
NSW		Central West Slopes & Plains	Coonabarabran	1.05	0.85	1.25
NSW		Central Tablelands	Mudgee	1.05	0.85	1.19
NSW	N4	Broken Hill	Broken Hill	1.10	0.20	1.34
NSW	N5	South West NSW	Deniliquin	1.10	1.45	1.22
NSW			Hay	1.10	1.45	1.27
NSW	N6	Wagga Wagga	Albury	1.10	1.45	1.07
NSW			Griffith	1.05	1.45	1.14
NSW			Wagga Wagga	1.05	1.45	1.09
NSW	N7	Tumut	Perisher Valley	1.05	1.09	1.33
NSW			Cabramurra	1.05	1.09	1.27
NSW			Jindabyne	1.05	1.09	1.26
NSW			Canberra	1.05	1.09	1.08
NSW			Braidwood	1.05	1.09	1.11
NSW			Goulburn	1.00	1.09	1.14
NSW	N8	Cooma-Monaro	Eden	1.05	1.17	1.18
NSW			Bega	1.05	1.17	1.19
NSW			Bombala	1.05	1.09	1.22
NSW	N9	Hunter-Central Coast	Singleton	1.00	1.09	1.14
NSW			Newcastle	1.00	1.17	1.07
NSW	N12	Illawarra	Nowra	1.00	1.17	1.09
NSW			Bowral	1.00	1.17	1.09
NSW			Wollongong	1.00	1.17	1.07
NSW	N13	South Cobar	Cobar	1.10	0.42	1.42
Vic	V1	Ovens Murray	Corryong	1.10	1.52	1.08
Vic			Bright	1.05	1.52	1.05
Vic			Mount Buller	1.00	1.52	1.05
Vic			Omeo	1.05	1.52	1.05
Vic	V2	Murray River	Mildura	1.10	0.60	1.05
Vic			Ouyen	1.10	0.60	1.02
Vic			Kerang	1.10	0.60	1.02
Vic	V3	Western Victoria	Ballarat	1.00	1.52	1.00
Vic			Ararat	1.05	1.52	1.01

State	REZ Code	Region	Site/City	Equipment cost factor	Land and development cost factor	Installation cost factor / O&M factor
Vic			Horsham	1.10	1.06	1.01
Vic			Kaniva	1.10	1.06	1.06
Vic	V4	South West Victoria	Casterton	1.10	1.52	1.06
Vic			Portland	1.10	1.52	1.03
Vic			Hamilton	1.10	1.52	1.03
Vic			Warrnambool	1.05	1.52	1.01
Vic	V5	Gippsland	Sale	1.05	1.52	1.02
Vic			Morwell	1.00	1.52	1.00
Vic		Central North Victoria	Bendigo	1.00	1.19	1.00
Vic			Shepparton	1.05	1.19	1.01
Vic			Seymour	1.00	1.52	1.00
Tas	T1	North East Tasmania	Launceston	1.00	1.68	0.89
Tas			Scottsdale	1.00	1.68	0.99
Tas	T2	North West Tasmania	Queenstown	1.10	1.68	1.18
Tas			Smithton	1.10	1.68	1.01
Tas	T3	Central Highlands	Hobart	1.00	1.68	0.94
Tas			Derwent Valley Council	1.00	1.68	0.99
Tas			Swansea	1.05	1.68	1.08
Tas			Bothwell	1.05	1.68	1.03
SA	S1	South East SA	Murray Bridge	1.00	0.77	1.00
SA			Keith	1.05	1.49	1.09
SA			Naracoorte	1.05	1.49	1.09
SA			Mount Gambier	1.05	1.49	1.09
SA	S2	Riverland	Renmark	1.05	0.77	1.14
SA			Berri	1.00	0.77	1.09
SA	S3	Mid-North SA	Kapunda	1.00	0.77	1.00
SA			Port Pirie	1.05	0.77	1.05
SA			Adelaide	1.00	0.77	0.95
SA			Clare	1.00	0.77	1.05
SA	S4	Yorke Peninsula	Yorketown	1.00	0.77	1.09
SA			Maitland	1.00	0.77	1.09
SA			Wallaroo	1.00	0.77	1.05
SA	S5	Northern SA	Whyalla	1.05	0.21	1.09
SA			Port Augusta	1.05	0.77	1.09
SA			Leigh Creek	1.10	0.20	1.24
SA			Peterborough	1.05	0.77	1.14
SA	S6	Roxby Downs	Coober Pedy	1.10	0.20	1.33
SA			Roxby Downs	1.10	0.20	1.24
SA	S7		Cleve	1.05	0.21	1.11

State	REZ Code	Region	Site/City	Equipment cost factor	Land and development cost factor	Installation cost factor / O&M factor
SA		Eastern Eyre Peninsula	Port Lincoln	1.05	0.21	1.14
SA	S8	Western Eyre Peninsula	Ceduna	1.10	0.21	1.24
SA			Elliston	1.05	0.21	1.19

8.2 PHES location factors

PHES projects are unique large-scale infrastructure investments and the site-specific costs for construction will have a much greater influence on locational cost factors than for other energy technologies that can be constructed in more varied locations. Hence, AEMO have requested that separate location cost factors be developed for PHES. GHD[357] prepared estimates for locational cost factors for PHES in each NEM sub-region which are summarised here.

8.2.1 Topography factor

PHES projects will have varying costs for each element and overall costs will vary greatly between sites. This is due to both systemic risks and project-specific factors such as geology, topography, access constraints, water availability, transmission availability, land acquisition and biodiversity offset costs. Hence, determining a realistic locational cost factor is difficult and will not represent every individual project.

Despite that, there will likely be differences in cost for various regions in the NEM based on the topography of each region which can be explored. Reasons for these differences may include:

– The waterway length to head ratio typically reflects the civil construction cost of tunnels relative to the power capacity of the scheme – projects with lower waterway length to head ratios are generally cheaper. Similarly dam embankment costs vary with topography as some sites will be suitable for small valley dams impounding large reservoirs, while flatter sites may require a large volume of dam embankment forming a 'turkeys nest' dam all around the reservoir.

– The installed capacity for a project is a significant driver in determining the unit cost because some PHES costs are fixed while others are variable. Installed capacity is related to head and storage size. In regions where storages are relatively small and head is relatively low; costs are generally higher.

A 'Topography Cost Factor' was developed by GHD[358] that attempts to capture differences in PHES development cost for various regions in the NEM based on the topography of each region. This was estimated by dividing the estimated cost of PHES development in a subregion by the average estimated cost for the whole NEM. This enables a comparison amongst the identified schemes for each NEM sub-region as shown in Table 8.4.

The topography factors vary from 0.71 to 1.27 with an average of 1.0. A lower topography factor for a given region and storage duration suggests that the region is either more suitable for PHES development or contains a greater number of efficient and cost-effective PHES candidate sites for that duration. For example, as shown in Table 8.4, the overall topography factor for the NNSW region is generally lower than that of other regions — particularly for the 48 hour and 160-hour durations.

Conversely, Central Queensland (CQ) subregion has a low topography cost factor for 10-, 24- and 48-hour generation and high factor for 160-hour generation. This was because only two 160-hour duration projects were identified in CQ, both with an ANU[359] cost ranking of A compared with AA for the NNSW sites. The parametric cost estimates in this study also suggested higher costs for these sites relative to others. This suggests that CQ may be more appropriate for storage durations up to 48 hours and less suitable for seasonal (160 hr) storage.

[357] GHD 2025 AEMO Pumped Hydro Energy Storage Parameter Review
[358] GHD 2025 AEMO Pumped Hydro Energy Storage Parameter Review
[359] Andrew Blakers, Bin Lu and Matthew Stocks, Australian National University, (2017) 100% renewable electricity in Australia, **http://www.sciencedirect.com/science/article/pii/S0360544217309568**

Table 8.4 Topography cost factor

Location (NEM Subregion)	Generation Duration (hrs)			
	10	24	48	160
CNSW	-	0.93	0.96	0.86
NNSW	0.96	0.95	0.76	0.71
SNSW	1.12	1.02	1.25	1.02
SNW	-	-	-	-
CQ	1.03	1.04	0.81	1.27
NQ	1.07	0.92	0.85	0.84
SQ	0.86	1.06	1.10	-
CSA	-	1.07	-	-
NSA	-	1.11	1.24	
TAS	0.98	-	0.99	1.18
WNV	0.97	0.90	1.03	1.11
Average	0.98	1.02	0.99	1.02

Note: Where no data was available to develop a cost estimate in a sub-region, the average value for that generation duration was adopted to generate topography cost factors. The rationale for this was that while there were no schemes identified in the GHD 2025[360] study, there may be possible schemes in that subregion, and a cost factor is required. Typically, if a developer proposes a scheme within a region, it has likely been selected to have features that would have relatively low costs. Since there is no data, it was considered too ambitious to apply a low topographic factor, but the average was considered a reasonable assumption.

8.2.2 Weighting of cost factors for PHES

In AEMO and CSIRO's modelling, the cost to develop PHES is determined by multiplying the base cost ($/MW for the required duration) by a single locational cost factor. Hence, each of the cost factors developed in preceding sections require a weighting to determine an overall combined locational cost factor. This weighting does not apply to particular parts of a cost estimate, for example the installation cost factor is not directly applied to a portion of the base cost that represents installation related items in an estimate, instead they represent the approximate influence or weighting of the five factors to the overall cost.

PHES projects have a large component of on-site civil works including surface earthworks, tunnelling and powerhouse excavation, mass and structural concrete, and the associated site overheads for these works. A cost estimate is typically built up by multiplying the quantities of materials (concrete, tunnelling etc.) by a rate for that activity. The main influences on these factors are:

– Quantities of materials can be seen as influenced by topography – suitable topography will have shorter tunnels for example
– Rates for activities are influenced by the installation cost factor reflecting costs of labour, materials and construction equipment.

These were assumed to be the major influence on the overall cost factor and were split evenly at 40% each.

Equipment costs including the pump turbines, generators, balance of plant, switchyard etc. can be about a quarter of the overall cost estimate. However, the influence of the equipment cost factor on a locational cost factor is less because the supply costs to a port are the same, and the only variable is the transportation costs. Hence a relatively low weighting was applied to equipment costs.

The cost of land and development can be highly variable, environmental offset costs in particular. Using the methodology described in Section 8.1.4, the additional cost for land and development was found to be approximately 6% of the total cost.

[360] GHD 2025 AEMO Pumped Hydro Energy Storage Parameter Review

This results in the estimated cost weighting in Table 8.5.

Table 8.5 Typical weighting of costs for PHES projects

Cost item	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs	Topography
	14%	0%	6%	40%	40%

8.2.3 Combined locational cost factors

The equipment, land and development and installation cost factors for all technologies as listed in Table 8.3 were combined with the topography factors from Table 8.4 using the weighting factors in Table 8.5 to develop an overall locational cost factor for PHES in each of the ISP sub-regions.

For AEMO's modelling, the Locational Cost Factor should be 1.0 for a representative capital city. For this reason, the factors have been adjusted such that the factor for Melbourne is 1.0 by dividing the sum-product of the factors and weightings by the value obtained for Melbourne. The outcomes are summarised in Table 8.6. Refer to GHD's 2025 Report[361] for more detail.

Table 8.6 Locational cost factors for PHES development

Subregion Name	ISP Sub-region	10-hour storage	24-hour storage	48-hour storage	160-hour storage
Northen New South Wales	NNSW	1.04	1.02	0.96	0.93
Central New South Wales	CNSW	1.04	1.01	1.03	0.98
South New South Wales	SNSW	1.13	1.08	1.18	1.08
Sydney, Newcastle, Wollongong	SNW	1.02	1.02	1.02	1.02
Northern Queensland	NQ	1.08	1.01	0.99	0.98
Central Queensland	CQ	1.00	0.99	0.92	1.08
Gladstone Grid	GG	1.01	1.01	1.01	1.01
South Queensland	SQ	0.92	0.99	1.01	0.97
Northern South Australia	NSA	1.03	1.06	1.13	1.03
Central South Australia	CSA	0.96	0.99	0.97	0.97
South East South Australia	SESA	1.00	1.00	1.00	1.00
Tasmania	TAS	1.01	1.01	1.01	1.07
West and North Victoria	WNV	0.98	0.93	1.00	1.01
Greater Melbourne and Geelong	MEL	1.00	1.00	1.00	1.00
South East Victoria	SEV	1.01	1.01	1.01	1.01

[361] GHD 2025 AEMO Pumped Hydro Energy Storage Parameter Review

Appendix A

AEMO GenCost 2025 Excel Spreadsheet

Appendix B

Equipment Cost Factor Region Maps

Paper Size ISO A4

0 90 180 270 360

Kilometers

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

N

GHD

AEMO
Costs and Technical Parameter Review

COST REGION MAPS
QUEENSLAND

Project No. 91-10715
Revision No. A
Date 17/ 08/ 2018

FIGURE 1

G:\91\10715\GIS\Maps\MXD\91-10715_001_Queensland_revA.mxd
Print date: 17 Aug 2018 - 10:59

Data source: GA: populated places (2007); GHD: Buffer Distances (2018); Esri, Garmin, GEBCO, NOAA NGDC, and other contributors. Created by: acjackson

AEMO
Costs and Technical Parameter Review

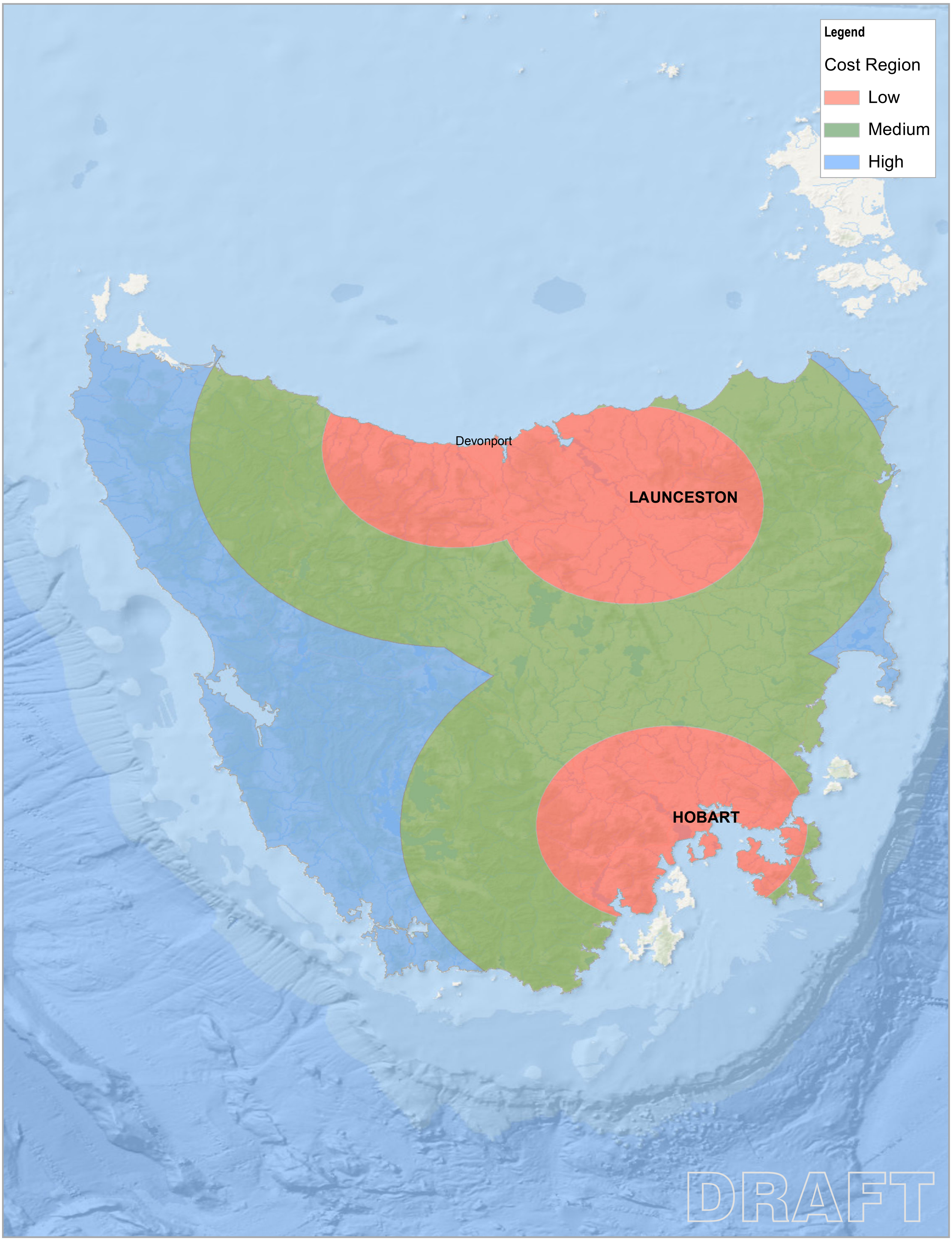
COST REGION MAPS
NEW SOUTH WALES

Project No. 91-10715
Revision No. A
Date 17/ 08/ 2018

FIGURE 2

G:\91\10715\GIS\Maps\MXD\91-10715_002_NewSouthWales_revA.mxd
Print date: 17 Aug 2018 - 10:55

Data source: GA: populated places (2007); GHD: Buffer Distances (2018); Esri, Garmin, GEBCO, NOAA NGDC, and other contributors. Created by: acjackson



Paper Size ISO A4

0 20 40 60 80

Kilometers

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

N

AEMO
Costs and Technical Parameter Review

COST REGION MAPS
TASMANIA

Project No. 91-10715
Revision No. A
Date 17/ 08/ 2018

FIGURE 3

G:\91\10715\GIS\Maps\MXD\91-10715_003_Tasmania_revA.mxd
Print date: 17 Aug 2018 - 10:45

Data source: GA: populated places (2007); GHD: Buffer Distances (2018); Esri, Garmin, GEBCO, NOAA NGDC, and other contributors. Created by: acjackson

Paper Size ISO A4

0 75 150 225 300

Kilometers

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

N

GHD

AEMO
Costs and Technical Parameter Review

COST REGION MAPS
SOUTH AUSTRALIA

Project No. **91-10715**
Revision No. **A**
Date **17/ 08/ 2018**

FIGURE 5

G:\91\10715\GIS\Maps\MXD\91-10715_005_SouthAustralia_revA.mxd
Print date: 17 Aug 2018 - 10:47

Data source: GA: populated places (2007); GHD: Buffer Distances (2018); Esri, Garmin, GEBCO, NOAA NGDC, and other contributors. Created by: acjackson

Paper Size ISO A4

0 50 100 150 200

Kilometers

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

N

AEMO
Costs and Technical Parameter Review

COST REGION MAPS
VICTORIA

Project No. 91-10715
Revision No. A
Date 17/ 08/ 2018

FIGURE 7

G:\91\10715\GIS\Maps\MXD\91-10715_007_Victoria_revA.mxd
Print date: 17 Aug 2018 - 10:51

Data source: GA: populated places (2007); GHD: Buffer Distances (2018); Esri, Garmin, GEBCO, NOAA NGDC, and other contributors. Created by: acjackson

Appendix C

GHD's 2025 Energy Technology Retirement Cost & O&M Estimate Review

2025 Energy Technology Retirement Cost & O&M Estimate Review

Retirement cost estimate and O&M review for existing NEM-connected plants and emerging technologies

Australian Energy Market Operator

15 July 2025

Project name	AEMO 2025 Energy Technology Retirement Cost & O&M Estimate Review						
Document title	2025 Energy Technology Retirement Cost & O&M Estimate Review | Retirement cost estimate and O&M review for existing NEM-connected plants and emerging technologies						
Project number	12666496						
File name	12666496-REP-GHD Advisory-2025 Energy Technology Retirement Cost Review-REV0.docx						
Status Code	Revision	Author	Reviewer		Approved for issue		
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S4	B	Various	G Conway		G Hatch		26/06/25
S4	Rev 0	Various	G Conway	On File	G Hatch	On File	15/07/25

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1. Introduction

The Australian Energy Market Operator (AEMO) requires a revised dataset to support its forecasting and planning functions related to the cost of operation and retirement, including recycling, of existing electricity generation facilities across the National Energy Market (NEM), as well as the retirement and recycling costs associated with emerging electricity generation technologies for use in the 2026 Integrated System Plan (ISP).

This study by GHD provides an update for AEMO on existing retirement, recycling and operations and maintenance (O&M) for the technologies included using reliable and comprehensive data to support its forecasting and planning activities.

This Report is a high-level Report and should be read in this context, in conjunction with the limitations, assumptions and qualifications contained throughout this Report.

The asset types reviewed in this study are separated into two categories, existing NEM-connected coal and gas generation asset types and emerging electricity generation technologies, and are presented below:

Existing NEM-connected asset types:

1. Steam Sub Critical – Coal
2. Steam Super Critical – Coal
3. Open Cycle Gas Turbine (OCGT) – large GT (200MW+)
4. OCGT – Small GT (30MW – 100MW)
5. Closed Cycle Gas Turbine (CCGT) – Gas Turbine (GT)
6. CCGT – Steam Turbine

Emerging energy generation technologies:

1. Biomass
2. Large-scale solar photovoltaic
3. Solar thermal (16- hour storage)
4. Wind (onshore)
5. Wind (offshore)
6. Battery Energy Storage System (BESS) (2-hour storage)
7. BESS (4-hour storage)
8. BESS (8-hour storage)
9. PHES (Pumped Hydro Energy Storage) (10-hour storage)
10. PHES (24-hour storage)
11. PHES (48-hour storage)
12. Electrolyser (Proton Exchange Membrane [PEM])
13. Electrolyser (Alkaline)

The study focuses on the costs of disposal, recycling, and retirement, as well as the estimated retirement duration for each asset type. However, regarding existing NEM-connected coal and gas generation assets, additional information is provided including:

1. Fixed operating and maintenance (O&M)
2. Variable O&M

1.1 Purpose of this Report

This report and accompanying dataset (the Report) provides a high-level summary of the retirement, operational expenditure, and / or recycling costs for a range of established and emerging electricity generation technologies across the National Electricity Market. This Report, including the accompanying dataset, are a high-level updated input data to retirement, operational expenditure, and / or recycling estimates for use in Australian Energy Market Operator forecasting and planning studies.

1.2 Scope

This Report is the first update to retirement costs for AEMO since the GHD Report titled '*AEMO cost and technical parameter review (September 2018)'*[1] for existing power generation assets, and the first to include emerging power generation technologies.

The scope of for this review was based on three main tasks:

3. Development of a draft dataset and accompanying draft Report outlining key updates to AEMO's current set of values for:
   a. Retirement cost estimates for existing NEM connected coal and gas generation plants as outlined in AEMO Draft 2025 Stage 1 Inputs and Assumptions Workbook (2025).
   b. Fixed and Variable Operation & Maintenance cost estimates for existing NEM connected coal and gas generation plants as outlined in AEMO Draft 2025 Stage 1 Inputs and Assumptions Workbook (2025).
   c. Retirement cost estimates (including recycling) for emerging generation technologies as outlined in Section 1 (see list of asset types reviewed).
4. Peer Review Process, including:
   a. Facilitate an industry stakeholder workshop.
   b. Facilitate a public-facing workshop.
   c. Consolidate and include stakeholder feedback into the draft dataset and report where appropriate.
   d. Develop a Consultation Conclusion Report.
5. Prepare Final Dataset and Report.

[1] AEMO cost and technical parameter review, GHD, 2018

1.3 Limitations

This Report: has been prepared by GHD for Australian Energy Market Operator and may only be used and relied on by Australian Energy Market Operator for the purpose agreed between GHD and Australian Energy Market Operator as set out in sections 1.1 and 1.3 of this Report and is not intended for use for any other purpose.

GHD otherwise disclaims responsibility to any person other than Australian Energy Market Operator arising in connection with this Report. This Report must not, without prior written consent of GHD, be used or relied on by any other entity or person other than Australian Energy Market Operator. Any use of, or reliance on, this Report by any third party is at the risk of that party. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this Report were limited to those specifically detailed in the Report and are subject to the scope limitations set out in this Report.

The opinions, conclusions and any recommendations in this Report are based on conditions encountered and information reviewed at the date of preparation of this Report. GHD has no responsibility or obligation to update this Report to account for events or changes occurring subsequent to the date that this Report was prepared.

The opinions, conclusions and any recommendations in this Report are based on assumptions made by GHD described throughout this Report . GHD disclaims liability arising from any of the assumptions being incorrect.

GHD has prepared this Report on the basis of information sourced by, and provided to, GHD (including Government authorities), which GHD has not independently verified or checked. GHD does not accept liability in connection with such unverified information, including errors and omissions in this Report which were caused by errors or omissions in that information.

GHD has prepared the costs estimates set out throughout this Report ("Cost Estimates") using information reasonably available to the GHD employee(s) who prepared this Report; and based on assumptions and judgments made by GHD as detailed in this Report. All cost related information being in real 2025 Australian Dollars for base estimates, with no allowances for escalation or inflation. The Cost Estimate is high-level and is not suitable for budgeting purposes.

The Cost Estimate has been prepared for the purpose of informing Australian Energy Market Operator of current retirement, recycling, and / or operating costs (where applicable) of specific power generation infrastructure types and must not be used for any other purpose.

The Cost Estimate is a preliminary estimate, relevant to Class 5 estimates or Order of Magnitude only. Actual prices, costs and other variables may be different to those used to prepare the Cost Estimate and may change. Unless as otherwise specified in this Report, no detailed quotation has been obtained for actions identified in this Report. GHD does not represent, warrant or guarantee that the projects can or will be undertaken at a cost which is the same or less than the Cost Estimate.

Where estimates of potential costs are provided with an indicated level of confidence, notwithstanding the conservatism of the level of confidence selected as the planning level, there remains a chance that the cost will be greater than the planning estimate, and any funding would not be adequate. The confidence level considered to be most appropriate for planning purposes will vary.

1.4 Abbreviations

Table 1 Abbreviations

Acronym	Definition
AACE	Association for the Advancement of Cost Engineering
AC	Alternating circuit
AEMO	Australian Energy Market Operator
AGIG	Australian Gas and Infrastructure Group
ARENA	Australian Renewable Energy Agency
AUD	Australian Dollar
AUSC	Advanced Ultra-supercritical
BESS	Battery Energy Storage System
BOP	Balance of Plant
CAPEX	Capital Expenditure
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon capture and storage
CFB	Circulating Fluidised Bed
CHP	Combined Heat and Power
CO2	Carbon Dioxide
CST	Concentrated solar thermal
DC	Direct Current
DLE/DLN	Dry Low NOx
EPC	Engineer Procure and Construct
EXR	Exchange Rate
FEED	Front End Engineering and Design
FD	Forced Draft
FGD	Flue Gas Desulfurization
GBP	Great Britain Pound
GST	Goods and Services Tax
GT	Gas Turbine
GW	Gigawatt
HP	High Pressure
HV	High Voltage
HVAC	Heating, Ventilation, and Air Conditioning
ID	Induced Draft
ISP	Integrated System Plan
KOH	Potassium Hydroxide
kPa	Kilopascal
LFP	Lithium Iron Phosphate
LV	Low Voltage
mbgl	Metres below ground level
mm	Millimetre

Acronym	Definition
MPa	Megapascal
MV	Medium Voltage
MW	Megawatt
MWh	Megawatt-hour
NCA	Lithium Nickel Cobalt Aluminium
NEM	National Electricity Market
NER	National Electricity Rules
NMC	Lithium Nickel Manganese Cobalt Oxides
NOx	Nitric Oxide
O&M	Operations and Maintenance
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
OFW	Offshore Wind Farm
OH^-	Hydroxide ion
OPEX	Operational Expenditure
PC	Pulverised coal
PCB	Polychlorinated biphenyl
PEM	Proton Exchange Membrane
PET	Polyethylene Terephthalate
PGM	Pt-Group Metal
PHES	Pumped Hydropower Energy Storage
PHS	Pumped Hydro Storage
PSH	Pumped Storage Hydropower
PSP	Pumped Storage Plant
PV	Photovoltaic
ROV	Remotely Operated Vehicle
rpm	Revolutions per minute
SAT	Single-axis Tracking
SCR	Selective Catalytic Reduction
SOEC	Solid Oxide Electrolyser Cells
SOx	Sulfur Oxide
TES	Thermal Energy Storage
UNSW	University of New South Wales
USC	Ultra-supercritical
USD	United States Dollar
XLPE	Cross-Linked Polyethylene

2. Approach & Methodology

2.1 Approach

The retirement and recycling cost dataset and this Report for existing NEM connected coal and gas generation facilities (Section 3) has been prepared based on scenarios agreed with AEMO and reflective of facilities installed in the NEM.

The agreed scenarios for existing NEM connected coal and gas facilities and emerging technologies have built upon those outlined in the *Aurecon 2024 Energy Technology Cost and Technical Parameter Review (December 2024)* [2] report. The scenarios considered are largely consistent with those presented by Aurecon for consistency and are reflective of existing NEM connected coal and gas technologies, and hypothetical projects representative in 2025 per technology for emerging technologies, with amendments defined where relevant.

Where possible, retirement, recycling and operation and maintenance (O&M) cost estimates were based on:

– GHD’s internal project database including recent industry closure assessments
– Industry publications, credible and reliable publicly available information and published reputable industry databases

This Report examined recent market trends that could impact the retirement and recycling of power generation facilities across different technologies. It considered various factors that may affect the retirement of these technologies. These trends are presented in each section of this Report and were used to develop cost estimates where significant.

It is important to note that Owners costs were not included in the retirement and recycling cost estimates prepared. These costs were outside the scope of the retirement cost estimates prepared in this review as they are unique to individual organisations responsible for decommissioning an asset. In preparing an asset-specific retirement cost estimate, Owners costs would need to be evaluated on an asset case-by-case basis and added to physical retirement cost estimate. Refer to Section 2.3 for the definition of Owners costs in the context of this review.

2.2 Methodology

Retirement estimates

The methodology used for estimating retirement and recycling, including disposal, costs for existing NEM-connected coal and gas generation technologies, and retirement and recycling costs for new technologies, applied the following steps:

1. Review existing AEMO datasets.
2. Define and agree scenarios with AEMO to be included in the review.
3. Undertake review of reputable publicly available information to define relevant market trends with potential to impact retirement estimates.
4. Identify key components of each technology relevant to retirement.
5. Define high-level retirement process.
6. Define assumptions and technology boundaries.
7. Update retirement and recycling cost estimates based on:
    a. GHD internal project information
    b. Generator provided information
    c. Publicly available credible and reliable information

[2] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024

O&M estimates

O&M cost estimates for existing NEM-connected coal and gas generation technologies were prepared using a high-level 'bottom-up' cost estimation methodology to estimate fixed and variable O&M costs. The preparation of these cost estimates considered the following cost drivers based on GHD internal project experience and industry knowledge:

Fixed O&M

– Labour costs
– Routine maintenance costs
– Contractor and consultant costs associated with general operations

Variable O&M

– Consumables costs
– Scheduled term maintenance costs (5 year cycle)
– Long term maintenance costs (half-life refurbishment)

Fuel costs, which represent a material variable O&M cost, have not been included. Note that O&M cost estimates will be subjective for each asset as costs are subject to a wide range of asset and situation specific factors. These factors include, but are not limited to:

– Organisation operating philosophy
– Market prices for consumables
– Competitive market forces for equipment and services such as contractor and consultant fees
– Original Equipment Manufacturer (OEM) recommended maintenance needs
– Asset location
– Insurance premiums

Further assessment to understand O&M costs for assets on an individual basis should be undertaken to refine confidence in cost estimates as needed.

2.3 Key retirement definitions

The table below provides a high-level definition of key terms related to retirement used in this Report. These are general definitions only. Refer to both 'General Assumptions' in Section 2.4 and 'Technology Specific Assumptions' sections in each technology subsection for assumptions guiding the retirement cost estimates provided in this Report.

Table 2 General definitions

Term	Definition
Retirement Cost	Retirement cost is the total cost incurred at the end of life of the asset in order to return the site to an assumed end state. This cost incorporates the cost of decommissioning, demolition, site rehabilitation, and disposal and recycling of materials.
Decommissioning	Decommissioning of an asset is the planned, controlled process of permanently removing an asset from service, ensuring it is made safe, environmentally compliant, and prepared for demolition, repurposing, or site rehabilitation.
Demolition	Demolition refers to the planned and controlled process of deconstructing or destroying physical structures of an asset in preparation for site rehabilitation, redevelopment or return to greenfield.
Rehabilitation	Rehabilitation is the process of restoring a site to a safe, stable, and environmentally compliant condition, consistent

Term	Definition
	with regulatory and contractual requirements and the intended future land use of the site.
Technical Life	The technical life of an asset refers to the typical duration between the initial commercial operation of an asset and its final decommissioning, assuming standard operating conditions and major and minor maintenance.
Disposal Cost	Disposal costs refer to the offsite costs associated with disposal of materials produced through the decommissioning and demolition process, and through the act of rehabilitation (e.g. contaminated soil).
Recycling Costs	Recycling costs include potential savings associated with recycling or on sale of material or components that may be salvaged through the decommissioning process (e.g. steel, copper). This value can be used to offset the cost of retirement cost and contribute a negative cost. In certain circumstances, key components may be required to be recycled, yet recycling incurs a net cost (e.g. PV panels). Such elements will contribute a positive cost. Similarly, in some instances, key components may be sold or repurposed for another project and will contribute toward the retirement cost. The recycling estimates presented in each section of this Report are net recycling costs.
O&M costs	O&M costs are recurring expenses associated with the day-to-day functioning and upkeep of a power generation facility to maintain operations.
Fixed O&M costs	Fixed O&M costs are independent of energy output, including routine maintenance, labour, and consultants / contractor costs.
Variable O&M costs	Variable O&M costs are proportional to the output of a power generation facility including consumables, scheduled term maintenance and long-term maintenance costs. Variable O&M are on a ‘sent-out’ or net basis.
Owner’s costs	Owner’s costs refer to the expenses required to maintain asset operations and incurred directly by the owner as part of business operations. In the context of this Report, Owner’s costs include but are not limited to: – Project planning and management – Land lease costs – Grid connection / utility interface costs – Financing and insurance costs – Corporate governance and business operations (i.e. Human resources, information technology, legal, etc) – Government fees, licences or permit fees, – Taxes and rates These are highly specific to individual companies and assets.
Duration of retirement	The duration of retirement refers to the timeframe required to undertake decommissioning, demolition, and site rehabilitation activities following the cessation of operations. While these stages are applicable across all technologies examined in this report, the scope and intensity of each phase will vary based on the specific characteristics and requirements of the asset. In some instances, these phases may be executed concurrently. For example, rehabilitation of an ash dam may be initiated during the demolition of the associated coal-fired power station.

2.4 General assumptions

The cost estimates presented in this Report have been developed based on the following general, high-level assumptions. While the general theme of retirement is consistent between technologies and the general assumptions are consistent, each technology will have its own set of specific assumptions which guide the retirement estimation process. These technology specific assumptions are presented in each section of the Report.

The general assumptions used to estimate the Retirement cost estimates presented in this Report are:

– Retirement is assumed to be undertaken at the end of technical life of the technology. Except where specifically mentioned (i.e. Coal and Gas technology), revenue up-side from sale of land, or plant and equipment not included. Revenue from scrap salvage is included in the cost estimates.
– Allowance for remediation and rehabilitation of typical levels of contamination per technology type has been included. No substantial contaminated soil or groundwater rehabilitation has been included.
– Sites will be returned to a state for practical use post-retirement according to assumed post-rehabilitation land use. This is defined in the Technology Specific Assumptions per technology type.
– All costs are on the basis of 2025 activity and in real 2025 Australian dollars and are exclusive of GST. No allowances for escalation or inflation have been made.
– Boundaries for the Retirement cost estimates are limited to the power station facility boundary and are focused on the power station technology as defined in each section. Ancillary infrastructure is not included in the cost estimates, with the exception of ash dam infrastructure and water treatment facilities for coal scenarios.
– Any disposal facilities required are assumed to be within a reasonable distance of the project site.
– This Report is focused on cost estimates for Retirement only. Other end of life options including asset repowering or life extension have not been considered.
– Owner’s costs are excluded from Retirement cost estimates.
– Retirement estimates have not considered project contingencies or contingent risks associated with retirement (i.e. risk of schedule delays).
– Site specific regulatory closure obligations for existing assets have not been considered.
– No matters related to State Agreements, or other parties with potential closure obligations relevant to existing assets, has been considered.
– The following have not been considered as part of the preparation of this Report:
  - Climate change
  - Changes to regulations and legislation
  - Existing contractual liabilities for existing assets
  - Technological changes and advances beyond the scenarios described
  - Potential impacts on heritage and cultural artefacts
  - Land tenure agreements for existing assets
  - Any changes to market costs associated with changes in exchange rates and premiums or access associated with availability of contractors and equipment

2.5 Drivers of change in estimates over time

The retirement estimation process was last undertaken by GHD in 2018 for select NEM-connected assets as part of the AEMO *'Costs and Technical Parameter Review'* (GHD, 2018), and 2014 for select emerging technologies considered as part of the '*Fuel and Technology Cost Review*' (Acil Allen, 2014). Retirement considerations were a minor component of the previous reviews, which focused on the technical and economic parameters of each technology to inform AEMO market simulation studies[3]. Since that time, retirement cost estimation for power generation assets has evolved. This has resulted in material changes to assumptions and the estimation process over time, and is largely due to several key drivers, including but not limited to the following:

A more mature understanding of the retirement process

Over time, the industry has gained a deeper and more sophisticated understanding of the complexities involved in asset retirement. This practical experience has improved the accuracy of estimates by capturing the full scope of activities required, from early decommissioning through to demolition and long-term rehabilitation. With clearer scoping, structured work breakdowns, and lessons learned from past projects, estimates are now more robust, consistent, and aligned with real-world conditions.

Current benchmarks

Project information from previous internal studies and current project studies related to retirement has been utilized where available to benchmark cost and time estimates. These reference projects provide insights into the key considerations going into a retirement estimate and enable a first principles approach to estimation, with actual project information to compare estimates for a wide range of established technologies. For novel technologies, such as CST, offshore wind and electrolysers, the estimation process was more challenging as internal and industry reference projects are limited. For those novel technologies, the estimates were still based on a first-principles approach with a defined retirement process and series of assumptions, with benchmarking against industry publications where possible.

Trends in the retirement of assets

Market trends in asset retirement are continually evolving and have been used to define the assumptions and scenarios which underpin the estimates. In some cases, these have materially changed since 2014 and 2018 and have therefore influenced retirement estimates.

Increased demand for used gas turbine and reciprocating engine equipment has resulted in higher resale value for these technologies. This has been reflected in the retirement cost assumptions, with an established secondary market providing a partial offset to overall retirement cost.

Certain technology components, meanwhile, such as PV modules, batteries, and wind turbine blades, are increasingly subject to specialised recycling requirements, contributing to higher retirement cost estimates. As of 2025, recycling markets for these materials remain in early stages of development. While future cost reductions may occur as volumes increase and recycling technologies mature, the timing and extent of such reductions remain uncertain.

Similarly, shifts in thinking around post-retirement infrastructure such as assumptions around the beneficial use of retaining pumped hydro reservoirs has had a material influence on the estimated retirement costs for that type of infrastructure in this Report.

[3] Acil Allen, 'Fuel and Technology Cost Review – Final Report', 2014 -

3. Coal and gas generation technologies

This section details the retirement of and operational expenditure cost estimates for existing NEM-connected coal and gas generation technologies. For the purposes of this review, these technologies have been categorised as:

Coal

– Black Coal Sub-Critical (small & Large with and without CCS)
– Black Coal Super-Critical (small and large with and without CCS)
– Brown Coal Sub-Critical (small and large with and without CCS)

Gas

– OCGT – Small (aero-derivative & industrial without CCS)
– OCGT – Large (aero-derivative & industrial without CCS)
– CCGT without CCS
– CCGT with CCS
– CCS has not been used in the past for OCGT or CCGT plants. CO2 content in most OCGT plants is much lower than for coal plants and therefore costly to extract.

The definition of each technology type is defined in the following sub-sections.

3.1 Coal generation

Coal fired power plants are currently the dominant source of electricity generation in Australia, providing 46% of electricity generation for the NEM in 2024/2025[4]. In the NEM there are approximately 21,500 MW of coal fired units installed across all coal power stations in QLD, NSW and VIC. The unit sizes often installed in multiples range from 280 MW to 720 MW[5] and use a range of coal types from low grade brown coal through to black coal[6]. Coal-fired power plants contribute inertia and system strength to a network. They need continuous operation due to slow and limited turndown and are generally used for baseload power generation.

Coal fired (thermal) power plants operate by burning coal in a large industrial boiler to generate high pressure, high temperature steam. High pressure steam from the boiler is passed through the steam turbine generator where the steam is expanded to drive the turbine linked to a generator to produce the electricity. This process is based on the thermodynamic Rankine cycle.

Most coal fired power plants are typically classified as sub-critical[7] with several classified as super-critical[8]. Recent development around the world has seen growth of ultra-super critical[9] and advanced ultra-supercritical plants depending on the steam temperature and pressure. Over time advancements in the construction materials have permitted higher steam pressures and temperatures leading to increased plant efficiencies and overall generation unit capacity[10].

[4] Source: “www.nemondemand.com.au”
[5] Eraring Power Station unit size
[6] Source: “https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information”
[7] Sub- Critical pressures are steam pressures between 60 and 160 bar and temperatures between 440-550 deg C
[8] Super-critical pressures are steam pressures between 180 and 220 bar and temperatures beyond 580-620 deg C.
[9] Ultra-super critical pressures are steam pressures of beyond 240 Bar and steam temperatures beyond 700 deg C.
[10] Ultra super-critical thermal power plant material advancement: A review, Dheeraj Shankarrao Bhiogade, Science Direct, Vol 3 September 2023, 100024

3.1.1 Technology overview

The coal fired power stations installed on the NEM utilise either sub-critical or super-critical pulverised coal (PC) technology, which is an established, proven technology used for power generation throughout the world.

The latest super-critical coal fired units installed in Australia can produce super-critical steam conditions in the order of 24 MPa and 566°C and typically used with unit sizes of about 425 MW. Internationally, more recent coal fired units have been installed with ever increasing steam temperature and pressure conditions.

Current OEMs are proposing super-critical units in line with the following:

– Ultra-supercritical (USC), with main steam conditions in the order of 27 MPa and 600°C
– Advanced ultra-supercritical (AUSC), with main steam conditions in the order of 33 MPa and 660°C.
– Ultra-supercritical coal fired units are typically installed with capacities of 600 MW – 1,000 MW each.

An advanced ultra-supercritical power station with the above main steam conditions is yet to be constructed internationally, however, are currently being proposed by a number of OEMs globally. No ultra-super-critical or advanced ultra-super-critical coal fired units are installed or planned in Australia at present.

CCS has not been adopted at any power station at a commercial scale. There have been a number of pilot plants, but none have been developed further. Sub-critical coal technology produces the most CO_2 emission as a result of its lower efficiency. Super-critical coal power stations have generally 2% better efficiency and therefore produce less CO_2/MWh than sub-critical power stations. Ultra super-critical is a technology having the highest plant efficiency of all coal technologies. Efficiency for ultra-supercritical technology is ~ 2% better than for Supercritical and therefore has the lowest CO_2 emissions of all the coal burning technologies in a Rankine Cycle.

Less than 10 coal fired power stations overseas have added a CCS plant but mainly to redirect the CO_2 captured for oil production enhancement in oil wells (not strictly sequestration).

3.1.2 Recent trends

The last coal fired power station to be installed in Australia was Kogan Creek Power Station in Queensland which was commissioned in 2007. Since then, there has been very little focus on further coal fired development in Australia.

In March 2017, Hazelwood Power Station ceased operation in Victoria and AGL's Liddell Power Station in NSW was retired in April 2023. Vales Point Power Station in NSW was to cease operation in 2029, but closure has been pushed back to 2033. More recently, alternative generation technologies have become more prevalent with the energy transition towards net zero, focussed on adopting non-coal technologies for replacing lost capacity with planned coal fired plant closures. Some existing coal fired plants have considered a fuel switch from coal for potential repurposing of the generation plant.

Internationally, particularly in Asia, there has been extensive development of new large coal fired power stations to provide for growing electricity demand (e.g. Van Phong 1 Coal Fired Power Plant, 2 x 660 MW in Vietnam has achieved commercial operation in March 2024; Vung Ang II Thermal Power Plant, 2 x 665 MW in Vietnam is expected to be operational in the 3rd quarter 2025). These plants are commonly being installed utilising super-critical or ultra-supercritical steam conditions which offer improved plant efficiencies and reduced whole of life costs.

However, government policies in many countries in Asia have recently slowed the growth of coal fired stations baring already approved power station developments, investors are favouring alternative renewable generation and have shown less appetite for investment in new coal fired power station development.

In Australia, the only coal fired development in progress is understood to be the Collinsville coal fired power station proposed by Shine Energy[11] (3 x 315 MW totalling 1,000 MW). This project has completed the definitive feasibility

[11] www.shineenergy.com.au

stage 1 and is believed to be at feasibility stage 2. The company website suggests construction duration will be 3 years and given that the stage 2 feasibility study is expected to be completed by the end of 2025, the plant is not likely to be commissioned until the end of 2029.

In recent years, there has been a significant retreat regarding development activities relating to coal fired power plants as existing assets near end-of-life. There are fewer OEMs that are willing to offer coal fired power plant and equipment for coal fired power plants in Australia.

The following sub-sections present cases for practical and hypothetical retirement based on typical NEM-connected coal technologies, both sub-critical and super-critical.

3.1.3 Black coal (sub-critical)

The following tables outline the technical configuration for practical and hypothetical projects to inform retirement of sub-critical technologies using black coal as a fuel.

The sub-critical case generation technology has been selected based on typical size units that could be found in the NEM (280 MW, 340, MW, 350 MW, 400 MW, 660 MW, 700 MW generation unit capacity)

The hypothetical retirement is based on what is plausible for a sub-critical coal-fired power station in the NEM by 2025[12], considering typical options and current trends.

Examples of NEM connected black coal sub-critical power stations the size mentioned include:

– Gladstone PS Units (280MW).
– Bayswater PS Units (660MW).
– Vales Point PS units (660MW).
– Eraring PS units (720MW).

[12] NEM April 2025 Generation Information, AEMO, 2025

Retirement scenario

The following table outlines the configuration of typical Australian coal power stations for sub-critical coal technology.

Table 3 Retirement scenario configuration – black coal sub-critical

Item	Unit	Small w/o CCS	Small with CCS[13]	Large w/o CCS	Large with CCS[14]	Comment
Technology		Sub-critical (Black coal)	Sub-critical (Black coal)	Sub-critical (Black coal)	Sub-critical (Black coal)	With mechanical draft cooling tower.
Carbon capture and storage		No	Yes	No	Yes	90% CCS capture efficiency assumed. SCR and FGD included with both options.
Make model		Western OEM	Western OEM	Western OEM	Western OEM	Western includes Japanese or Korean OEMs
Unit size (nominal)	MW	350	350	660	660	ISO / nameplate rating.
Number of units		1	1	1	1	
Steam Pressures (Main / Reheat)	bar	196 / 48	196 / 48	193 / 47	193 / 47	
Steam Temperatures (Main / Reheat)	°C	563 / 358	563 / 358	562 / 354	562 / 354	
Condenser pressure	kPa abs	4.8	4.8	4.8	4.8	

O&M estimates

The following table outlines fixed and variable O&M cost estimate data for the sub-critical coal technology outlined above.

Table 4 O&M estimate – black coal sub-critical

Item	Unit	Small w/out CCS	Small with CCS	Large w/out CCS	Large with CCS	Comment
Fixed O&M Cost	$ / MW (Net)	38,000	65,000	28,000	46,000	Based on preparation of a high-level bottom-up estimate
Variable O&M Cost	$ / MWh (Net)	7	18	8	18	Based on preparation of a high-level bottom-up estimate

[13] 90% capture efficiency
[14] 50% capture efficiency

3.1.4 Black coal (super-critical)

Retirement scenario

The following table outlines coal power stations configuration for super-critical coal technology.

Examples of NEM connected Black coal super-critical power stations include:

– Millmerran PS units (400MW)
– Kogan Creek PS unit (750MW)

Table 5 Retirement scenario configuration – black super-critical

Item	Unit	Small without CCS	Small with CCS[15]	Large without CCS	Large with CCS[15]	Comment
Technology	-	Super-critical (Black coal)	Super-critical (Black coal)	Super-critical (Black coal)	Super-critical (Black coal)	With mechanical draft cooling tower.
Carbon capture and storage	-	No	Yes	No	Yes	90% CCS capture efficiency assumed. SCR and FGD included with both options.
Make model	-	Western OEM	Western OEM	Western OEM	Western OEM	Western includes Japanese or Korean OEMs
Unit size (nominal)	MW	400	400	700	700	ISO / nameplate rating.
Number of units	-	1	1	1	1	-
Steam Pressures (Main / Reheat)	bar	309 / 75	309 / 75	305 / 74	305 / 74	-
Steam Temperatures (Main / Reheat)	°C	603 / 382	603 / 381	602 / 378	602 / 378	-
Condenser pressure	kPa abs	4.8	4.8	4.8	4.8	-

[15] 90% capture efficiency

O&M estimates

Table 6 presents the fixed and variable O&M cost estimates for black coal super-critical technology.

Table 6 O&M estimates – black coal super-critical

Item	Unit	Small w/out CCS	Small with CCS	Large w/out CCS	Large with CCS	Comment
Fixed O&M Cost	$ / MW (Net)	49,000	72,000	52,000	72,000	Based on preparation of a high-level bottom-up estimate
Variable O&M Cost	$ / MWh (Net sent out)	8	18	8	18	Based on preparation of a high-level bottom-up estimate

3.1.5 Brown coal (sub-critical)

The following table outlines coal power stations configuration and performance for Brown Coal sub-critical technology.

Typical NEM Power stations are:

- Yallourn PS units (350MW)
- Loy Yang A & B units (~580MW)

Retirement scenario

The following table outlines coal power stations configuration for brown coal sub-critical coal technology.

Table 7 Retirement scenario configuration – brown coal sub-critical

Item	Unit	Small w/o CCS	Small with CCS[16]	Large w/o CCS	Large with CCS[17]	Comment
Technology	-	Sub-critical (Brown coal)	Sub-critical (Brown coal)	Sub-critical (Brown coal)	Sub-critical (Brown coal)	With mechanical draft cooling tower.
Carbon capture and storage	-	No	Yes	No	Yes	90% CCS capture efficiency assumed. SCR and FGD included with both options.
Make model	-	Western OEM	Western OEM	Western OEM	Western OEM	Western includes Japanese or Korean OEMs
Unit size (nominal)	MW	350	350	580	580	ISO / nameplate rating.
Number of units	-	1	1	1	1	-
Steam Pressures (Main / Reheat)	MPa	196 / 48	196 / 48	196 / 48	196 / 48	-
Steam Temperatures (Main / Reheat)	°C	563 / 357	563 / 357	562 / 354	562 / 354	-
Condenser pressure	kPa abs	4.8	4.8	4.8	4.8	-

[16] 90% capture efficiency
[17] 50% capture efficiency

O&M estimates

The following table outlines fixed and variable O&M cost estimate data for brown coal sub-critical technology.

Table 8 O&M estimate – brown coal sub-critical

Item	Unit	Small w/out CCS	Small with CCS	Large w/o CCS	Large with CCS	Comment
Fixed O&M Cost	$ / MW (Net)	45,000	78,000	63,000	88,000	Based on preparation of a high-level bottom-up estimate
Variable O&M Cost	$ / MWh (Net)	8	19	8	19	Based on preparation of a high-level bottom-up estimate

3.1.6 Cost estimates

Retirement key assumptions

The following high level key assumptions were made in consideration of retirement of coal fired power station plants (for both small and large power plants as well as sub-critical and supercritical).

- The cost basis is expected to be to a AACE Class 5 level.
- Removal to underside of hardstand areas/slabs, significant solid structures (e.g. stack footings) that extend beyond underside will also remain in-situ.
- Significant solid structures that remain in-situ are to be made flush with the surface.
- Large cooling water pipes (steel or concrete) are removed or filled where relevant.
- Other than treatment of sub-surface or at surface features noted above foundations removed to 1.5 metres below ground level (mbgl).
- Backfill voids with crushed concrete (secured at site) (<100 millimetres (mm) diameter) to ground level
- Owners' costs are not included.
- Cap and contain strategy (e.g. no material off-site).
- All capping material, clay and topsoil won on-site.
- End land use will be brownfield for industrial use.
- Typical CCS components that will be demolished are:
  - Gas Cooler.
  - Absorber.
  - CO_2 stripping tower.
  - Solvent pumps.
  - Reheater.
  - CO_2 compressors.
  - Knockout drum.
  - Heat exchangers (for water and solvent).
  - Flue gas Ducting.
  - Processed flue gas stack.
  - Piping & valves (for water and solvent process.
  - Electrical control room.
  - Solvent tanks and pumps.
  - All associated roadways.
  - All lighting and LV power.

Retirement process overview

The following outlines the general process considered for retirement of a coal fired power station (sub-critical and supercritical):

- Denergise all energy sources present especially electrical and potential.
- Remove hazardous materials present, including:
  - asbestos waste based on site asbestos register with disposal to on-site asbestos containment cell.
  - polychlorinated biphenyl (PCB) rectifier transformers, assuming PCB containing equipment is removed from site prior to closure.
- Charge fell of chimney and cooling tower (where relevant) infrastructure to ground level and remove concrete foundations consistent with removal requirements noted above.
- Remove cooling water pumps, piping equipment and infrastructure and pits and concrete foundations.
- Remove equipment and supporting infrastructure from boilers including coal mills, ducting associated with boiler feed system including coal bunker and pulverizes, coal bunkers, coal delivery and weighing conveyors, soot-blowers, furnace water cannons, auxiliary firing system, bunker gates, burners, firing controls and operating systems, forced draft (FD) and induced draft (ID) fans, fabric filter plant, ducting between boilers and stacks, etc.
- Dismantle and remove steam turbines along with concrete foundations consistent with removal requirements noted above.
- Dismantle and demolish boiler superstructure, including sorting and cut-up steelwork and piping to manageable pieces and separate for salvage.
- Remove condensers from the turbine plant, along with all feed heaters, boiler feed pumps, controls, interconnecting piping for feedwater and steam (HP/MP/LP).
- Remove overhead lifting equipment from turbine hall and demolish turbine hall to slab level, and remove concrete foundations consistent with removal requirements noted above.
- Dismantle conveyors from coal crushing / storage plant and remove support structure and foundations consistent with removal requirements noted above.
- Demolish ash plant and remove concrete foundations, backfill to ground level with crushed concrete.
- Remove and dispose high voltage (HV) transformers, demolish bunded area and remove foundations consistent with removal requirements noted above.
- Dismantle clarification plant including removal of pumps, tanks, piping, etc and demolish, remove water from holding tanks and demolish, remove foundations consistent with removal requirements noted above.
- Dismantle and remove all water and fuel storage tanks and prepare for steel salvage remove foundations consistent with removal requirements noted above.
- Demolish administration building to slab and remove foundations consistent with removal requirements noted above.
- Remove parking lot and access roads consistent with removal requirements noted above.
- Dismantle all supply and return water pipes for the ash delivery system remove foundations consistent with removal requirements noted above.
- Rehabilitate ash dams according to the required approved process.
- Level the ash dam and remove any contaminated soil.
- Place a minimum of 150mm thick layer of soil across the ash dam.
- Test the soil to establish what needs to be added to the soil to promote plant growth.
- Sow seeds according to the agreed plantation requirement.
- Add fertiliser across the ash dam to promote plant growth.
- Apply dust suppressant to the ash dam.
- Remove pump station, towers, dry coal storage bunker and associated conveyors and remove foundations consistent with removal requirements noted above.

– Remove all coal unloading plant, bins and transfer infrastructure and remove foundations consistent with removal requirements noted above.

Retirement estimate

Retirement estimates for black coal cycle power stations and brown coal cycle power stations that are reflective of NEM based generating plants are outlined in Table 9, Table 10, and Table 11 below.

Table 9 Retirement estimate – black coal sub-critical

	Small w/o CCS	Small with CCS	Large w/o CCS	Large with CCS
Decommissioning & Demolition Costs ($/MW)	$126,000	$203,000	$117,000	$187,000
Rehabilitation Costs ($/MW)	$110,000	$176,000	$119,000	$191,000
Disposal Costs ($/MW)	$51,000	$82,000	$50,000	$80,000
Recycling Cost ($/MW)	($32,000)	($42,000)	($32,000)	($38,000)
Retirement Costs ($/MW)	**$255,000**	**$419,000**	**$254,000**	**$420,000**

Table 10 Retirement estimate – black coal super-critical

	Small w/o CCS	Small with CCS	Large w/o CCS	Large with CCS
Decommissioning & Demolition Costs ($/MW)	$126,000	$200,000	$117,000	$186,000
Rehabilitation Costs ($/MW)	$110,000	$174,000	$119,000	$189,000
Disposal Costs ($/MW)	$51,000	$81,000	$50,000	$80,000
Recycling Costs ($/MW)	($37,000)	($50,000)	($39,000)	($55,000)
Retirement Costs ($/MW)	**$250,000**	**$405,000**	**$247,000**	**$400,000**

Table 11 Retirement estimate – brown coal sub-critical

	Small w/o CCS	Small with CCS	Large w/o CCS	Large with CCS
Decommissioning & Demolition Costs ($/MW)	$168,000	$202,000	$164,000	$213,000
Rehabilitation Costs ($/MW)	$146,000	$206,000	$159,000	$206,000
Disposal Costs ($/MW)	$68,000	$87,000	$69,000	$90,000
Recycling Costs ($/MW)	($32,000)	($32,000)	($37,000)	($37,000)
Retirement Costs ($/MW)	**$350,000**	**$463,000**	**$355,000**	**$472,000**

Duration of retirement

The table below provides an estimate for the relevant durations, pertaining the process for retirement, for sub-critical coal power station technology.

Table 12 Duration periods – coal

Activity	Duration (weeks / years) Small Power Stations	Duration (weeks / years) Large Power Stations
Decommissioning	52 / 1	52 / 1
Demolition	156 / 3	260 / 5
Rehabilitation	156 / 3	260 / 5

3.2 Gas generation

Gas turbines are one of the most widely used power generation technologies today. The technology is well proven and is used in both open-cycle gas turbine (OCGT) and combined-cycle gas turbine (CCGT) configurations. Gas turbines are classified into two main categories – aero-derivatives and industrial turbines. Both find applications in the power generation industry, although for baseload applications, industrial gas turbines are preferred. Conversely, for peaking applications, the aero-derivative is more suitable primarily due to its faster start up time. Within the industrial turbines class, gas turbines are further classified as E – class, F – class and H (G/J) – class turbines. This classification depends on their development generation and the associated advancement in size and efficiencies. Gas turbines can operate on natural gas, hydrogen, and liquid fuel, as well as blends of different fuels.

Gas turbines utilize synchronous generators, which provide relatively high fault current contribution in comparison to other technologies that do not use rotating generators and accordingly can support network strength. Synchronous condenser mode operation using the generator is also an option able to be offered for gas turbines, depending on OEM, to provide additional network system strength when the gas turbine is not in operation. Gas turbines currently provide high rotating inertia to the NEM which is a valuable feature that increases the NEM frequency stability.

3.2.1 Technology overview

OCGT

An OCGT plant consists of a gas turbine connected to an electrical generator via a shaft. A gearbox may be required depending on the revolutions per minute (rpm) of the gas turbine and the grid frequency. The number of gas turbines deployed in an OCGT plant will depend mainly on the output and redundancy levels required. OCGT plants are typically used to meet peak demand. Both industrial and aero-derivative gas turbines can be used for peaking applications. However, aero-derivatives have some advantages that make them more suitable for peaking applications, including:

- Better start-up time.
- Operational flexibility i.e. quick ramp up and load change capability.
- No penalties on O&M for normal operations (mid-merit) i.e. only increased maintenance requirements for high number of starts in peaking mode.

Irrespective of the benefits of aeroderivative gas turbines, industrial gas turbines have also been widely used in OCGT mode. Traditionally, E or D class machines are used in OCGT mode. Occasionally F or H class machines are used in OCGT applications. Examples of F class machines used in OCGT configuration in Australia include:

- Mortlake Power Station (operational).
- Tallawarra B Power Station (operational).
- Kurri Kurri Power Station (under construction).

Ultimately, the choice of gas turbine will depend on many factors including the operating regime of the plant, size, and more importantly, life cycle cost.

CCGT

A CCGT consists of a gas turbine/generator with the exhaust connected to a heat recovery steam generator that produces high pressure steam to drive a condensing steam turbine generator. The number of gas turbines deployed in a CCGT plant will depend on the output required and the redundancy level needed. CCGT plants are typically used to meet base load or mid-merit loads. Typical CCGTs installed in the NEM are:

- Tallawarra A (NSW).
- Tamar Valley CCGT (Tasmania).
- Townsville 242MW CCGT.

3.2.2 Recent trends

The growing deployment of renewable energy generation has opened opportunities for capacity firming solutions, with gas-fired power generation being a key component. In this market, Open Cycle Gas Turbines (OCGT) and reciprocating engines are important competitors.

Advancements in gas turbine technology are emphasising low-emission solutions, including the integration of hydrogen, either through blending or complete hydrogen combustion, as well as other renewable fuels such as biomethane. It is anticipated that all new gas turbine projects will incorporate provisions and capabilities for hydrogen blending and eventual conversion to hydrogen combustion as the hydrogen supply becomes more accessible.

Most gas turbines currently have the ability to operate with a percentage of hydrogen in the fuel mix (20-35% of Hydrogen by Volume). A typical blend percentage of around 30% is offered by most OEMs (depending on the unit), whilst some units can accept very high percentages of hydrogen in the fuel (95%+). Currently, few gas turbines can operate on 100% hydrogen (with diffusion combustion system and diluent injection). This is expected to change dramatically by 2030 with newly designed micro/multi-nozzle combustion systems being developed, tested, and implemented to cater for hydrogen..

Hydrogen supply would be either via gas network as a blend or could be via dedicated renewable hydrogen supply from an electrolysis plant. Hydrogen blending in Australia's gas networks is expected to result in open cycle gas turbine plants using a hydrogen-natural gas mix.

Current trends in Australia have included development of a larger gas turbine projects with a lower hydrogen blend percentage based on their current capability for hydrogen operation, or with a smaller aero-derivative gas turbine with a higher hydrogen blend within current capabilities. The blend percentage will also be determined by the supply of hydrogen and blend design capabilities in existing or new gas pipelines adopted.

Alternatively, a hydrogen ready gas turbine plant could be supplied from a dedicated hydrogen electrolysis plant using renewable energy supply and blended with a natural gas pipeline supply to the site. In this case, OCGT plant capacity would be based on hydrogen production from a suitable sized electrolysis plant and operated in peaking duty using hydrogen supply with storage to meet the hydrogen demand.

Depending on the hydrogen percentage, modifications to the gas turbine may range from updating controls and fuel nozzles to installing a new combustion system with updated piping, valves, safety features, and detection systems. Retirement costs will be higher for plants using more than 30-40% hydrogen compared to those using only natural gas.

3.2.3 OCGT

Retirement scenario

The following tables outline the technical parameters for the hypothetical projects (multiple small and large aeroderivative Dry Low NOx (DLN) gas turbines using 35% hydrogen blend with natural gas (based on current capability) and a small and large gas turbine using a 5-10% hydrogen blend) using natural gas, both projects with liquid fuel (e.g. diesel) back up. The hypothetical project has been selected based on what is envisaged as plausible projects for development in the NEM in 2025 given the above discussion on typical options and current trends

Table 13 Retirement scenario configuration – OCGT

Item	Small Aero derivative	Large Aero derivative	Small Industrial	Large Industrial	Comment
Make model	LM2500 (GE)	LM6000 (GE)	SGT-800 (Siemens)	GE 9F.03	Small GTs − Typical model planned in Australian project (LM2500), assumes Dry Low NOx combustion system for NOx emission control with hydrogen blending. Larger LM6000 PC/PG unit with SAC combustion system is typical for NOx control. Small GT – is a typical small GT Large GT − Smallest F-Class unit available
Unit size (MW nominal)	34	48	58	268	% Output derate for 35% hydrogen to be confirmed with OEM for small GT. No derate considered. ISO / nameplate rating, GT Pro. Performance on natural gas
Number of units	6	4	4	1	

O&M estimates

The following table provides fixed and variable O&M cost estimate for the defined OCGT scenario.

Table 14 O&M estimate – OCGT[18]

Item	Unit	Small Aero derivative	Large Aero derivative	Small Industrial	Large Industrial	Comment
Fixed O&M Cost	$ / MW (Net)	28,000	31,000	30,000	27,000	Based on preparation of a high-level bottom-up estimate
Variable O&M Cost	$ / MWh (Net)	9	10	10	12	Based on preparation of a high-level bottom-up estimate

[18] Based on 20% capacity factor

3.2.4 CCGT

Retirement scenario

Table 15 outlines the configuration for a typical NEM-connected CCGT technologies (W/O CCS). There are no CCGT with CCS currently installed in the NEM in Australia. The retirement scenarios for CCGT with CCS (with 90% and 50% capture) are hypothetical.

Table 15 Retirement scenario configuration – CCGT

Item	Unit	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
Technology		CCGT	CCGT	CCGT	With mechanical draft cooling tower.
Carbon capture and storage		No	Yes	Yes	
Make model		GE 9F.03	GE 9F.03	GE 9F.03	Smallest model available selected.
Unit sizes(nominal)	MW	380 (262+118)	352 (262+90)	365 (262+103)	ISO / nameplate rating.
Net Output	MW	371	319	338	
Number of units		1 GT + 1 ST	1 GT + 1 ST	1 GT + 1 ST	HP pressure – 165 bar HP temperature – 582°C Reheat temperature – 567°C

O&M estimates

The following table provides fixed and variable O&M cost estimate for the defined CCGT scenarios.

Table 16 O&M estimates – CCGT

Item	Unit	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
Fixed O&M Cost	$ / MW (Net)	73,000	142,000	119,000	Based on preparation of a high-level bottom-up estimate
Variable O&M Cost	$ / MWh (Net)	11	16	15	Based on preparation of a high-level bottom-up estimate

3.2.5 Cost estimates

Retirement key assumptions

The following assumptions have been made for gas power station technology (for both small and large power plants).

– The cost basis is expected to be to a AACE Class 5 level.
– Removal to underside of hardstand areas/slabs, significant solid structures (e.g. stack footings) that extend beyond underside will also remain in-situ.
– Significant solid structures that remain in-situ are to be made flush with the surface.
– Large cooling water pipes (steel or concrete) are removed or filled where relevant.
– Other than treatment of sub-surface or at surface features noted above foundations removed to 1.5 metres below ground level (mbgl).
– Backfill voids with crushed concrete (secured at site) (<100 millimetres (mm) diameter) to ground level.
– Owners' costs are not included.
– Cap and contain strategy (e.g. no material off-site).
– All capping material, clay and topsoil won on-site.
– End land use will be brownfield for industrial use.
– CCS assumptions are as per CCS in Coal fired power plants (same process but bigger because %CO2 in flue gas is smaller than in coal flue gas.

Retirement process overview

The retirement of OCGT and CCGT technology will (at a high level) include:

– Remove site asbestos waste based on site asbestos register with disposal to on-site asbestos cell.
– Removal of remaining polychlorinated biphenyl (PCB) rectifier transformers, assuming PCB containing equipment is removed from site prior to closure.
– Discharge water from cooling tower units to ground level and remove concrete foundations.
– Remove pumps, piping, and concrete foundations from cooling water pump pits.
– Dismantle and remove gas turbines (and steam turbines for CCGT) for disposal and sale and remove concrete foundations.
– Demolish turbine hall (CCGT only) to slab level and remove foundations.
– Remove and dispose high voltage (HV) transformers, demolish bunded area and remove foundations.
– Dismantle and remove all water and fuel storage tanks and prepare for steel salvage.
– Fell charge administration building to slab and remove foundations.
– Remove parking lot and access road slabs.
– Dismantle all supply and return water pipes for the ash delivery system.
– Demolish remaining buildings to slab and remove foundations.

Retirement estimates

Retirement costs for OCGT technology scenarios (small & large Aeroderivative and small & large Industrial gas turbines) reflective of NEM-connected gas generating plants are outlined in Table 17.

Table 17 Retirement estimate – OCGT

	Small Aero	Large Aero	Small Industrial	Large Industrial
Decommissioning & Demolition Costs ($/MW)	$20,500	$20,500	$18,500	$22,000
Rehabilitation Costs ($/MW)	$27,000	$27,000	$24,500	$26,000
Disposal Costs ($/MW)	$7,500	$7,500	$7,000	$7,500
Recycling Costs ($/MW)	($24,000)	($18,000)	($12,000)	($18,500)
Retirement Costs ($/MW)	**$31,000**	**$37,000**	**$38,000**	**$37,000**

Table 18 presents retirement cost estimates for CCGT technology scenarios (CCGT with and without CCS) reflective of NEM-connected CCGT facilities.

Table 18 Retirement estimate – CCGT

	CCGT (no CCS)	CCGT (with CCS, 90% capture)	CCGT (with CCS, 50% capture)
Decommissioning & Demolition Costs ($/MW)	$52,500	$60,500	$57,000
Rehabilitation Costs ($/MW)	$58,500	$67,000	$64,000
Disposal Costs ($/MW)	$17,500	$20,000	$19,000
Recycling Costs ($/MW)	($23,000)	($26,500)	($24,500)
Retirement Cost ($/MW)	**$105,500**	**$121,000**	**$115,500**

Duration of retirement

Table 19 below provides an estimate for the relevant approximate durations, pertaining to the process for retirement, for OCGT (small and large Aeroderivative and Industrial) technologies.

Table 19 Duration periods – OCGT

Activity	Duration (weeks / years) Small Aero (6xLM2500)	Duration (weeks / years) Large Aero (4xLM6000)	Duration (weeks / years) Small Industrial (4xSTG800)	Duration (weeks / years) Large Industrial (1xGE9F.03)
Decommissioning	26 / 0.5	26 / 0.5	26 / 0.5	35 / 0.7
Demolition & Dismantling	52 / 1	52 / 1	52 /1	52 / 1
Rehabilitation	130 / 2.5	130 / 2.5	130 / 2.5	156 / 3

Table 20 below provides an estimate for the relevant approximate durations, pertaining to the process for retirement, for CCGT technologies.

Table 20 Duration periods – CCGT

Activity	Duration (weeks / years) (GE 9F.03)	Duration (weeks / years) (GE 9F.03 with CCS 90% capture)	Duration (weeks / years) (GE 9F.03 with CCS 50% capture)
Decommissioning	42 / 0.8	52 / 1	52 / 1
Demolition & Dismantling	52 / 1	78 / 1.5	78 / 1.5
Rehabilitation	156 / 3	208 / 4	208 / 4

3.3 Reciprocating engines

Reciprocating engines, also known as piston engines, convert pressure into rotational motion using pistons. Their application spans backup and distributed power generation, remote and off-grid energy, industrial and mining operations, marine and agricultural machinery. The technology is advantageous for its reliability and flexibility with modular and scalable designs. Reciprocating engine generators range in capacity from 2 kW to 20 MW, although for grid applications they are at the upper end of the range.

3.3.1 Technology overview

Reciprocating engines are large-scale internal combustion engines and represent a widely recognized technology deployed in various applications within the NEM. These engines are generally classified by their speed, stroke, configuration, and type of ignition/fuel, and are typically paired with a generator on the same base frame for power generation purposes. Reciprocating engines use synchronous generators to produce alternating current and support system strength of the NEM.

Reciprocating engines for power generation are typically modular in nature and are comprised of:

- Core engine and generator sets.
- Fuel and cooling infrastructure.
- Electrical protection and control systems.
- Emission and environmental control components.
- Structural and support facilities such as stack structures and fuel tanks.

Reciprocating engines have various uses in a network due to their ability to provide fast frequency response, spinning reserve, and ramp rate support as they are highly dispatchable with short start times compared to other synchronous generators. Uses include:

- Grid-firming and peaking plants to support renewables.
- Providing black start capability.
- Hybrid power stations.
- Micro-grids and/or islanded systems.

They can operate on natural gas, diesel, duel-fuel, biofuel, and hydrogen when blended. Grid connected reciprocating engines are typically medium-speed engines, which operate between 500 – 1000 revolutions per minute (RPM). High-speed engines with greater than 1000 RPM are more common in backup applications as they are typically less efficient with a shorter life. The modular nature of reciprocating engines allows for multiple engines to be installed in parallel for scalability and to provide redundancy, with the ability to take individual units offline without significantly compromising full capacity.

Reciprocating engines can operate across a wide load range, with high load typically defined as above 80–90% of rated capacity and low load as below 50%. High-load operation is generally associated with peaking duty, dispatchable generation during periods of high demand, or continuous operation in baseload or backup roles. Low-load operation may be used to provide system support services such as frequency control or spinning reserve.

3.3.2 Recent trends

Reciprocating engines are a mature technology with well-established market characteristics that influence retirement. The technology's maturity is reflected in its stable operational profile, with no material performance improvements or technological developments anticipated over time. This stability provides operators with predictable asset lifecycles and maintenance requirements, facilitating long-term planning for retirement and replacement strategies.

The retirement process for reciprocating engines mirrors that of conventional gas engines, characterized by relatively straightforward decommissioning procedures and robust secondary markets. The strong resale market for these assets is supported by the robust growth in the reciprocating engine market, driven by rising demand for reliable power and increased infrastructure development. This continued market demand stems from their standardized components, widespread availability of technical resources, and applications across various sectors.

Current market offerings encompass a wide range of sizes and capacity factors, enabling deployment across diverse applications from small-scale distributed generation to larger utility-scale installations. A notable example of a NEM-connected gas fired reciprocating engine asset is the AGL Energy's 210 MW Barker Inlet Power Station (BIPS).

Natural gas-fired reciprocating engines are being deployed as a complementary technology more frequently to balance renewables off-grid, as they address grid stability challenges from intermittent renewable capacity, with gas turbines a more frequent option in the NEM. Their operational flexibility enables deployment as peaking stations during high demand periods or as synchronous condensers for reactive power support, although no NEM-connected assets have been modified to be used as synchronous condensers. The technology's fuel efficiency and rapid response capabilities address critical grid stability requirements, including fast start times, effective turndown ratios, responsive operation during network variability events, and different operational modes (high and low load operations). While extended low-load operation can influence component wear and maintenance requirements, operational mode is not expected to materially affect overall retirement cost assumptions.

Contemporary market trends indicate a shift toward incorporating low emissions solutions in new reciprocating engine developments. This transition primarily involves fuel blending strategies and hydrogen firing capabilities, with new installations designed to accommodate hydrogen concentrations ranging from 10% to 100%[19]. Reciprocating engines can operate on various fuels, including natural gas, biogas, and hydrogen blends, providing operational flexibility for transitioning energy systems. However, the potential for hydrogen or other fuel blends is not expected to materially impact retirement estimates for existing assets within the scope of this review. Of note is CCS is not generally considered for reciprocating engines given the main function of the engines is for peaking operation.

3.3.3 Retirement scenario

Table 21 outlines the configuration for a typical NEM-connected reciprocating engine. This scenario has been selected based on a plausible project for installation in the NEM in 2025 given the above discussion on typical options and current trends.

Table 21 Retirement scenario configuration – reciprocating engine

Item	Unit	Value	Comment
Configuration			
Technology / OEM		Wartsila	MAN Diesel and Rolls Royce Bergen (RRB) also offer comparable engine options.
Make model		18V50DF	Including Selective Catalytic Reduction (SCR) for NOx emission control. Dual fuel (gas and liquid fuel (e.g. diesel) operation, with hydrogen readiness (25% blend with natural gas) based on current capability. OEM to be consulted on hydrogen blend operation in this configuration. Natural gas operation with pilot diesel supply is normally used for dual fuel units.
Unit size (nominal)	MW	17.6	ISO / nameplate rating at generator terminals.
Number of units		12	
Total plant size (Gross)	MW	211.2	25°C, 110 metres, 60%RH

[19] **Wärtsilä succeeds in world's first hydrogen blend test - Wärtsilä Energy**

O&M estimates

The following table provides fixed and variable O&M cost estimate for the defined reciprocating engine scenario.

Table 22 O&M estimates – Reciprocating engine

Item	Unit	Value	Comment
Fixed O&M Cost	$ / MW (Net)	36,000	Based on preparation of a high-level bottom-up estimate.
Variable O&M Cost	$ / MWh (Net)	9	Based on preparation of a high-level bottom-up estimate.

3.3.4 Cost estimates

Retirement key assumptions

The following assumptions have been made for dual fuel reciprocating engine power station technology for the case of a 210MW power plant as describe above.

- The cost basis is expected to be to a AACE Class 5 level.
- Removal to underside of hardstand areas/slabs, significant solid structures (e.g. stack footings) that extend beyond underside will also remain in-situ.
- Significant solid structures that remain in-situ are to be made flush with the surface.
- Large cooling water pipes (steel or concrete) are removed or filled where relevant.
- Other than treatment of sub-surface or at surface features noted above foundations removed to 1.5 metres below ground level (mbgl).
- Backfill voids with crushed concrete (secured at site) (<100 millimetres (mm) diameter) to ground level.
- Owners' costs are not included.
- Cap and contain strategy (e.g. no material off-site).
- All capping material, clay and topsoil won on-site.
- End land use will be brownfield for industrial use.
- No CCS is assumed.

Retirement process overview

The retirement of reciprocating engine power technology will (at a high level) include:

- Remove site asbestos waste based on site asbestos register with disposal to on-site asbestos cell (if asbestos is found on site).
- Removal of remaining polychlorinated biphenyl (PCB) rectifier transformers, assuming PCB containing equipment is removed from site prior to closure.
- Discharge water from cooling tower units to ground level and remove concrete foundations.
- Remove pumps, piping, and concrete foundations from cooling water pump pits.
- Dismantle and remove reciprocating engine gensets for disposal and sale and remove concrete foundations.
- Demolish engine hall to slab level and remove foundations.
- Remove and dispose high voltage (HV) transformers, demolish bunded area and remove foundations.
- Dismantle and remove all water and fuel storage tanks and prepare for steel salvage.
- Fell charge administration building to slab and remove foundations.
- Remove parking lot and access road slabs.
- Dismantle all supply and return water pipes for the ash delivery system.
- Demolish remaining buildings to slab and remove foundations.

Retirement estimates

Retirement estimates for the reciprocating engine scenario reflective of NEM-connected dual fuel reciprocating engine generation plants are outlined in Table 23.

Table 23 Retirement estimate – reciprocating engine

	Reciprocating Engine Gensets
Decommissioning, Demolition & Rehabilitation Costs ($/MW)	$64,500
Disposal Costs ($/MW)	$22,000
Recycling Costs ($/MW)	($28,500)
Retirement Costs ($/MW)	**$58,000**

Duration of retirement

Table 24 below provides an estimate for the relevant durations, pertaining to the process for retirement for typical reciprocating engine technologies (size 210MW nominal).

Table 24 Duration periods – reciprocating engine

Activity	Duration (weeks / years)
Decommissioning	30 / 0.6
Demolition & Dismantling	52 / 1
Rehabilitation	156 / 3

4. Emerging energy generation technologies

The scope of Section 4 pertains to for emerging energy generation technologies connected, or expected to be connected in future, to the NEM and their associated retirement cost estimates. The technologies included in this section are at varying stages of maturity and commercial-scale implementation, where some technologies are yet to come online but are anticipated to enter the market in coming years when commercially viable (i.e. electrolysers and solar thermal). This means there are limited examples of these assets being retired, and as such, few real data points for retirement costs. OPEX costs are not provided for the technologies presented in this Section.

4.1 Biomass

Power generation from biomass can take many forms and cover a variety of technologies, where "biomass" includes any organic matter or biological material that can be considered available on a renewable basis, including materials from animals and/or plants as well as wastes from various sources.

For a power generation facility utilising a solid biomass such as woodchips as feedstock, the following elements are included[20,21]:

- Feedstock receival and storage.
- Feedstock preparation to reduce moisture and/or produce a particle size distribution range, if required.
- Thermal conversion unit and boiler to generate steam. Typically, an absorbent such as limestone is added with the biomass feedstock to absorb gaseous contaminants such as sulphur as part of the process.
- Steam turbine for power generation.
- Condenser to condense the steam into water, which can then be treated to boiler feed water quality and recycled to the process.
- Exhaust gas treatment, such as scrubbers or filters for particular, SO_x and NO_x removal.
- Ash handling system, where biomass ash and any added absorbents are cooled and removed to an ash silo.

4.1.1 Technology overview

Power can be generated from biomass via any of the following:

- Combustion or incineration, where a solid biomass is combusted in a steam generation boiler, typically a grate or circulating fluidised bed (CFB) type combustor. The generated steam is utilised in a traditional steam turbine to generate power. Solid biomass considered for these processes include wood chips, agricultural residues such as straws or bagasse and other waste streams such as municipal solid waste.
- Gasification of biomass, followed by combustion of the produced gas in a reciprocating engine or gas turbine to produce electricity. Gasification is a thermochemical process that transforms carbon-based biomass into a combustible gas consisting of a mixture of steam, hydrogen, carbon monoxide, methane, carbon dioxide and various minor species and contaminants. Nitrogen could also be present in reasonable quantities if the gasification process is air-blown. The produced combustible gas is firstly purified of entrained solids and gaseous impurities and then combusted in an engine or gas turbine.
- Pyrolysis of biomass can also be considered, followed by combustion of the produced gas and oil phases in a gas engine and/or oil boiler. Pyrolysis is a thermochemical process that transforms carbon-based biomass into a combustible gas, oil and aqueous phase in an oxygen-free atmosphere.
- Anaerobic digestion of biomass to produce biogas and combustion of biogas in a gas engine or combined heat and power system. Biomass is broken down to biogas and digestate through the use of microorganisms over a period of time. The biogas typically consists of 50-60 vol % methane, 30-45 vol% CO2, and contaminants such as H2S, nitrogen compounds, entrained particulate matter, water and trace compounds such as ethylbenzene and halogenated compounds. The gas is treated to some degree, typically to remove at least condensed water, H2S and ammonia and then combusted for power generation.

[20] Bolhar-Nordenkampf, M. et. Al. (May 2006). Operating experience from two new biomass-fired FBC Plants. 10.13140/2.1.3985.8248.
[21] Kaltschmitt, M. (January 2012). Biomass as renewable source of energy, possible conversion routes. 10.1007/978-1-4419-0851-3_244.

4.1.2 Recent trends

Biomass power generation contributes a small but stable share of Australia's renewable energy mix, accounting for approximately 1.4% of total generation capacity in 2023[22]. In Queensland, approximately 1.1 GWh of electricity was generated from biomass sources in 2023, compared with 797 MWh in New South Wales[23].

Representative facilities include the Rocky Point Biomass Power Station in Queensland[24] (30 MW, commissioned in 2001, fuelled by bagasse) and Wilmar Sugar's network of eight sugar mills, which collectively provide 202 MW of cogeneration capacity and export around 311 GWh annually[25]. In New South Wales, the Broadwater and Condong bioenergy plants contribute 38 MW and 30 MW respectively from bagasse[26], while Sydney Water operates nine sites with a combined 31.4 MW of capacity from landfill gas and sewage-derived biogas.

While biomass is not expected to match the scale of wind or solar generation, project activity continues. As of 2022, two biomass projects with a combined capacity of 61 MW were under development[27]. Globally, the sector is growing at a compound annual rate of 5.3%, with installed capacity projected to increase from 83.8 GW in early 2024 to 96.8 GW by 2033[28]. Growth is driven by renewable energy targets and the utilisation of domestic waste materials, particularly woody biomass, which comprised 48.3% of global biomass power generation in 2024. Solid biomass fuels (e.g. pellets, wood chips, agricultural residues) collectively represented 69.4% of the market, with combustion technologies accounting for 56.3% of installed capacity[29].

Recent developments in circulating fluidised bed (CFB) boiler technology have enabled scaling of biomass-fired power. The largest biomass-exclusive CFB facility, located in Teesside (UK), is a 299 MW combined heat and power (CHP) plant commissioned in 2022. While operational status is uncertain due to financial restructuring[30], the plant has a nominal output of 2.4 TWh per year, utilising 2.4 Mt of wood-based fuel and displacing an estimated 1.2 Mt CO_2 per annum.

Key constraints for biomass generation include feedstock availability, typically within a 50–100 km radius, due to high transport costs and low energy density. Biomass also competes with other sectors for feedstock, particularly biofuels and biogas production.

From a retirement perspective, economies of scale may reduce cost per installed MW as plant size increases. However, based on comparative data for coal-fired stations (Section 3.1.5), retirement cost variation by size is limited. For example, the retirement cost of a large facility was estimated at 98% that of a small facility on a $/MW basis, indicating marginal cost differences at scale.

4.1.3 Retirement scenario

Drawing on existing biomass facilities and current trends in the market a typical hypothetical project has been identified as comprising sub-critical boilers utilising biomass (wood chips, pellets or prepared biomass feed) for the purposes of preparing retirement costs. Other technology options presented in Section 4.1.1 have not been considered as part of this Report. Circulating fluidised bed units (CFBs) have been selected as part of the biomass power generation flow scheme as these units offer several advantages such as high combustion efficiency and low nitrogen oxide emissions. The hypothetical projects are presented in two cases at a capacity of 30 MW and 150 MW, at half the capacity of the world's largest CFB units. While larger-scale units tend to have lower associated cost per installed MW, biomass-fired power stations are limited by biomass availability. Therefore, the facility capacity is capped at 150 MW.

The following equipment is included at site:

– CFB boiler, steam turbine, generator, air-cooled condensers, exhaust gas treatment, CFB exhaust stack.
– Fuel storage area (shed) and ash silos.

[22] Clean Energy Council. (2024). Clean Energy Australia.
[23] Australia: biomass energy electricity generation by state 2023| Statista. Website accessed 01/05/2025.
[24] Power plant profile: Rocky Point Biomass Power Plant, Australia. Website accessed 02/05/2025.
[25] Power to the grid - Wilmar Sugar. Website accessed 02/05/2025.
[26] Bioenergy | NSW Climate and Energy Action. Website accessed 01/05/2025.
[27] Clean Energy Council. (2024). Clean Energy Australia.
[28] Publications - Biomass to Power 2024/2025. Website accessed 29/04/2025.
[29] Biomass Power Generation Market Research Report. (February 2025). Market.US.
[30] Tees Renewable Energy Plant, Teesside - Power Technology. Web site accessed 29/04/2025.

– Ancillary plant and equipment.
– Buildings including administration offices, workshops and stores.

Table 25 Retirement scenario configuration – biomass

Item	Unit	Value	Comment
Technology	-	Sub-critical boiler	With mechanical draft cooling tower.
Fuel source	-	Woodchips	-
Make model	-	Western OEM	-
Unit size (nominal)	MW	30	-
Number of units	-	1	-
Steam Pressures (Main / Process)	MPa	7 / 0.6	-
Steam Temperatures (Main / Process)	°C	470 / 162	-
Process steam mass flow rate	kg/s	16.0	Approximately 37% of main steam to turbine
Condenser pressure	kPa abs	7.5	-

4.1.4 Cost estimates

The supplied retirement cost estimates are based on those for coal-fired power stations utilising similar equipment, which are well known, including retirement costs. Therefore the cost basis is expected to be to AACE Class 5 level. There are elements that will be different for a biomass-fired power station; however, these are generally expected to have smaller contributions to the retirement cost.

Retirement key assumptions

The following assumptions have been considered in reviewing the Retirement, Disposal and Recycling costs:

– Concrete will be removed to 1.0m below finished ground level, with residual concrete left in place.
– Copper cabling is at a maximum depth of more than 1.0m and the majority of copper present on site is recoverable for scrap value.
– Existing site roads and laydown areas etc are suitable for decommissioning works, and remediation of these will be limited to deep ripping the surface and contouring.
– Copper and steel scrap values will be considered to be at the midpoint of a range published in the public domain at the time of preparing this Report[31].
– Items such as offices and office equipment, warehousing, workshops, ablutions blocks and similar are pre-existing on site at commencement of retirement.
– Assets will be retired at end of technical life, and therefore not be suitable for re-purposing on another site.
– Waste oil is expected to be recycled for free.
– The volume of ash generated from biomass does not require an ash dam and is stored onsite in silos for periodic removal from site.
– Wood chip ash can be used beneficially as fertiliser, soil enhancer or compost additive, among other uses.
– Concrete and ash associated with the silo (upon shutdown) is included in the disposal cost.

[31] Latest scrap metal prices | What is your scrap metal worth?. Website accessed 02/05/2025.

Retirement process overview

The following outlines the general process for retirement of a biomass-fired power station. This process is very similar to that outlined for small coal-fired power stations outlined in Section 0:

- Dismantle biomass receival bins and remove.
- Dismantle biomass storage sheds and remove concrete foundations.
- Dismantle and remove feed preparation equipment including milling and sieving equipment, and dryers, and remove concrete foundations.
- Dismantle and remove covered conveyors and infrastructure from storage to feed preparation and/or CFB equipment and remove footings.
- Dismantle and remove CFB system, including feed bins, CFB, ash removal systems and all associated piping for boiler feed water and steam systems. Remove structural steel and/or CFB housing and concrete foundations.
- Discharge water from cooling tower units to ground level and remove concrete foundations. Also remove pumps, piping and concrete foundations from cooling water pits.
- Dismantle and remove steam turbine and concrete foundations.
- Remove condensers and supporting equipment and structural steel and concrete foundations.
- Remove ash from ash silos and demolish ash silos and foundations.
- Remove and dispose high voltage (HV) transformers, demolish bunded area and remove foundations.
- Dismantle clarification plant including removal of pumps, tanks, piping, etc and demolish, remove water from holding tanks and demolish.
- Dismantle and remove all water and fuel storage tanks and prepare for steel salvage.
- Fell charge administration building to slab and remove foundations.
- Remove parking lot and access road slabs.
- Dismantle all supply and return water pipes for the ash delivery system.
- Demolish remaining buildings to slab and remove foundations.

Retirement estimates

While biomass-fired CFB power stations differ in fuel type from coal-fired plants, the core plant configuration and equipment are broadly similar. As such, retirement cost estimates are considered comparable, excluding ash dam rehabilitation, which is typically not required for biomass facilities due to lower ash volumes and beneficial reuse.

Demolition of feedstock handling infrastructure is included in cost assumptions but represents a minor component due to smaller scale and simpler construction.

Based on industry benchmarks, coal plant retirement costs are estimated at $180,000/MW[32], inclusive of ash dam remediation[33]. Adjusted for biomass, costs are assumed in the range of $125,000–$150,000/MW.

The biomass-fired case aligns most closely with the brown coal, sub-critical scenario (Section 3.1.5), with cost reductions due to smaller capacity (150 MW) and simplified plant design. Indicative decommissioning and demolition costs are $168,000/MW, with an assumed salvage benefit of $18,500/MW—approximately half that of the coal case—reflecting lower equipment density and reduced material volumes.

Material recovery estimates are based on data from the 320 MW Tallawarra Power Station[34], with biomass units expected to yield 50–60% of the recovered steel and concrete volumes for a 150 MW scenario.

Table 26 Retirement estimate – biomass

	Biomass
Decommissioning, Demolition and Rehabilitation Costs ($/MW)	$150,000
Disposal Costs ($/MW)	$2,000
Recycling Costs ($/MW)	($18,500)
Retirement Costs ($/MW)	**$133,500**

Duration of retirement

Retirement duration is estimated to be similar in time for a 30 and 150 MW facility, with potentially a little shorter time span for demolition for the smaller facility. These durations are assumed to be similar to those for a small coal-fired power station as stated in Section 0.

Table 27 Duration periods – biomass

Activity	Duration (weeks) Small Power Stations – ~30MW	Duration (weeks) Small Power Stations – ~150MW
Decommissioning	16	26
Demolition	60	72
Rehabilitation	20	26

[32] Early Phase-out of Coal Plants: Methodology Concept | Gold Standard | GS. Website accessed 30/04/2025.
[33] GHD internal reference data
[34] Demolition. Website accessed 02/05/2025.

4.2 Large-scale solar photovoltaic

Utility scale Solar PV generation is well established as a significant renewable energy technology in Australia and is currently the cheapest form of electricity generation. Utility scale PV has been deployed in Australia since 2012 and there is expectation that by 2045 approximately 35 GW of PV modules will require retirement which could provide an estimated economic value of $167 billion[35].

In utility-scale solar PV systems, tens to hundreds of thousands of solar PV modules (mounted on concreted-in single-axis trackers) are connected in strings to inverters, which convert the DC electricity from the modules to AC. For stand-alone solar farms the AC outputs from each of the inverters in the solar farm are aggregated and exported to the network through transformers and switchyards.

4.2.1 Technology options

To date, utility-scale PV plants have typically been installed in either fixed-tilt or single-axis tracking configurations. In fixed-tilt systems, modules are mounted on a static frame oriented to achieve the required generation profile. In Australia fixed tilt systems have traditionally been oriented to the north to maximise annual generation, however, some fixed-tilt systems are arranged with panel orientations split between east and west facing to maximise installed capacity on a site and to provide generation that aligns better with morning and evening peaks in demand.

The majority of recently constructed utility-scale solar farms in Australia utilise single-axis tracking systems, where modules are mounted on a torque tube structure which rotates on a north-south axis, allowing the modules to track the sun's movement from east to west. This single axis tracking configuration generally provides a lower Levelised Cost of Energy than the fixed tilt systems.

Dual axis tracking systems where structures allow module orientation to move both east-west on a daily basis and north-south on a seasonal basis, come at additional capital expense and have not yet been deployed in the utility scale market in Australia.

Module selection is also a key criteria in solar farm design. Over time modules have evolved to improve efficiency and lower cost. Historically, mono-facial modules (which generate from light capture on one side of the module) have been common however, bi-facial panels, which have the ability to capture indirect light on the rear of the panel, have now become more cost efficient and prevalent.

4.2.2 Recent trends

As of September 2024 there was over 37GW of installed PV generation across Australia.[36] In 2024, committed utility-scale solar farms averaged 150MW capacity and ranged in size from single-digit to 450MW.[37]

PV module efficiency continues to improve over time and some manufacturers are also increasing module size such that modules exceeding 700 W are now on offer. However, limitations are expected with respect to panel size due to manual handling limitations (size and weight). Increases in module efficiency and size allows for a reduction in overall plant footprint, including reduction in cabling and structures for given installed capacity. This can improve retirement costs by reducing the costs associated with Balance of Plant systems. Given the continuing cost reduction in PV module price, some developers have been increasing the DC:AC ratio of the solar farm in an attempt to improve the generation profile in the shoulder periods. This results in installation of more DC equipment for a given capacity of network connection which can offset benefits achieved by increasing module efficiency. A smaller number of larger capacity panels should translate to reduced retirement costs, due to the reduced number of panels requiring removal, albeit this is partially offset by the larger size per panel.

The move to bifacial modules, particularly dual glass modules, is expected to lead to lower degradation rates and increase the expected lifespan of modules to 30 years[38] or more. This is expected to be an improvement on previous module technology and is likely to delay but not reduce retirement costs.

[35] **Recycling and decommissioning of renewable energy tech**
[36] https://pv-map.apvi.org.au/analyses#:~:text=As%20of%2030%20September%202024,capacity%20of%20over%2037.8%20gigawatts.
[37] https://cer.gov.au/markets/reports-and-data/large-scale-renewable-energy-data
[38] **End-of-Life Management for Solar Photovoltaics | Department of Energy**

Whilst traditionally solar PV facilities were standalone generators, given the value obtained from the generation profile of solar PV there is increasing interest for PV facilities to be combined with Battery Energy Storage Systems (BESS) or at least have capacity for addition of BESS in the future. In particular the potential for DC-coupling (where batteries can connect directly to the DC busbar of the inverter alongside the solar PV connections) offers potential to utilise common MV equipment, which would reduce equipment requirements and hence retirement costs related to a combined facility.

Single-axis tracking systems that mount one module in a portrait configuration ('1P trackers') are by far the most common configuration and therefore form the basis for the 'Selected hypothetical project'. It should be noted that other configurations are possible for single axis tracking that can reduce equipment requirements, and potentially lower retirement costs, however these are less common due to higher wind loading and increased spacing requirements.

In terms of PV module recycling progress is being made in Australia, both in terms of legislating the need, as well as developing technologies to do so. Victoria, South Australia, Queensland and the ACT have already banned the disposal of solar modules to landfill and NSW now treats solar modules as e-waste[39].

However the cost of recycling is material. The most common process in Australia is for panels to be physically shredded and then used as some form of aggregate, whereas other processes seeking to extract elements for re-use are more technically complex and therefore cost more. Current recycling cost is reported in one source as $10-20 per panel[40], and in another as $28, though the latter is believed to be reflective of an approach seeking to recover more value[41]. There have been reports of some energy companies stockpiling panels to defer the cost of recycling panels, potentially also benefitting from expected reductions in cost over time.

Only 17% of panels components are presently recycled in Australia, being mostly aluminium frames and junction boxes, even though 85% of a module is made up of recyclable materials – because it is difficult to separate the materials from one another[42].

However in the EU, regulations require 85% of panel materials to be collected and 80% to be recycled[43] - this has no doubt driven innovation in the sector as well as providing critical mass for industries to develop. It is possible that a similar trend will be seen in Australia over time and it is certainly expected that as the recycling industry matures and scales that module recycling costs will reduce.

4.2.3 Retirement scenario

The selected retirement scenario is a stand-alone single axis tracking solar farm with capacity of 200 MW AC.

Table 28 Retirement scenario configuration – solar PV

Item	Unit	Value	Comment
Technology		Single Axis Tracking (SAT)	Based on recent trends.
Plant DC Capacity	MW_p	240	
Plant AC Inverter Capacity	MVA	240	Additional reactive power allowance for NER compliance – typical 1.2 oversizing
Plant AC Grid connection	MW	200	Active power at point of connection
DC:AC Ratio (solar PV to grid)		1.2	Typical range from 1.1 to 1.3
Economic Life (Design Life)	Years	30	Consideration given to warranties, rate of module degradation and incremental improvements over time in panel efficiency
Technical Life (Operational Life)	Years	30	40 if piles don't corrode and the spare parts remain available.

[39] Decommissioning by design: reusing and recycling wind farm infrastructure - Energy Magazine
[40] **Repair, reuse and recycle: dealing with solar panels at the end of their useful life**
[41] **Australia faces solar waste crisis - The University of Sydney**
[42] **Technological advancement in the recycling of wind, solar and battery assets - Hamilton Locke**
[43] **Decommissioning by design: reusing and recycling wind farm infrastructure - Energy Magazine**

4.2.4 Cost estimates

Cost estimates for large scale PV retirement are to AACE Class 5 level and were based on internal reference estimates for retirement of MW-scale PV arrays, and costs for panel recycling in the public domain. The cost estimate was scaled according to the dependencies for various elements. For example, panel removal labour is linked to the number of panels, and equipment mobilisation and demobilisation costs are linked to the number of concurrent work crews removing panels. No discrete contingency has been allowed, however could be considered prudent given the level of accuracy of the contained estimates.

Retirement key assumptions

The following Assumptions have been considered in reviewing the above Retirement and Recycling costs:

- Concrete will be removed to 1.0m below finished ground level, with residual concrete left on place.
- Panels are all mounted on driven piles with no allowance for concrete removal included.
- Copper cabling is at a maximum depth of more than 1.0m and the majority of copper present on site is recoverable for scrap value.
- Existing site roads and laydown areas etc are suitable for decommissioning works, and remediation of these will be limited to deep ripping the surface and contouring.
- PV panels will be disposed of at a cost of $15/panel[44], the midpoint of the range quoted by UNSW. While landfill disposal is cheaper, increasing landfill bans necessitate allowances for panel recycling. Recycling costs are expected to decline over time with scale and learning effects.
- Copper and steel scrap values will be considered to be at the midpoint of a range published in the public domain at the time of preparing this Report[45].
- Items such as offices and office equipment, warehousing, workshops, ablutions blocks and the like are pre-existing on site at commencement of retirement.
- 100 PV panels can be removed per day by a 2-person crew. The number of crews has been estimated on the basis of all panels being removed in a 16-week window.
- Assets will be retired at end of technical life, and therefore not be suitable for re-purposing on another site.
- Waste oil is expected to be recycled for free.
- Items will be transported 300km for recycling or disposal, which is an assumption which is considered reasonable given the remote nature of many utility scale PV installations.
- Three elements have been considered in terms of recycling with respect to utility scale PV:
  - Steel support structures for the PV panels and trackers can be considered to be of value as scrap steel.
  - Copper cabling (both AC and DC) can also be considered to have some scrap value.
  - Conversely, PV panel recycling needs to be allowed for, and comes at a cost which more than offsets the revenues associated with the above 2 items.
- Scrap values have been used as per the midpoint of ranges published in the public domain.[46]

[44] **Repair, reuse and recycle: dealing with solar panels at the end of their useful life**
[45] **Latest scrap metal prices | What is your scrap metal worth?**
[46] **Latest scrap metal prices | What is your scrap metal worth?**

Retirement process overview

The retirement of large-scale PV will (at a high level) include:

– Site establishment including site management team and vehicles.
– Electrical disconnection from the grid.
– Progressive removal of panels from tracking mechanisms and stacking into shipping containers for removal off site by truck and transport to a recycling facility.
– Progressive removal of tracking mechanisms and support structures for recycling.
– Removal of civils structures for disposal to landfill.
– Site demobilisation.

Retirement estimates

Retirement cost for the 200MW PV installation as contemplated in the hypothetical project, is estimated at $110,000 per MW, and includes an allowance for net recycling cost per below and incorporates any disposal costs.

The (positive) recycling cost for the panels themselves outweighs the credit from recycling copper cable and steel support structures, resulting in a net positive recycling cost overall.

About 20% of the estimated cost is allocated to panel recycling, and so there would be a notable flow through effect to retirement costs, should panel recycling cost decrease over time. It has been assumed that panels would not be redeployed on another site, but should such an arrangement be made, this would also have a material flow through to retirement cost.

Table 29 Retirement estimate – solar PV

	Large scale solar PV
Decommissioning, Demolition & Rehabilitation ($/MW)	$104,000
Disposal Costs ($/MW)	$1,000
Recycling Costs ($/MW)	$5,000
Retirement Costs ($/MW)	**$110,000**

Duration of retirement

Panel removal is expected to often be critical path in terms of the timeframe for PV array retirement. This means there is some ability to compress the overall timeline through addition of extra panel removal work crews operating in parallel., For the purpose of this Report, it has been assumed that panel removal can be completed in 16 weeks, with additional time allowed for mobilisation / demobilisation of the retirement team and trailing workflows around panel removal (removal of support structures, civils and cables). In all, a total of 22 weeks is estimated for retirement. There is some overlap between phases from a schedule perspective due to the scale of the installation and geographically spread locations of work fronts.

Table 30 Duration periods – solar PV

Activity	Duration (weeks)
Decommissioning	2
Demolition & Dismantling	18
Rehabilitation	2

4.3 Distribution connected solar photovoltaic

Solar PV generation connected to the electrical distribution network (as opposed to connection to the transmission network) is commonly encountered in the Australian context. For the purposes of this Report, the size of solar PV farms suitable for connection to the distribution network are assumed to be of a scale up to 40 MW, as advised by AEMO, however the assumed facility for this particular study is 5 MW scale.

As with utility-scale solar PV systems, albeit at a smaller scale, PV modules (typically on single-axis trackers for large distribution connected facilities) are connected in strings to inverters, which convert the DC electricity from the modules to AC. For stand-alone solar farms the AC outputs from each of the inverters in the solar farm are aggregated and exported to the network – noting the voltage and the pathway for the distribution connected systems may be different than for utility-scale systems.

4.3.1 Technology overview

In fixed-tilt systems, modules are mounted on a static frame oriented to achieve the required generation profile. In Australia fixed-tilt systems have traditionally been oriented to the north to maximise annual generation, however, some fixed-tilt systems are arranged with panel orientations split between east and west facing to maximise installed capacity on a site and to provide generation that aligns better with morning and evening peaks in demand. For the distribution connected systems some may also be oriented based on rooftop layout.

As with utility-scale, distribution-connected solar PV could employ single-axis tracking, though due to the smaller scale, there will be increased propensity for fixed systems. On a case-by-case basis fixed systems may be preferred for the following reasons:

- Single-axis tracking takes up more land due to the need to avoid shadowing of panels, and land may be more constrained for distribution connected solar PV installations.
- The smaller scale may come with assumed unmanned operation, which is less compatible with single axis tracking which requires increased levels of maintenance.
- Single axis tracking comes at higher cost which could be a factor if projects are capital constrained.
- Any roof top systems are likely to be fixed.

Module selection is also a key criterion in solar farm design. Over time modules have evolved to improve efficiency and lower cost, leading to development of bi-facial panels, which have the ability to capture indirect light on the rear of the panel, as opposed to mono-facial modules (which generate from light capture on one side of the module) which have historically been more common. Bifacial panels are expected to penetrate into the larger scale of distribution connected PV whilst there may be more tendency for mono-facial panels for smaller or roof mounted systems.

4.3.2 Recent trends

Trends are largely the same as observed for utility-scale solar PV generation and described earlier in Section 4.2. There is a move towards larger individual panels due to lower overall installed cost, and for distribution connected scale this is also expected to be a driver, and trump manual handling complications that come with this.

As with utility-scale facilities, there is an expectation that, distribution scale batteries will increasingly be co-located with PV (or designed to future-proof to this effect). As the cost of lithium batteries continues to fall and the time value of solar generation falls, it becomes increasingly beneficial to couple BESS with PV from an economic perspective. Similarly to utility-scale, there is expected to be increased exploration of DC coupling (where batteries can connect directly to the DC busbar of the inverter alongside the solar PV connections).

Single axis tracking systems remain sufficiently common at this scale to form the basis of the 'retirement scenario', though at smaller scale fixed panels may be considered purely due to capital cost and maintenance.

As discussed in Section 4.2.2, there is progress in PV recycling in Australia both in terms of legislation and enabling technologies, with Victoria, South Australia, Queensland and the ACT already banning the disposal of solar modules to landfill and NSW treating solar modules as e-waste[47]. Further, similar trends are observed for recycling of distribution connected as utility-scale systems.

4.3.3 Retirement scenario

The selected retirement scenario is a stand-alone single axis tracking solar farm with capacity of 5 MW AC.

Table 31 Retirement scenario configuration – solar PV

Item	Unit	Value	Comment
Technology		Single Axis Tracking (SAT)	Based on recent trends particularly for larger scale systems
Plant DC Capacity	MW_p	7.5	
Plant AC Inverter Capacity	MVA	6	Additional reactive power allowance for NER compliance – typical 1.2 oversizing
Plant AC Grid connection	MW	5	Active power at point of connection
DC:AC Ratio (solar PV to grid)		1.5	Aligned for consistency with Aurecon Report. Typical range for a utility scale system as seen in industry is 1.1 to 1.3, however a ratio of 1.5 is considered acceptable
Economic Life (Design Life)	Years	30	Consideration given to warranties, rate of module degradation and incremental improvements over time in panel efficiency
Technical Life (Operational Life)	Years	30	40 if piles don't corrode and spare parts remain available

4.3.4 Cost estimates

Cost estimates for distribution connected solar PV retirement are to AACE Class 5 level and based on internal reference estimates for retirement of MW-scale PV arrays, and costs for panel recycling in the public domain. The cost estimates are scaled according to the dependencies for various elements. For example, panel removal labour is linked to the number of panels, where equipment mobilisation and demobilisation costs are linked to the number of concurrent work crews removing panels. No discrete contingency has been allowed, however, could be considered prudent given the level of accuracy of the contained estimates.

Retirement key assumptions

The following assumptions have been considered in the retirement and recycling costs and are largely unchanged from the utility-scale system shown in the Section 4.2.4:

– Concrete will be removed to 1.0m below finished ground level, with residual concrete left in place.
– Panels are all mounted on driven piles with no allowance for concrete removal included.
– Copper cabling is at a maximum depth of more than 1.0m and the majority of copper present on site is recoverable for scrap value.
– Existing site roads and laydown areas are suitable for decommissioning works, and remediation of these will be limited to deep ripping the surface and contouring.
– PV panels will be disposed of at a cost of $15/panel[48], the midpoint of the range quoted by UNSW. While landfill disposal is cheaper, increasing landfill bans necessitate allowances for panel recycling. Recycling costs are expected to decline over time with scale and learning effects.
– Copper and steel scrap values will be considered at the midpoint of a range published in the public domain at the time of preparing this Report[49].

[47] **Decommissioning by design: reusing and recycling wind farm infrastructure - Energy Magazine**
[48] **Repair, reuse and recycle: dealing with solar panels at the end of their useful life**
[49] **Latest scrap metal prices | What is your scrap metal worth?**

– Items such as offices and office equipment, warehousing, workshops, ablutions blocks and the like are pre-existing on site at commencement of retirement.
– 100 PV panels can be removed per day by a 2-person crew. The number of crews has been estimated on the basis of all panels being removed in a 2-week window.
– Assets will be retired at end of technical life, and therefore not suitable for re-purposing on another site.
– Waste oil is expected to be recycled for free.
– Items will be transported 100km for recycling or disposal (< 300km assumption used for utility-scale, at distribution scale might typically be located closer to load and therefore likely closer to suitable recycling or disposal sites).
– Three elements have been considered in terms of recycling with respect to distribution connected PV:
  - Steel support structures for the PV panels and trackers can be considered of value as scrap steel.
  - Copper cabling (both AC and DC) can also be considered to have some scrap value.
  - Conversely, PV panel recycling needs to be allowed for, and comes at a cost which more than offsets the revenues associated with the above two items.
– Scrap values have been used as per the midpoint of ranges published in the public domain.[50]

Retirement process overview

The retirement of distribution connected PV will (at a high level) include:

– Site establishment including site management team and vehicles.
– Electrical disconnection from the distribution network grid.
– Progressive removal of panels from tracking mechanisms and stacking into shipping containers for removal off site by truck and transport to a recycling facility.
– Progressive removal of tracking mechanisms and support structures for recycling.
– Removal of civil structures for disposal to landfill.
– Site demobilisation.

Retirement estimates

Retirement cost for the 5MW solar PV installation as contemplated in the retirement scenario, is estimated at $208,000 per MW, and includes an allowance for net recycling cost per below and incorporates any disposal costs. This is higher per MW than the utility scale estimation due to the fact that not all costs can scale linearly with capacity.

The net positive recycling cost for the panels themselves outweighs the credit from recycling copper cable and steel support structures, resulting in a net positive recycling cost overall.

About 15% of the estimated cost is allocated to panel recycling, and so there would be a notable flow through effect to retirement costs should panel recycling cost decrease over time. It has been assumed that panels would not be redeployed on another site, but should such an arrangement be made, this would also have a material flow through to retirement cost.

Table 32 Retirement estimate – distributed network solar PV

	Distributed network solar PV
Decommissioning, Demolition & Rehabilitation ($/MW)	$200,000
Disposal Costs ($/MW)	$1,000
Recycling Costs ($/MW)	$7,000
Retirement Costs ($/MW)	**$208,000**

[50] **Latest scrap metal prices | What is your scrap metal worth?**

Duration of retirement

Panel removal is expected to drive the critical path for PV array retirement, though timelines can be shortened by deploying multiple work crews in parallel. For this report, a 5-week retirement duration is assumed with 2 weeks for panel removal and 3 weeks for mobilisation, demobilisation, and follow-on activities. Overlapping work fronts may enable further schedule compression and cost savings.

Table 33 Duration periods – solar PV

Activity	Duration (weeks)
Decommissioning	1
Demolition & Dismantling	3
Rehabilitation	1

4.4 Concentrated solar thermal

Technologies known as Concentrated Solar Thermal (CST), also known as Concentrated Solar Power (CSP) generally have some elements in common:

– Mirrors/collectors deployed over a large area to collect solar energy.
– solar energy redirected onto a comparatively small solar receiver.
– transfer of the energy to a thermal fluid which absorbs the energy.
– and either uses the energy immediately for power generation or store the energy for a period of time, providing time-shifting of the power generation.
– Either way this often requires a series of heat exchangers to transfer the energy from the fluid to steam, and then the steam system including demineralised water plant, deaerator, steam turbine and cooling infrastructure. In the case of molten salt systems the thermal fluid also requires 'hot' and 'cold' tanks, in between which the fluid passes as it either picks up energy or discharges it.

CST technology is generally classified as either "line focused", where the energy is focused on a linear structure and single-axis trackers are used or "point focused" where energy is directed to a single focal point like a receiver tower.

4.4.1 Technology overview

Line focused systems use single-axis trackers to improve energy absorption across the day, increasing the yield by modulating position depending on the angle of incoming solar radiation and allowing this to be redirected onto a collector.

Currently most line focused concentrating systems are Parabolic Trough Collectors (PTCs) – with a line of curved mirrors focusing solar radiation on a heat receiver tube, together with an associated support structure and foundations. Often PTCs are connected together into a chain which the heat transfer fluid flows through, so achieving better economies of scale. The heat transfer fluid exchanges heat to produce superheated steam which typically passes through a steam turbine to generate power. An alternative, but less common, linear system uses a device called Fresnel collectors. These employ an array of relatively flat mirrors and redirect the sun's rays onto a linear receiver located some metres above the mirrors, though (unlike PTCs) not physically connected to them.

Point focused solutions are dominated by Solar Towers, also known as Power Towers. A large number (thousands) of heliostats (mirrors) are located in a circular or semi-circular arrangement around a tall central tower which has a receiver. The heliostats operate in double-axis tracking mode. The receiver absorbs the heat into a heat transfer medium (e.g. molten salt), typically transfers the heat to water to produce steam and drive a turbine to generate power. The advantage of these point focused systems is that they can operate at higher temperatures than line focused systems and so produce higher temperature (higher grade) steam, which allows greater efficiencies and more energy storage per unit mass of molten salt. Increasing project capacity increases economies of scale up to a point, most notable in terms of steam turbine efficiency with scale, but also in production of the various elements such as Heliostats. Once the heliostat array gets large, challenges emerge in terms of being able to accurately focus on the tower from a greater distance, necessitating more robust supports and potentially more accurate controls / positioners.

4.4.2 Recent trends

Historically the majority of CST installations have been linear parabolic trough type, and as of 2010, a total installed base globally of 1.2GW, increasing to 1.9GW by early 2012. Project scale continues to increase with typical projects as large as 700MW and 17.5 hours of storage[51]. A 2023 project in UAE (Noor 1) is notable in terms of scale as it incorporates 2 x 200MW parabolic trough facilities alongside a 100MW tower installation and 250MW of 'traditional' PV.

[51] https://arena.gov.au/assets/2019/01/cst-roadmap-appendix-1-itp-cst-technology.pdf

Numerous solar tower installations have taken place over the last 10 years or so across a number of jurisdictions, including Morocco, Chile and China, with power outputs and energy storage durations in the ballpark rough order of magnitude of the scale proposed for the "hypothetical project" below.[52]

The installed capacity of CST remains relatively small compared with conventional PV, at circa 7GW globally by 2023, with growth to these levels promoted by incentives in the main historical markets being USA and Spain, and new developments in other geographies such as the Middle East and China. China is increasingly focused on CST and has developed hybrid projects complementing CST with traditional PV and wind generation. This approach is seeing more widespread adoption over time as it allows for wind and solar to be directly exported to the grid, meaning more of the CST output can be directed to storage for time-shifting to other times of day.

Due to the lack of existing CST facilities in Australia, the Australian Solar Thermal Research Institute (ASTRI) recently commissioned Fichtner to complete a study on CST in the Australian context[53]. The study included development of a cost model for different plant configurations which breaks the project cost down into three high level elements being the solar field, thermal energy storage and power block. They chose a hypothetical location on the mid-coast of NSW for their reference case.

From a technical perspective, alternative approaches to CST are emerging as a result of the drive for cost reduction and efficiency gains. The Vast Solar approach out of Australia seeks to leverage a greater number of smaller towers with corresponding smaller heliostat arrays, as well as using liquid sodium instead of molten salt. Sodium melts at a much lower temperature of 98°C which is a range at which trace heating is effective, meaning the medium can be readily re-melted if required. Other approaches include heat transfer through falling particles in place of the more 'traditional' molten salt, or heat collection in heat blocks such as carbon.

As storage durations have tended to increase with CST deployment over time this has flowed through to higher capacity factors for CST installations, now exceeding 50% for 8 hours storage[54]. As a result of this and the 'hybridisation' of generation (complementing with PV and wind), CST costs dropped by more than 60% between 2010 and 2020[55].

The International Energy Agency forecast dramatic growth in CST, 10-fold through to 2030 and then a further 4-fold increase to 2040 (281GW)[56].

Little public information is available in terms of asset retirement for CST given the relatively small and recent installed base. However, it is proposed that, for a solar tower configuration, there should be options for metal recycling for the tower construction itself (provided it is made of steel) and also for the support structures and tracking mechanisms for the heliostats. The heliostats themselves may be more challenging to recover materials from given the typical combination of metal with glass coating. Over time and assuming the market grows as anticipated by IEA, it is expected there will be similar recycling requirements imposed by state or federal jurisdictions, as has been the case for End-Of-Life PV panels. As this takes place, and as the number of heliostats reaches a critical mass, it will also promote focus on and development of recycling facilities, and with market competition, it is reasonable to also expect a progressive reduction in recycling costs.

4.4.3 Retirement scenario

The selected hypothetical project is a standalone concentrating solar tower with solar field capacity of 720 MWt and net electrical capacity of 140 MW AC via a steam cycle. The plant utilises molten salt as heat transfer fluid capable of 14 hours of storage.

Table 34 Retirement scenario configuration – CST

Item	Unit	Value	Comment
Configuration			
Technology		Solar Tower with Thermal Energy Storage	Based on typical options and recent trends with single central tower or multiple towers, storing

[52] The Australian Concentrating Solar Thermal Value Proposition, Fichtner Australia, Oct2023
[53] The Australian Concentrating Solar Thermal Value Proposition, Fichtner Australia, Oct2023
[54] **Life cycle assessment (LCA) of a concentrating solar power (CSP) plant in tower configuration with different storage capacity in molten salts - ScienceDirect**
[55] **irena_renewable_heat_generation_costs_2010_to_2020.pdf**
[56] **Concentrated solar: An unlikely comeback? — RatedPower**

Item	Unit	Value	Comment
			energy during the day and generating for 14 hours through evening peak and overnight period e.g. 5pm to 8am.
Solar field capacity	MWt	720	
Thermal energy storage	MWth	4,667	14 hours of storage
Power block		1 x Steam Turbine, dry cooling system	
Net capacity	MW	140	Based on typical options and recent trends, 140 MW with 14 hours thermal energy storage is selected.
Power cycle efficiency	%	45	Typical
Heat transfer fluid		Molten salt	Molten salt is currently the preferred heat transfer fluid for central tower CST technology
Storage	Hours	14	As mentioned in Section 4.5.3, almost all recent projects have a thermal energy storage component. 14 hours was chosen as representative.
Storage type		2 tank direct	
Storage description		Molten salt	
Performance			
Total plant size (Gross)	MW	150	25°C, 110 metres, 60%RH

4.4.4 Cost estimates

Retirement key assumptions

The following assumptions have been considered in reviewing the Retirement, Disposal and Recycling costs:

- The retirement cost estimates are expected to be to an Order of Magnitude level.
- There appears little public available data regarding retirement of CST assets, given both the relatively small installed base and the age of that installed base.
- To develop an estimate for retirement costs, analogies have been drawn and calibrated against. For example:
  - The structure of a steel tower for CST is expected to have a significantly greater quantity of steel than an equivalent tower for a large capacity wind turbine and the corresponding steel recycling value reflects this.
  - Similarly, retirement and recycling costs for a PV array can be used as a starting point for the retirement and recycling costs of heliostats, acknowledging the larger area associated with the heliostats, and the need for dual axis tracking, therefore:
    - An expectation of more robust support structures.
    - An assumption of slower removal rates per heliostat, given large size, mass and the need for structures to be cut into smaller sizes to be able to fit into shipping containers for removal off site.
    - Inclusion of concrete foundations for each heliostat, given the large size and windage for each heliostat, as opposed to a piled solution for PV.
  - Due to the significantly larger size, heliostats are assumed to cost twice as much as PV panels to recycle.
  - The steam system configuration aligns broadly with conventional thermal power plant infrastructure. However, the molten salt component lacks a direct analogue and is assumed to be a specialty chemical. Its disposal is expected to incur elevated costs, proportionate to its contribution to the overall system

CAPEX. According to NREL[57], molten salt comprises approximately 46% of the total installed cost of the thermal energy storage (TES) system. Fichtner[58] estimates TES costs at $167M, implying a molten salt cost of $77.1M. Applying a standard decommissioning allowance of 10% of CAPEX results in an indicative cost of $7.7M for the molten salt inventory.

– A paper[59] on the topic presents an example with approximately the same MWh capacity as the hypothetical case (smaller output offsetting larger duration) and so quantity figures have been used with respect to:
  - Solar field concrete, which has been subsequently calibrated (at a high level) for heliostat surface area, number of heliostats, and approximate height of the support structure (i.e. moment arm) for the hypothetical project, relative to the reference data.
  - Unalloyed steel listing for the solar field (assume to be for support structures for heliostats).
  - Steel for the tower section.
– Items will be transported 300km for recycling or disposal, which is an assumption considered reasonable given the remote nature of previously proposed CST facilities.
– As heliostats are generally glass coated steel, and the combination makes recycling challenging, and they are significantly larger in size per unit than a PV panel, it is assumed that the heliostats will be recycled at a cost of $30 per Heliostat, or double the allowance per PV panel.
– There is otherwise an allowance for scrap value in the support structures for the heliostats and the steel tower. There is also an allowance for scrap value for some components of the steam system and HV infrastructure, and similarly some value associated with redeployment of some components.
– At a high level the benefits from scrap value etc are roughly offset by the cost of heliostat recycling, with a net recycling cost of $3,000/MW.

Retirement process overview

The retirement of CST is expected to broadly include:

– Site establishment including site management team and vehicles.
– Electrical disconnection from the grid.
– Segmentation and removal of the tower and loading sections onto trucks for recycling of steel, subject to size and weight limits.
– Removal and purging of molten salt into transportable vessels for trucking to hazardous waste facility.
– Redeployment of elements of the steam / power system where suitable, and removal and disposal / recycling of other elements.
– Progressive removal of heliostats, cutting into manageable and transportable sizes and loading onto trucks for disposal/recycling.
– Removal of heliostat supports and tracking mechanisms for recovery of the steel scrap value.
– Removal of civil structures for disposal to landfill.
– Site demobilisation.

[57] https://www.nrel.gov/docs/fy12osti/53066.pdf
[58] The Australian Concentrating Solar Thermal Value Proposition, Fichtner Australia, Oct2023
[59] **Life cycle assessment (LCA) of a concentrating solar power (CSP) plant in tower configuration with different storage capacity in molten salts - ScienceDirect**

Retirement estimates

Retirement cost for the 140MW CST installation as contemplated in the hypothetical project, is estimated at $384,000 per MW.

It is expected that heliostat removal and recycling will pose a significant proportion of the total cost and so should be better investigated over time as data becomes available. Molten salt disposal cost should also be further investigated and (where cost remains high), seek opportunities to address this economically (or redeploy the product and avoid disposal costs). This could have material impact on overall retirement cost.

Net recycling revenue has been incorporated into the Retirement figure, as has disposal cost.

Table 35 Retirement estimate – CST

	Concentrated Solar Thermal
Decommissioning, Demolition & Rehabilitation Costs ($/MW)	$240,000
Disposal Costs ($/MW)	$141,000
Recycling Costs ($/MW)	$3,000
Retirement Costs ($/MW)	**$384,000**

Duration of retirement

It is estimated that retirement will take approximately 35 weeks. Critical path is assumed to be the heliostat removals, given the large number of large structures that need to be removed and dismantled, and at a measured pace. There is some overlap between the phases as listed below, which do not necessarily follow a linear sequence.

Table 36 Duration periods – CST

Activity	Duration (weeks)
Decommissioning	4
Demolition & Dismantling	31
Rehabilitation	2

4.5 Large Scale Battery Energy Storage System (BESS)

Large scale lithium-ion battery technology continues to be deployed for utility scale[60] facilities throughout Australia and the capacity base is increasing rapidly. GHD is aware of at least 30 large scale Battery Energy Storage System (BESS) facilities that have been constructed since the industry emerged in 2017 and across Australia hundreds of facilities are now in various stages of announcement, development or construction. With battery design life for the majority of OEM products at up to 20 years[61], it is expected that there will be significant volume of battery storage capacity that will be retired from 2035 onwards.

The modular nature of a BESS enables it to be sized separately for both power and energy requirements to meet varied project requirements. A typical standalone large-scale BESS consists of several components:

– Battery system.
– Battery management system.
– Power conversion stations (bi-directional inverters/converters).
– Step-up transformer(s).
– Power plant control system.
– Switch room / switchyard.
– Operations and balance of plant equipment.

4.5.1 Technology overview

"Lithium-ion" battery technology is a term which covers numerous sub-chemistries which in the Australian large scale BESS market have typically included:

– Lithium Nickel-manganese-cobalt oxide (NMC).
– Lithium nickel-cobalt-aluminium oxide (NCA).
– Lithium iron phosphate (LFP).

As the market has matured and LFP technology has shown safety advantages in relation to reduced propensity for thermal runaway, the LFP sub-chemistry is currently the preferred technology for most utility scale applications.

4.5.2 Recent trends

For storage duration, early BESS deployments favoured battery durations of 1 hour or less. Currently BESS facilities in Australia are typically looking at 2-4 hours duration[62] and now up to 8 hours duration[63]. This is largely driven by reductions in battery prices over time and the market which batteries operate in rewarding power price arbitrage. Outputs from recent developments have been in the hundreds of MW, including the AGL Liddell BESS (500MW/1000MWh), Stanwell (300MW/1200MWh), and Collie (first phase 219MW/877MWh).[64]

In terms of retirement costs, increasing the storage duration will increase the volume of batteries requiring recycling and / or disposal as well as balance of plant requirements (containers, HVAC, controllers etc.) for each facility. However, it would be expected that the unit cost (per MWh) for retirement would decrease with facility size increases due to some economies of scale.

Regarding retirement, it is likely that all of the current lithium-ion battery chemistries will be dealt with in a similar fashion, either needing assessment of individual modules or cells for potential repurposing or look to processing or disposal. Currently the lithium-ion recycling industry is emerging with ambition to reduce costs and improve material recovery. It is envisaged that processes to recycle lithium batteries will improve significantly over coming years due to the size of the opportunity[65] as will the ability for industry to handle larger volumes of batteries. Combined, it is expected that battery recycling costs should improve over current cost estimates.

[60] https://www.energysage.com/business-solutions/utility-scale-battery-storage/
[61] **Battery Energy Storage System (BESS).pdf**
[62] https://www.pv-magazine.com/2024/10/24/australia-has-7-8-gw-of-utility-scale-batteries-under-construction/
[63] https://au.rwe.com/projects/limondale-bess/
[64] https://www.pv-magazine.com/2024/10/24/australia-has-7-8-gw-of-utility-scale-batteries-under-construction/
[65] **Lithium-Ion Battery Recycling Market Size, Forecast 2025-2034**

Technology is now emerging that incorporates lithium-ion batteries with zero degradation guarantees for up to 3 years. Whilst still in its infancy, if this technology is able to economically reduce battery degradation and increase design life this could significantly delay retirement costs. GHD also notes that energy density of lithium-ion battery modules is increasing with time which means that associated balance of plant requirements is reducing per unit of MWh storage. Improved fire suppression within battery containers is also allowing tighter layouts with reduced footprint. Continuing these trends is likely to marginally reduce retirement costs particularly associated with balance of plant equipment and rehabilitation. As the BESS industry is in its infancy, it is expected that other developing battery chemistries, favouring cheaper and more recyclable materials, might also begin to encroach on the current lithium dominated market. However, all emerging chemistries would still be expected to require costs for recycling and / or disposal.

In terms of storage duration, early BESS deployments favoured battery durations of 1 hour or less. Currently BESS facilities are typically looking at 2-4 hours duration with a number of planned projects with 8 hours duration within the NEM[66]. This is largely driven by reductions in battery prices over time and the market which rewards energy arbitrage. In terms of retirement costs, increasing the storage duration will increase the volume of batteries requiring recycling and / or disposal as well as balance of plant requirements (containers, HVAC, controllers etc.) for each MW of installed capacity. However, it would be expected that the unit cost (per MWh) for retirement would decrease with increasing economies of scale.

Increasingly, BESS are being proposed to be co-located with other generation facilities, including solar PV and onshore wind. The option of DC coupling has potential to reduce duplication of inverter equipment with potential to further reduce land area requirements and associated cabling which could therefore reduce overall retirement costs.

GHD also notes that grid forming BESS technology which allows the provision of inertia and system strength support is becoming far more prevalent, however, this capability does not significantly change equipment requirements and therefore is not expected to have significant impact on BESS retirement costs.

4.5.3 Retirement scenario

The selected retirement scenario is a stand-alone lithium-ion battery with capacity of 200 MW AC. This review has investigated storage durations of 1hr, 2 hr, 4 hr and 8 hr in line with industry trends towards longer duration batteries, as the cost per MWh continues to decline.

Table 37 Retirement scenario configuration – BESS

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Technology		Li-ion				
Power Capacity (gross)	MW	200				
Energy Capacity	MWh	200	400	800	1,600	
Auxiliary power consumption (operating)	kW	1,700	1,900	2,400	3,500	Indicative figures (highly variable, dependent on BESS arrangement, cooling systems etc.).
Auxiliary power consumption (standby)	kW	300	600	1,200	2,400	Indicative figures (highly dependent on BESS arrangement, cooling systems etc.).
Power Capacity (Net)	MW	198.3	198.1	197.6	196.5	
Seasonal Rating – Summer (Net)	MW	198.3	198.1	197.6	196.5	Dependent on inverter supplier.
Seasonal Rating – Not Summer (Net)	MW	198.3	198.1	197.6	196.5	

[66] World's biggest eight-hour lithium battery wins NSW long duration storage tender | RenewEconomy

4.5.4 Cost estimates

Retirement key assumptions

The following high level key assumptions were made in consideration of retirement of BESS technology:

- Cost estimates for battery retirement are to AACE Class 5 level.
- Estimate for the 1-hour case was based on internal reference data for 1-hour battery similar order of magnitude of power output.
- Estimates for longer duration batteries were based on assumed scaling of the elements of the cost buildup that are correlated with energy storage quantity (e.g. number of battery modules) but not those elements which scale more with power output (fixed in this case) or those which are fixed costs.
- 50% of the mass of copper cabling (including insulation) has been assumed to be recoverable as copper metal.
- 50% of the recoverable copper is tied to the AC side (power delivery) – and so constant across the scenarios considered. The remaining 50% is assumed to be on the DC side and therefore proportional to the total quantity of energy storage (which differs from case to case).
- Recycling value is assumed to be limited to the copper cabling, which is assumed to be saleable at a price which is at the midpoint of a publicly available published range[67].
- It is assumed that the battery is located in relatively close proximity to a site for disposal and site for recycling (i.e. relatively close to a population centre, <100km), which is not unreasonable for a standalone BESS facility.

Retirement process overview

The retirement of BESS will broadly include:

- Site establishment including site management team and vehicles.
- Electrical disconnection from the grid.
- Progressive disconnection of battery modules and lifting via cranes on to trucks for disposal.
- Removal of cabling and recovery of copper for recycling where economical.
- Removal of civils structures for disposal to landfill.
- Site demobilisation.

Retirement estimates

Retirement cost for the BESS scenarios considered are presented in Table 38. It is worth noting that a significant proportion (21-31%) of the retirement cost is allocated to battery disposal – this represents an opportunity, should cost-effective recycling approaches be developed, or alternatively if there is an end user willing to give depleted batteries a second life, for example in exchange for a much lower cost than a new facility.

Table 38 Retirement estimate – BESS

	200MW/1hr	200MW/2hr	200MW/4hr	200MW/8hr
Decommissioning, Demolition & Rehabilitation Costs ($/MW)	$28,000	$41,000	$76,000	$128,000
Disposal Costs ($/MW)[68]	$7,000	$14,000	$27,000	$55,000
Recycling Costs ($/MW)[69]	($4,000)	($6,000)	($9,000)	($17,000)
Retirement Costs ($/MW)	**$31,000**	**$49,000**	**$94,000**	**$166,000**

[67] **Latest scrap metal prices | What is your scrap metal worth?**
[68] Positive value indicating this element has caused an increase in the Retirement Costs as shown
[69] Negative value indicating this element has resulted in a reduction in the Retirement Costs as shown

Duration of retirement

Asset retirement is estimated to take place over 16 weeks (for 1- and 2-hour installations) and 32 weeks (for 4- and 8-hour installations), plus an allowance for site mobilisation and demobilisation of up to 4 weeks. It has been assumed that, for larger battery installation, the number of crew members and equipment items could be increased up to a point, and beyond that, it could make sense to increase the duration rather than manage a high number of concurrent work fronts,

Table 39 Duration periods – BESS

Activity	200MW/1hr Duration (weeks)	200MW/2hr Duration (weeks)	200MW/4hr Duration (weeks)	200MW/8hr Duration (weeks)
Decommissioning	2	2	2	2
Demolition & Dismantling	16	16	32	32
Rehabilitation	2	2	4	4

4.6 Distribution Connected BESS

Distribution connected BESS has an advantage over utility scale as its generally connected closer to the end user. This can result in deferred expenditure on upgrades of transmission infrastructure such as HV transmission lines, HV transformers and substations. Systems with storage capacity of less than 5MW can also face fewer regulatory hurdles particularly in terms of network connection. Even at an anecdotal level the installed base of utility scale battery technology is generally increasing, and this trend extends to distribution scale BESS, albeit there is limited discrete data currently available.

4.6.1 Technology overview

In Australia, a large majority of distribution connected BESS are lithium-ion batteries with various sub-chemistries being utilized. Although there is limited discrete data available at distribution scale, the same principles hold true as for utility scale, where LFP is now the preferred chemistry for distribution-connected facilities. This preference is driven by lower cost and a reduced likelihood of thermal runaway. While lower energy density can be a disadvantage of LFP, this is a less material consideration for stationary applications.

4.6.2 Recent trends

The trends noted for large scale BESS (as described in Section 4.5.2) are generally consistent for distribution scale BESS. The emerging lithium-ion BESS recycling industry, largely driven by utility scale facilities, will also benefit distribution scale operations. It's expected that processes to recycle lithium batteries will improve significantly over coming years due to the size of the opportunity[70] which will drive economies of scale as well as innovation.

Trends at distribution scale are similar to those for large scale, with respect to working towards zero degradation guarantees, higher densities, and improved designs in terms of fire suppression. As with large scale facilities, distribution connected BESS are increasingly being proposed to be co-located with other generation facilities, including solar PV, with potential for DC coupling and therefore savings in inverters, land and cabling. This could therefore reduce overall retirement costs for a co-located facility; however, retirement estimates for co-located facilities are not considered in this Report.

4.6.3 Retirement scenario

The selected retirement scenario is a stand-alone lithium-ion battery with capacity of 5 MW AC. For simplicity this review has considered a single storage duration of 2 hours.

Table 40 Retirement scenario configuration – BESS

Item	Unit	1 hour	Comment
Technology		Li-ion	
Power Capacity (gross)	MW	5	
Energy Capacity	MWh	10	
Auxiliary power consumption (operating)	kW	42.5	Indicative figures (highly variable, dependent on BESS arrangement, cooling systems etc.).
Auxiliary power consumption (standby)	kW	7.5	Indicative figures (highly dependent on BESS arrangement, cooling systems etc.).
Power Capacity (Net)	MW	4.96	
Seasonal Rating – Summer (Net)	MW	4.96	Dependent on inverter supplier.
Seasonal Rating – Not Summer (Net)	MW	4.96	

[70] **Lithium-Ion Battery Recycling Market Size, Forecast 2025-2034**

4.6.4 Cost estimates

Retirement key assumptions

The key assumptions are similar in nature to those presented for the large-scale BESS as detailed above, namely:

- Cost estimates for distribution connected BESS retirement are to a AACE Class 5 level.
- Estimate for the 2-hour storage capacity case was based on internal reference data for a 1-hour battery.
- 50% of the mass of copper cabling (including insulation) has been assumed to be recoverable as copper metal.
- Recycling value is assumed to be limited to the copper cabling, which is assumed to be saleable at a price which is at the midpoint of a publicly available published range[71].
- It is assumed that the battery is located in relatively close proximity to a site for disposal and site for recycling (i.e. relatively close to a population centre, <100km), which is not unreasonable for a standalone distribution connected BESS facility.

Retirement process overview

As with larger scale facilities, retirement of BESS will broadly include similar types of elements, albeit scaled back as appropriate:

- Site establishment including site management team and vehicles.
- Electrical disconnection from the grid.
- Progressive disconnection of battery modules and lifting via cranes on to trucks for disposal.
- Removal of cabling and recovery of copper for recycling where economical.
- Removal of civils structures for disposal to landfill.
- Site demobilisation.

Retirement estimates

Retirement cost for a 5MW / 2-hour distribution connected BESS is estimated at $136,000 per MW of power output. Due to the limited scale of the facility, overheads represent a proportionately higher share of total retirement costs. Although advancements in recycling technologies may offer modest cost reductions, they are not a primary focus at this scale. More material cost drivers include site management and equipment hire. Opportunities for cost optimisation include leveraging economies of scale through concurrent retirement of co-located or nearby BESS and solar PV assets.

Table 41 Retirement estimate – distribution connected BESS

	5MW / 2hr
Decommissioning, Demolition & Rehabilitation Costs ($/MW)	$129,000
Disposal Costs ($/MW)[72]	$17,000
Recycling Costs ($/MW)[73]	($10,000)
Retirement Costs ($/MW)	**$136,000**

[71] **Latest scrap metal prices | What is your scrap metal worth?**
[72] Positive value indicating this element has caused an increase in the Retirement Costs as shown
[73] Negative value indicating this element has resulted in a reduction in the Retirement Costs as shown

Duration of retirement

Asset retirement is estimated to take place over 3 weeks, plus an allowance for site mobilisation and demobilisation of up to 2 weeks. This total of 5 weeks is approximately 25% of the duration for the 200MW installation (which is 40x larger), however, there are practical limitations to how much time on site can be compressed. The significantly longer time onsite (per MW) translates to significantly higher fixed costs per MW and therefore overall a significant increase in retirement cost per MW as can be seen above.

Table 42 Duration periods – BESS

Activity	5MW/1hr Duration (weeks)
Decommissioning	1
Demolition & Dismantling	3
Rehabilitation	1

4.7 Onshore wind

Wind farms are one of the most prevalent forms of renewable energy in the world and are a major part of Australia's energy mix. Modern operating or in construction wind farms comprise large horizontal axis wind turbines with a hub height typically ranging from 100-165 m, and with blade diameters up to the order of 180 m. Both hub height and blade diameter are dictated by site-specific characteristics such as topography, mean and extreme wind speeds, wind shear, and site constraints (such as transportation limitations or planning approval conditions). Sites with a strong wind resource (mean wind speed above 8 m/s) are more likely to target lower hub heights and smaller diameter turbines, while sites with lower wind resource (mean wind speed 6-8 m/s) are inclined to maximise both hub height and blade diameter to produce an economically attractive prospect from a lower wind resource site.

In addition to the wind turbines themselves, wind farms consist of internal access roads, hardstands, substation/s, internal electrical distribution (e.g. buried cables, overhead lines, or both), operations and maintenance facilities, and supporting infrastructure such as storage, fencing and security.

4.7.1 Technology options

Typical utility scale wind farms have between 20-150 wind turbines and associated infrastructure. Smaller wind farms may be developed in specific circumstances such as off-grid remote power systems for mining or other activities, and projects with over 150 turbines may be seen on occasion, though these are often divided into multiple stages for deliverability and commercial appeal.

Increasingly, wind farms are co-located with solar farms and energy storage (such as lithium-ion BESS) for energy dispatch flexibility and system strength support, which would typically be located proximate to the main wind farm substation and connection point.

While hub height and blade length will vary based on specific characteristics of the site, the overall process for decommissioning will be consistent across these options. Older wind farms with smaller turbines may present an opportunity for smaller cranes and supporting equipment, which in turn may present a less complex and less logistically challenging retirement project, however the key steps, activities, and overall cost prospect (on a $/MW basis) is anticipated to be similar.

4.7.2 Recent trends

Within the last decade, modern wind turbines have increased in size, both physically and on a MW capacity basis, from the order of 2-3 MW to 6-8+ MW per turbine. This trend has been driven by technology improvements aimed at reducing costs (per MW) for wind farms in general, as well as improvements aimed at capturing lower quality wind resource (i.e. increased hub height and greater blade diameter). This trend is generally continuing, however limitations around transportation and logistics (e.g. transport envelopes, crane lifting heights) are leading to a slowing or plateauing of this trend of increased turbine size and capacity.

The Australian wind turbine market is still currently dominated by European or North American manufacturers (e.g. Siemens Gamesa, Vestas, GE Vernova, and Nordex), however increasingly Asian manufacturers (e.g. Goldwind, Envision) are aiming to enter and serve the growing appetite for wind turbines.

At the same time, market pressures are encouraging manufacturers to reduce their scope in wind farm projects to supply-only (including installation) contracts, with civil and electrical balance of plant and overall project management being managed by separate subcontractors, owners, or project management specialists. This represents a general shift away from the 'one-stop-shop' approach of EPC contracts, which is becoming increasingly challenging due to international market and supply chain pressures.

Retirement of wind farms has not been carried out widely in Australia due to the age of the wind assets in operation. Some early wind farms have reached the end of their technical life and have been retired, however many more will be reaching this point over the next decade.

The main materials used are cast iron, steel, copper, aluminium, fibreglass epoxy and rare earth magnets with neodymium and dysprosium. While much of the material within a wind farm is recyclable (in the order of 85-94%

according to Clean Energy Council[74]), there is still a notable portion that is not recyclable or not able to be recycled in a cost-effective manner such as the nacelle cover and turbine blades, thereby resulting in disposal (such as in landfill). Wind turbine blades in particular are difficult to recycle, being made of composite materials that cannot easily be recycled or reused. Some options considered for wind turbine blades include:

– Repurposing the blades for use such as bus stops, playground equipment, displays at campuses, etc.
– Mechanical chopping or grinding of the blades to break the material up into smaller pieces that can be used for applications such as road base, aggregate, or further processed to recover some of the base materials.
– Innovative methods, such as chemical technologies that can break down resins to recover useful materials within the blade construction.

With wind farm decommissioning in its infancy in Australia, these repurposing or blade recycling facilities and supply chains are not presently available. Until such facilities are available and become cost-effective to operate, blades are likely to be sent to landfill for disposal. Notwithstanding, interest and scrutiny in this area is leading to research, development and innovation, such as Siemens Gamesa's RecyclableBlade technology[75] in Spain and Vestas blade circularity initiatives[76] in Denmark, which are both looking at resins used in blade construction to create fully or largely recyclable turbine blades.

4.7.3 Retirement scenario

Current wind turbines being put forward for projects for onshore projects range up to the order of 8 MW, with projects installed in recent years (or currently being installed) ranging from 5-7+ MW. Smaller wind turbine options may be selected in specific circumstances, however the strong trend in the industry is for projects to target these industry-leading sizes and models.

The V162-6.2, rated at 6.2 MW nameplate capacity, as presented in the *2024 Costs and Technical Parameters Report*[77], is considered to be suitable and typical of a wind turbine being implemented on several projects currently under development or construction. Other similar turbine models, such as those offered by GE, Goldwind, Nordex, and Siemens Gamesa, have a similar decommissioning process and cost.

Table 43 Retirement scenario configuration – onshore wind

Item	Unit	Value	Comment
Technology / OEM	-	Vestas	Other options include GE, Goldwind, Nordex, Siemens Gamesa, etc.
Make model	-	V162-6.2	Based on current recent installations
Unit size (nominal)	MW	6.2	Nameplate rating
Number of units	-	100	-
Total plant size (Gross)	MW	620	-

[74] https://cleanenergycouncil.org.au/getmedia/b009dae0-2964-4da7-807f-09c59ab04052/recycling-and-decommissioning-of-renewable-energy-tech.pdf
[75] https://www.siemensgamesa.com/global/en/home/explore/journal/recyclable-blade.html
[76] https://www.vestas.com/en/sustainability/sustainability-product-offerings/blade-circularity
[77] https://aemo.com.au/-/media/files/major-publications/isp/2025/aurecon-2024-energy-technology-costs-and-technical-parameter-review.pdf?la=en

4.7.4 Cost estimates

Retirement key assumptions

The following specific considerations and assumptions have been made in the development of the retirement cost presented in this document for onshore wind.

- The cost estimate for wind farm retirement is considered to be to AACE Class 5 level.
- Labour and equipment costs for the duration of retirement, including a suitably sized main crane plus additional cranes for support and other activities.
- Dismantling of wind turbines via one main crane crew, with components lowered to ground, dismantled as required, and transported from site for disposal or recycling.
- The main crane crew is assumed to move sequentially from turbine to turbine dismantling the main wind turbine components, which are then further dismantled and transported from site for disposal or recycling.
- One main crane crew is assumed to take four working days to dismantle one wind turbine.
- Wind turbine foundations assumed to be left in place, with grading carried out to achieve slopes consistent with surrounding land.
- Cables are assumed to be buried to a depth greater than 1m and left in situ.
- Roads are left in place for future use.
- Disposal and recycling facilities assumed to be within two hours of the project site, with disposal of clean waste.
- The wind farm has a single central substation, with power reticulation within the wind farm via buried cables.
- Turbine hardstands (nominally 40m x 80m) are assumed to be excavated to a depth of 200mm with material disposed of as clean waste.
- Hardstand areas to be covered in topsoil to a depth of 150mm.
- Allowance made for seeding of hardstand areas.
- Nominal allowance included for ongoing care of seeding and revegetation in initial period following decommissioning.
- Much of the material in a wind farm can be recycled, with significant salvage value being found in the steel that makes up tower sections and in the copper and other valuable metals that are present. The salvage value is based on recovery of steel in the wind turbine tower sections and base plate, as well as recovery of the copper and aluminium content contained within the wind farm.
- Recoverable steel is based on the tower weights of a wind turbine with a hub height of 150 m, with an assumed recovery rate of 100% for tower steel.
- Tower sections are assumed to be cut into transportable sizes that do not require special transportation allowances such as oversize over mass vehicles, police escort, road closures, or temporary route adjustment works.
- Recoverable copper is based on a ratio of 1 kg copper to 85 kg steel[78], with an assumed recovery of 80%.
- Recoverable aluminium is based on a ratio of 1 kg aluminium to 85 kg steel[79], with an assumed recovery of 80%.
- Value of steel, copper, and aluminium is included at rates of $200/t, $7,500/t, and $2,000/t respectively.

[78] Vestas, (2014). Life Cycle Assessment of Electricity Production from an onshore V117-3.3 MW Wind Plant – 6 June 2014, Version 1.0. Vestas Wind Systems A/S, Hedeager 42, Aarhus N, 8200, Denmark.
[79] Vestas, (2014). Life Cycle Assessment of Electricity Production from an onshore V117-3.3 MW Wind Plant – 6 June 2014, Version 1.0. Vestas Wind Systems A/S, Hedeager 42, Aarhus N, 8200, Denmark.

Retirement process overview

The process for retirement an onshore wind turbine is broadly consistent with the reverse of the construction process. Large cranes are required to dismantle the turbines themselves, while smaller cranes and other construction equipment is used to dismantle, decommission, transport, and dispose/recycle the materials.

Supporting infrastructure such as roads may be decommissioned or left in place for ongoing activities (such as farming, or general access), and infrastructure (such as cables) may be removed or left in place (assuming suitable burial depth).

Associated infrastructure such as operations and maintenance facilities, offices, stores and storage, substation and other electrical equipment, and fencing, must be removed and disposed of or recycled.

Impacted land such as turbine hardstands and foundations for ancillary infrastructure are cleared, covered with topsoil, and re-seeded or revegetated in accordance with the rehabilitation plan, development approval or lease requirements, or other obligations.

With farmland typically leased from existing landowners, other specific requirements may be imposed on a wind farm through these lease agreements, however this will vary based on landowner preference or requirements and must be considered on a project-specific basis. It will also depend on the conditions of the planning approvals specific on the retirement phase.

A significant portion of wind farm materials can be recycled, in particular steel, copper, and other metals, resulting in a salvage value that can partially offset the cost to decommission the wind farm.

The typical process for retirement an onshore wind farm is described at a high level as follows.

– Disconnection and isolation of the wind farm from the grid.
– Procurement and mobilisation of equipment and crews, including large cranes, construction vehicles and decommissioning compound.
– Main crane crew will dismantle turbines sequentially, dismantling the turbine components in reverse order of construction, lowing them to the ground, further dismantling for transportation, and transport offsite for disposal or recycling.
– Wind turbine blades are assumed to be broken down at each turbine location and transported offsite for disposal in a manner consistent with other general construction waste (though at a higher disposal cost per tonne).
– Prior to dismantling, turbines are safely locked in position in accordance with manufacturer instructions, drained of all liquids and fluids (e.g. cooling, hydraulic and lubricating fluids, oils), and safely de-energised.
– Given the requirement for main crane access for dismantling, wind farm roads and turbine hardstand areas will need to be in suitable condition to allow access and operation of this heavy equipment. Given crane access is not frequently needed throughout the operating life of a project, this access and infrastructure may not have been maintained to suitable levels, which could result in additional preparation work at each location to facilitate this process.
– Hardstand areas (namely wind turbine hardstands, but also operation and maintenance and other ancillary infrastructure pads) are covered with topsoil, graded to a suitable finished level, and then re-seeded or revegetated.
– Foundations are typically left intact in the ground, with the area graded to achieve a suitable finished level consistent with the surrounding area. If foundations are slightly protruding above the ground, they may have to be cleared and levelled with the ground surface.
– Smaller foundations, such as those for buildings, facilities, electrical equipment, and other ancillary equipment is removed and disposed.

Retirement estimates

Retirement cost for the 620 MW onshore wind farm contemplated in the retirement scenario is estimated at $152,000 per MW. The retirement costs are the total costs net of any salvage value. Disposal costs and recycling benefit are the cost for disposing material and salvage value from recycling material respectively and are included in the overall retirement cost.

Table 44 Retirement estimate – onshore wind

	Onshore Wind
Decommissioning, Demolition & Rehabilitation Costs ($/MW)	$181,000
Disposal Costs ($/MW)	$4,500
Recycling Costs ($/MW)	($24,500)
Retirement Costs ($/MW)	**$152,000**

Duration of Retirement

The duration of retirement of a wind farm is heavily dependent on several factors such as the number of main crane (i.e. cranes capable of dismantling the wind turbines themselves) crews mobilised for the exercise, terrain complexity, site prevailing wind resource (for the main crane operation), conditions of hardstands and internal roads, and turbine hub-heights. This is similar to what is found for wind farm construction projects, where for instance multiple main cranes implemented on a project can reduce overall construction time. These cranes are typically in high demand and are expensive to hire and mobilise, and so the trade-off between time and cost must be considered. Refer to the Retirement Key Assumptions for assumptions guiding the duration of retirement.

Retirement duration is estimated in Table 45.

Table 45 Duration periods – onshore wind

Activity	Duration (weeks)
Decommissioning*	67
Demolition & Dismantling*	
Rehabilitation	4

*Note – decommissioning activities are assumed to occur concurrently with demolition and dismantling of WTGs.

4.8 Offshore wind

As of June 2024, there is approximately 75 GW of offshore wind deployed globally with Offshore Wind Farms (OWF) in operation across Asia, Europe and North America[80]. Offshore wind is a promising generation technology in Australia, with projects proposed in Victoria, New South Wales, Tasmania and Western Australia. It is important to note that at the date of this Report, there are no OWF in construction or operation in Australian State or Federal waters.

OWFs generally comprise the wind turbines which capture wind energy, standing on a tower which may be fixed directly or floating and anchored to the seabed. Wind turbines are connected via a cable array to an offshore substation that then exports power via a transmission cable to an onshore substation and grid network.

4.8.1 Technology options

OWF technology has evolved significantly over the last 20 years, offering various options to optimize efficiency and sustainability. Some of the main technology options available to developers in 2025 are summarised below:

– Fixed-bottom turbine foundation: The most common offshore wind turbines, anchored to the seabed in shallow waters (up to 60 meters deep), typically using either monopile or jacket structures.
– Floating turbine foundation: Designed for deeper waters where fixed-bottom structures are impractical. These turbines are anchored using mooring lines and can harness stronger, more consistent winds.
– Advanced blade technology: Innovations in blade materials and design improve efficiency, durability, and energy capture, reducing maintenance costs.

Each technology option will impact the retirement process and cost. Fixed or floating will affect how the OWF is decommissioned, in terms of vessels used, port facilities and the range of activities required (refer to Section 5.1.4). New blade materials will affect how they are disposed of or recycled.

4.8.2 Recent trends

In response to developer interest in OWF in Australia, the Federal Government selected six declared areas for priority offshore wind development:

1. Gippsland, Victoria.
2. Southern Ocean, Victoria.
3. Hunter, New South Wales.
4. Illawarra, New South Wales.
5. Bass Strait, Tasmania.
6. Indian Ocean off Bunbury, Western Australia[81].

The Federal Government is in the process of receiving applications and awarding feasibility licenses for proposed projects in each declared area. The Victorian areas in Gippsland and Southern Ocean (near Port Fairy) are the most advanced with 12 feasibility licenses granted to proponents such that investigations can be advanced to inform individual projects.

Retirement is currently the default option where developers are required by national and local regulation to remove all OWF components and restore the seabed to is pre-construction condition. In Australia, OWF licence holders must remove all infrastructure and make good any damage caused at the windfarms end of life[82]. There is currently no defined framework on the process that retirement should follow and to date very few commercial scale OWFs have been retired, which makes an estimation of cost based on any precedent a difficult task. From a range of industry studies, it is expected that vessel costs will represent 60% to 80%[83] of project decommissioning costs

[80] Global Offshore Wind Report, Global Wind Energy Council, June 2024
[81] https://www.dcceew.gov.au/energy/renewable/offshore-wind/areas
[82] https://www.dcceew.gov.au/energy/renewable/offshore-wind/offshore-wind-facts#offshore-wind-farms-will-be-fully-decommissioned-at-the-end-of-their-life
[83] End of Life Planning in Offshore Wind, ORE CATAPULT, April 2021

and so developers will need to encourage flexibility in their timeframes to be able to avoid peak periods of high vessel demand as this cost will be directly influenced by competitive market forces.

A range of complications exist when considering OWF retirement including high logistical costs to complex seabed conditions. The oil and gas sector are currently facing higher than expected costs for retiring platforms due to initial under-estimates of costs and limited planning.

Key trends that will impact retirement costs include:

– **Larger turbines:** Developers are deploying turbines with higher megawatt capacities, increasing efficiency and reducing costs per unit of energy. By 2030, turbines will be 15-20 MW in size compared to 1-3 MW in the early days of offshore wind.
– **Expanded rotor diameters:** Bigger blades capture more wind energy, improving overall performance.
– **Taller towers:** Higher towers allow turbines to access stronger, more consistent winds, boosting energy generation.

These trends will increase retirement costs, particularly for fixed OWF as larger vessels will be required to dismantle them offshore and transport to suitable ports. Larger components will also require bigger temporary storage sites prior to their disposal/recycling of materials.

A decommissioned turbine, similar to onshore wind turbines, consists of various materials as outlined in Section 4.7.2. Blades are typically made from a combination of glass- and carbon-fibre in epoxy- or polyester-based resin matrices, along with polyethylene terephthalate (PET) or balsa foam. At the root end, there are steel inserts to provide bolted connection to the blade bearing. Other than this, there is typically a copper-based lightning protection system. Currently, blades are typically cut up and either sent for burning (in waste to energy or district heating plant) or to landfill. It is likely, however, that cost-effective recycling methods will emerge by the time substantial offshore wind turbine retirement is undertaken in Australia.

Foundations can be fully or partially removed. There is some evidence showing that partial removal of foundations protects the ecosystems that have developed around these foundations[84]. However, the Offshore Infrastructure Regulator in Australia has published a draft guideline *Preliminary Information – Preparing a Management Plan*[85] in 2024, which states that "licence holders should plan toward full removal of licence infrastructure and include this as a consideration in decommissioning planning and estimation of financial securities" while accepting that the final decommissioning concept may not be finalised until a later stage.

Most foundations and substation topsides typically have high steel content, so can be broken down and recycled as input to the manufacture of new steel components. Some substation components may be re-used and others can be recycled. The cable conductor can be readily processed and reused in a range of sectors, and crosslinked polyethylene (XLPE) may be cleaned, dried and ground and recycled as filler for new power cables or as insulation in lower voltage cables or accessories.

The disassembling of wind turbine components into the different materials can be a difficult task, making complete recycling a challenge. It has been estimated that as a best-case scenario, nearly 20%[86] of the decommissioning costs could be paid for by recycling offshore wind turbines on projects with monopile foundations. Although this figure could be considered overly optimistic, it is high enough that recycling of components remains an attractive possibility. In addition, as the volatility of scrap metal prices have significant impacts on the decommissioning costs, these could help determine when it would be best to schedule a decommissioning activity to take advantage of high scrap prices.

[84] Critical considerations in partial decommissioning of offshore wind farms include residual liability and biodiversity trade-offs, European Commission.
[85] Preliminary Information – Preparing a Management Plan, Offshore Infrastructure Regulator
[86] Recycling Offshore Wind Farms at Decommissioning Stage, E. Topham, D. McMillan, S. Bradley,

4.8.3 Retirement scenario

Two hypothetical retirement scenarios have been selected, one based on fixed turbine foundations (1200 MW wind farm) and one based on floating turbine foundations (432 MW wind farm). These two examples can be considered typical sizes for OWFs currently in development or construction in European waters and likely to extend to future projects based in Australia. Refer to Table 46 and Table 47 for scenario details.

The 12 MW offshore wind turbine is likely outdated as of 2025; however it is still relevant for the purpose of presenting retirements costs per MW as is the focus of this report.

Table 46 Retirement scenario configuration – offshore wind (fixed)

Item	Unit	Value	Comment
Technology / OEM	-	GE	Other options include Vestas, Goldwind, Siemens Gamesa, Mingyang, etc.
Make model	-	Haliade-X 12 MW	
Unit size (nominal)	MW	12	12 MW European average turbine order capacity 2022
Number of units	-	100	Typical for fixed-bottom offshore wind farms
Total plant size (Gross)	MW	1200	

Table 47 Retirement scenario configuration – offshore wind (floating)

Item	Unit	Value	Comment
Technology / OEM	-	GE	
Make model	-	Haliade-X 12 MW	
Unit size (nominal)	MW	12	12 MW European average turbine order capacity 2022
Number of units	-	36	Typical for floating offshore wind farms
Total plant size (Gross)	MW	432	

4.8.4 Cost estimate

Retirement key assumptions

The following assumptions have been considered in preparing retirement costs:

Fixed foundation

– The retirement cost estimates are expected to be to an order of magnitude level.
– Water depth at site: 30 m.
– Distance of OWF to shore, grid, port: 60 km.
– OWF component disposal to nearest suitable port.
– Seabed infrastructure removed to 1 m below seabed (full removal).
– Consistent good weather conditions exist throughout retirement process (no weather downtime / or time contingency).

Floating foundation

- The retirement cost estimates are expected to be to an order of magnitude level.
- Water depth at site: 100 m.
- Distance from OWF to shore, grid, port: 60 km.
- Floating substructure material and type: steel semi-submersible.
- Mooring system: 3-point mooring with drag embankment anchors.
- OWF component disposal to nearest suitable port.
- Consistent good weather conditions exist throughout retirement process (no weather downtime / or time contingency).

Retirement process

The retirement of an OWF will consist of numerous offshore activities at different locations, utilising high-cost vessels and equipment, where the impact of inefficient planning and sequence of work performed will result in higher costs. Typical main drivers for OWF retirement are as follows:

- Availability and range of selection of vessels (which give a range of day rates, including mobilisation/demobilisation costs).
- Quantity and size of turbines to be removed, which will define the vessel selection and also project and contract strategy suitable to maximise cost-effectiveness.
- Depth, weight and type of foundation which may limit the range of vessel types and thus higher rates.
- Marine support, port fees and fuel.
- Offshore workability.

Fixed foundation

The retirement of fixed foundation OWF will broadly include:

- Removal of individual blades, then hub and nacelle then finally the tower.
- For monopile or jacket foundations, all elements above the seabed will need to be removed with piles cut off at an agreed height (typically 1m below the top of the seabed).
- Removal of foundations likely involving the use of a work-class Remotely Operated Vehicle (ROV) fitted with a range of cutting and drilling tools.
- Removal of array and export cables, where the value of the main conductor material is worthwhile retrieving rather than leaving the cable buried.
- Removal of the offshore substation.

Floating foundation

The retirement of floating foundation OWF will broadly include:

- The floating offshore wind turbine is disconnected from the mooring lines and cables at site and towed to port for wind turbine and floating substructure disassembly.
- Mooring lines are disconnected from the floating substructure, then disconnected from anchors. Where the connection to the anchor is not accessible, the mooring line may be cut and any buoyancy modules, clump weights and load-reduction devices are removed.
- Removal of anchors (depending on their type and the commitments made in the decommissioning plan).
- Removal of subsea cables and cable accessories.
- Removal of floating offshore substations.

Retirement estimates

Fixed foundation

Recent OWF cost models derived by the UK's CATAPULT organisation (independent owned technology innovation and research centre for renewable energy) through a number of research programmes have estimated a total retirement cost of 330 GBP/kW[87] ($604 AUD/kW based on an exchange rate of 1 GBP = $1.83 AUD in 2019) for an OWF of comparable size to the retirement scenarios considered in this Report. It should be noted that this cost is based on 2019 prices.

A report commissioned by the government of Belgium in 2023 analysed the retirement costs and recycling benefit at nine OWFs in Belgium[88]. The capacity-weighted average cost per kW is 421 € ($690 AUD considering 2023 exchange rate of 1 EUR = $1.65 AUD) minus 58 €/kW ($96 AUD) for recycling benefit, considering all materials and components (full removal).

Based on these two sources, the retirement cost equates to 650 AUD/kW and represents approximately 15% of CAPEX if it is based on the CAPEX cost ($4,306 AUD/kW) stated in the Aurecon report *2024 Energy Technology Cost and Technical Parameter Review*[89]. Note that this estimate has considered full foundation removal and no weather downtime in the retirement campaign.

The ratio of retirement to CAPEX for OWFs may be higher than other generation technologies. This is explained by the offshore nature of the retirement, which requires specialised heavy lifting vessels. Also, it is worth noting that offshore wind has typically a higher capacity factor than onshore wind and solar PV, so the retirement cost ratio to energy produced would be closer to the other technologies rather than the retirement cost per capacity.

Please note that the retirement costs do not consider contingencies nor indirect costs.

Table 48 Retirement estimate – offshore wind (fixed)

	Fixed Offshore Wind
Decommissioning, Recycling & Rehabilitation Costs ($/MW)	$650,000
Disposal Costs ($/MW)	$3,000
Recycling Benefit ($/MW)	($96,000)
Retirement Costs ($/MW)	**$557,000**

[87] Guide to an Offshore Wind Farm, ORE CATAPULT / The Crown Estate, January 2019
[88] [88] Belgium Offshore Wind Farms Decommissioning Costs Project, FPS Economy, December 2023
[89] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024

Floating foundation

Recent OWF cost models derived by the UK's CATAPULT organisation (independent technology innovation and research centre for renewable energy) through a number of research programmes have estimated a total decommissioning cost of 150 GBP/kW[90] for a 450 MW floating (comparable size to the selected hypothetical floating foundation project).

This decommissioning cost equates to $275 AUD/kW (based on an average exchange rate of 1 GBP = $1.79 AUD in 2023) and represents approx. 3.5% of CAPEX if it is based on the CAPEX cost ($7,724 AUD/kW) stated in the Aurecon report *2024 Energy Technology Cost and Parameter Review*[91]. The same assumptions are used for recycling benefit and disposal costs as for fixed-bottom, noting that the floating blade, tower, cable and foundation mass are comparable to fixed-bottom.

Table 49 Retirement estimate – offshore wind (floating)

	Floating Offshore Wind
Decommissioning, Recycling & Rehabilitation Costs ($/MW)	$275,000
Disposal Costs ($/MW)	$3,000
Recycling Benefit ($/MW)	($96,000)
Retirement Costs ($/MW)	**$182,000**

The difference in retirement process for fixed bottom and floating offshore wind is significant and reflected in the varied cost per MW, with fixed bottom requiring each component to be disassembled piece-by-piece out at sea, using jack-up vessels with heavy lifting equipment. Floating systems, meanwhile, require the turbines and floating foundations to be towed to port for disassembly. This allows for a simpler and faster process to remove the towers, nacelles and blades with cranes at the port, which is more cost efficient than out at sea.

Duration of retirement

Minimising the length of the retirement operations is important to reduce costs, but the time taken for the process will vary with the type of vessel chartered, the disassembly technique and the number of lifts used, as well as the transportation strategy. Water depth is a key factor, because deeper water requires longer monopiles, which makes operations more difficult and will have a direct impact on the foundation design and weight of the project to be decommissioned. In addition, these processes rely on good consistent weather conditions.

Table 50 Global track record of decommissioning of OWFs

OWF	Country	Year Commissioned	Year Decommissioned	Number of WTGs	WTG Capacity (MW)	Retirement duration per WTG (days)
Vindeby	*Denmark*	*1991*	*2017*	*11*	*0.45*	*8.2*
Lely	*Netherlands*	*1992*	*2016*	*4*	*0.5*	*N/A*
Utgrunden	*Sweden*	*2000*	*2018*	*7*	*1.5*	*5.6*
Yttre Strengrund	*Sweden*	*2001*	*2016*	*5*	*2*	*N/A*
Blyth Demonstrator	*United Kingdom*	*2006*	*2019*	*2*	*2*	*11.6*

There is very limited global experience of decommissioning of fixed-bottom OWFs, as shown in the table above[92]. The decommissioned projects are also of a small scale, so it is expected that larger projects will benefit from economies of scale, reducing the decommissioning duration from those shown in the above table. This aligns with estimates from the UK's Catapult, which estimates 5.5 days per turbine for decommissioning[93].

[90] Guide to a Floating Offshore Wind Farm, ORE CATAPULT / The Crown Estate, May 2023
[91] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024
[92] The Wind Farm End-of-Life Question: how decommissioning projects will impact global capacity targets, Spinergie, 2023
[93] End-of-life planning in offshore wind, ORE Catapult / the Crown Estate, 2021

There is no real track record for decommissioning floating OWFs. However, as the decommissioning process is essentially the reverse of the installation process, and the installation of floating OWFs may be less susceptible to weather downtime than the installation of fixed bottom OWFs, it is possible that decommissioning of floating OWFs has a shorter duration than decommissioning of fixed-bottom OWFs. A range of 3-6 days per turbine would be reasonable for decommissioning of floating WTGs.

The table below provides an estimate for the relevant retirement duration, pertaining to retirement, for the two retirement scenarios discussed in this section.

Table 51 Duration periods – offshore wind

Activity	Fixed Foundation Duration (weeks)	Floating Foundation Duration (weeks)
Decommissioning*	*63*	*19*
Demolition & Dismantling*		
Rehabilitation	*4*	*1*

*Note – decommissioning activities are assumed to occur concurrently with demolition and dismantling of WTGs.

4.9 Pumped hydro

Hydroelectricity is a globally proven technology which has been implemented for over a century and currently is the largest source of renewable energy globally. Pumped Hydro Energy Storage (PHES) utilises the same principal as conventional hydropower for generation but utilises a second reservoir below the power station enabling water to be captured so as to be pumped back to the upper reservoir.

When energy is abundant and therefore lower in cost, water is pumped from the lower reservoir to the upper reservoir where is it stored. At times when energy is in demand and therefore higher in cost, water flows back down to the lower reservoir generating power. The hydro plant may be either using reversible pump turbines or separate pump and turbine on the same shaft (unidirectional). PHES facilities compliment variable wind and solar energy sources providing storage at scale during times of high energy production from these sources, then providing dispatchable energy when these sources are in short supply. It currently has the greatest energy storage capacity globally providing over 90% of all energy storage[94].

Key elements and equipment making up a typical PHES scheme are described in Section 4.9.1.

PHES may also be referred to as Pumped Storage Plant (PSP), Pumped Storage Hydropower (PSH), Pumped Hydro Storage (PHS), Pumped Storage or Pumped Hydro.

4.9.1 Technology options

The layout and requirements of a PHES scheme are dependent on geography, geology and site characteristics hence almost all are bespoke designs to suit the location. Given this it is not possible strictly to provide a typical scheme, but it is the case that shorter duration smaller facilities are being developed by the private sector while the public sector typically support or build longer duration larger schemes that the private sector typically avoid given greater levels of development risk.

Privately developed PHES projects in Australia currently range typically within 500-1000MW output with a storage duration of 8 to 12 hours. The schemes are typically a closed loop system with off stream upper and lower reservoirs with purpose-built dams. These relatively small reservoirs would be generally suitable for recreational use if no longer viable as PHES, although often the catchments may not be sufficient to maintain the design full supply level.

Government led PHES projects in Australia currently range between 1000-2000MW output with longer duration storage of up to 24 hours. These schemes typically utilise an existing large reservoir requiring an additional reservoir with purpose-built dam for storage. Where these larger schemes utilise an existing asset, there is typically a requirement that environmental flows are maintained. Using an existing water asset means that there will little to no rehabilitation cost for the reservoir and inundation areas of the scheme.

There are currently no schemes within the Australian market in planning for long duration storage up to 48 hours. Although the Snowy 2.0 project under construction has an output of 2.2GW with 156hrs storage, although this is achieved through using supply from large existing reservoirs that are part of a larger interconnected series of hydropower stations rather than a standalone pump hydro scheme.

The majority of both private and government schemes comprise an underground powerhouse complex and waterways. Key elements and equipment within a PHES scheme are:

– Upper reservoir and dam with intake and emergency spillway.
– Lower reservoir and dam with intake and spillway.
– Lower outlet and return intake including gate and rubbish / debris separation and collection racks.
– High pressure waterways: tunnel or penstock for water conveyance between upper reservoir and powerhouse with surge tank or chamber as required.
– Low pressure waterway: tunnel or penstock for water conveyance between the powerhouse and lower reservoir with surge tank or chamber as required.
– Powerhouse cavern: containing pumps-turbines-motor/generators and auxiliaries, switchgear and generator connections, draft tubes and gates, cranes for plant erection and maintenance and balance of plant (BOP).

[94] **https://www.hydropower.org/factsheets/pumped-storage**

- Transformer cavern: containing transformers and cranage, switchgear and HV connections.
- Evacuation, ventilation and cable tunnels: these may be combined or separate dependent on scheme size and format.
- Main access tunnel: tunnel to provide primary access to the underground powerhouse complex.
- Switchyards and transmission lines: high voltage switching and grid connection.
- Access roads to the site (including temporary and permanent roads).

4.9.2 Recent trends

As the need for grid stability and dispatchable energy increases with the expansion of variable renewable generation technologies proponents are exploring longer duration storage options. This has resulted in numerous projects under development globally with increasing output and storage. In the current Australian market projects are typically within in the 500MW to 1000MW with an 8-12 hours storage, however projects in early phase development with a view to the future are looking for greater outputs from 750MW to 1500MW with greater value placed on storage between 10 to 16 hours.

Some projects aim to utilise existing public reservoir assets through government programs which endeavour to encourage private development. These projects are effectively a closed loop storage system with requirements for ongoing environmental releases into the catchments. Employing an existing asset, which in Australia are typically owned by a public sector water utility, means that there will be minimal to no obligation and cost for rehabilitation for the reservoir and PHES retirement.

Unlike the three extant PHES schemes in Australia, the majority of PHES projects being developed feature underground waterways and powerhouse complex with fixed speed reversible Francis turbines, as sites are selected which favour this type of machine, being the most cost-effective combination of head, power and reservoir level range over a complete generation cycle. As the key elements of the schemes are largely underground, with the access portals and shafts being sealed, there is minimal surface rehabilitation in comparison to a surface powerhouse and penstocks which would require greater land rehabilitation and disposal costs.

There is potential for recycling and repurposing of the equipment within the powerhouse, dependant on service life. Pumps, valves, heat exchangers, compressors and transformers have potential to be refurbished for onward sale while ferrous and non-ferrous materials from gates, BOP and cables can be recycled reducing retirement cost.

Currently there are no examples of PHES proposed for retirement, globally or in Australia, limiting access to precedence or data sets that provide insight to cost trends for the retirement of a scheme. As PHES schemes have a long design life and large development CAPEX there is a trend to upgrade, increase efficiency and rehabilitate existing schemes to extend the life of the asset.

4.9.3 Retirement scenario

Three hypothetical projects have been selected for review being 500MW/10h, 2000MW/24h and 2000MW/48h. Even though there are no 48 h schemes being developed or existing in Australia, and the difference between a 24 h and 48 h scheme is only the size of the reservoirs, the 24 h scheme was extended to 48 h for comparison.

The layout of the scheme powerhouse and waterways is based on typical unit sizing for the scheme output which in turn influences the main plant number and size as well as the water conveyance tunnels. The parameters for each are:

– 500MW/10 hours scheme:
  - 2 x 250MW reversible Francis turbines.
  - 1 x power intake and outlet structures.
  - 1 x power waterway and tailrace.

– 2000MW/ 24 and 48 hours scheme:
  - 6 x 333MW reversible Francis Turbines.
  - 2 x power intakes and outlet structures.
  - 2 x power waterway and tailrace.

Table 52 Selected retirement scenarios – PHES

Item	Unit	10 hours	24 hours	48 hours	Comment
Fixed speed reversible Francis units	No.	2	6	6	250MW units for scheme <1000MW 333MW units for scheme >10000MW
Power Capacity (gross)	MW	500	2,000	2,000	Current projects under development in Australia range from 100 to 2,400 MW
Energy Capacity	MWh	5,000	48,000	96,000	Current projects in the private sector in Australia are under 10 hours of storage however trends are increasing to longer duration with 24 hours for government led projects.
Powerhouse configuration	Type	Underground	Underground	Underground	The majority of projects in developed in Australia utilize underground powerhouses.
Power Waterways	No.	1	2	2	Underground, as above.
Tailrace	No.	1	2	2	Underground, as above.
Transmission	km	15	15	15	Overhead 330kV transmission
Switchyard	No.	1	1	1	At PHES Site

4.9.4 Cost estimates

Cost estimates were developed for the retirement for the three scenarios as defined in Section 0 and assumptions in Sections 0.

Cost estimates have been developed in line with the methodology provided in Section 2.2. There is little to no data available on PHES retirement globally due to the longevity of the schemes. Therefore, a bottom-up approach has been used to develop the cost estimate using estimated quantities with unit rates for the works required to dismantle plant, material disposal and rehabilitation of the site.

The recycling value has been estimated with the same bottom-up approach using market rates for salvageable materials and equipment. The unit rates applied have been taken from market rates used in similar industries and equivalent activities in the construction of PHES in Australia.

Retirement key assumptions

As there is limited data or examples on the retirement of PHES globally the following assumptions have been made to support the basis for the cost estimate:

- The retirement cost estimates are expected to be to a AACE Class 5 level.
- All reservoirs are to be retained for community benefit, firefighting water and support of catchment management. No dam removal or inundation area rehabilitation costs are considered. It is assumed ownership and management including safety obligations for the dams and reservoirs will be transferred to a third party where dams are to remain at no cost to retirement.
- All rehabilitation of reservoirs and inundation areas have been excluded based on the assumption that reservoirs are to be retained. This includes dewatering, demolition and removal of dam embankment sections, excavation, haulage and disposal of dam fill materials and reseeding of the reservoir area.
- The cost associated with any requirement to fill any voids or reservoirs with water post-retirement has not been included.
- All schemes are assumed to be underground waterways, shafts, tunnels and caverns, commensurate with current Australian projects in development and recent trends.
- All intakes are horizontally arranged and are to be plugged and sealed but remain within the reservoir.
- All underground shafts and tunnels to be plugged and sealed prohibiting human access but remain in situ.
- All portals, waterways, shafts and tunnels are to be plugged with in-situ mass concrete of 5m thickness. No allowance has been made for the backfilling of underground tunnels as scheme elements are located within competent geology.
- Underground powerhouse is not required to be backfilled as all portals, shafts, waterways and tunnels are to be capped for further access. Therefore, no allowance has been made for haulage and disposal of fill material within the powerhouse.
- All surface elements are to be removed and recycled where possible. This includes substation, switchyards, offices and workshops. The switchyard is included in the demolition and recovered land will be levelled and rehabilitated. It is assumed only minor levels of contamination are to be addressed in the soil.
- Transmission route from network to the scheme is to be decommissioned and dismantled with elements to be recycled or salvaged where possible. Transmission tower foundations are to be removed and levelled.
- All roads that are serviceable for the operation of the scheme are to be transferred to local government or other relevant authority at no cost to scheme retirement.
- Burial of inert non-recyclable materials in underground voids and limited offsite disposal required.

It is worth noting that more than any other technology, key elements of PHES schemes can have a material impact on retirement costs per MW. As reservoirs are assumed to be retained in this retirement scenario, the below are not allowed for in the cost estimates, however, consideration for site-specific assets should be given to:

- **Dam removal:** the removal of dams is a complex process which can vary greatly depending on dam height, area and project complexity, with dam height typically being the greatest factor. A majority of dams in PHES schemes connected in the NEM are expected to be 10m in height or greater where the cost for removal increases significantly.
- **Reservoir liner:** the removal and disposal of reservoir liners. Depending on the reservoir type, liners are likely to be required to provide an impermeable barrier. As part of decommissioning and removal of the reservoir the liner would need to be removed and disposed to allow for rehabilitation of the inundation zone.
- **Rehabilitation of inundation zone:** On draining and removal of liner, rehabilitation of the inundation zone to re-establish the native vegetation would be required. Rehabilitation of these large areas is a time-consuming activity increasing costs and retirement timeline.

Retirement process

The retirement of PHES will require decommissioning of waterways and plant before dismantling of the powerhouse can proceed. Dewatering of the system needs to be undertaken so that the waterways can be permanently isolated at the intakes and then the main plant in the powerhouse decommissioned.

On completion of removal of underground plant the cavern can be used for disposal of inert material as a result of surface demolition and rehabilitation. Upon completion of disposal and rehabilitation works the access portals and shafts can be sealed against human access.

The high-level process for retirement of PHES will include:

- Isolation of power waterways.
- Dewatering of power waterways.
- Decommissioning of plant within powerhouse.
- Plugging and sealing intake structures. Removal of intake gates.
- Dismantling and removal of non-embedded components of main plant and balance of plant in powerhouse and transformer caverns.
- Dismantling and removal of surface plant including transmission lines and switchyard in parallel with underground works.
- Removal of foundations and complete rehabilitation of surface works.
- Disposal of non-recyclable inert materials within underground cavern.
- Plugging and sealing of shafts and tunnels with reinforced mass concrete plugs.

Retirement estimates

The cost for retirement for the three PHES schemes, described in Section 0 are summarised in Table 53. The retirement costs for these three schemes are listed in Section with the key assumption influencing retirement cost being that the reservoirs to be retained and transferred to the local authority eliminating the requirement for rehabilitation and ongoing post closure care.

Table 53 Retirement estimate – PHES

	500MW/10hours	2GW/24hrs	2GW/48hrs
Decommissioning, Demolition & Rehabilitation Costs ($/MW)	$9,000	$6,500	$6,500
Disposal Costs ($/MW)	$4,000	$2,000	$2,000
Recycling Costs ($/MW)	($2,500)	($1,500)	($1,500)
Retirement Costs ($/MW)	**$10,500**	**$7,000**	**$7,000**

Duration of retirement

The table below provides an estimate for the relevant retirement duration, pertaining to retirement, for the three hypothetical PHES schemes.

As the assumption is made that the reservoirs are to remain post-retirement there will be little to no difference between 24 hour and 48 hours storage due to the generation elements which are to be retired being of equal number and proportion.

Table 54 Duration periods – PHES

Activity	500MW/10hours Duration (weeks)	2GW/24hrs Duration (weeks)	2GW/48hrs Duration (weeks)
Decommissioning	13	26	26
Demolition & Dismantling	26	52	52
Rehabilitation	13	26	26

4.10 Electrolysers – PEM and alkaline

In an electrolyser cell, electricity causes dissociation of water into hydrogen and oxygen molecules. An electric current is passed between two electrodes separated by a conductive electrolyte or "ion transport medium", producing hydrogen at the negative electrode (cathode) and oxygen at the positive electrode (anode). The cell(s), and electrical, gas processing, ventilation, cooling and monitoring equipment and controls are contained within the hydrogen generator enclosure. Gas compression and feed water conditioning and auxiliary equipment may also be included.

Demineralized water is introduced into the electrolyser stack. Depending on the operational pressure, either a low-pressure water pump or a high-pressure water pump is used to inject demineralised water into the electrolyser stack. Upon supplying power to the stack, hydrogen and oxygen gases are produced. The hydrogen is subsequently directed to a deoxygenation unit to eliminate any trace amounts of oxygen, followed by a hydrogen dryer to remove any residual water vapor.

Additional units supplied as part of the electrolyser packages are typically:

– Stack power supply: AC/DC rectifier, DC voltage transducer and DC current transducer.
– Water circulation system: two phase filter and recirculation filter, inlet water tank, oxygen separator tank, injection pump, recirculation pump, piping, valves and instrumentation.
– Cooling equipment.
– Process control system.

A demineralisation package is required to deliver water of suitable quality to the electrolyser, and compressors are required to compress hydrogen from the electrolyser to the desired pressure for storage or transport. Hydrogen storage is important because electrolysers rarely operate continuously (operated when renewable power is available and/or cheap) but consumption patterns are often more continuous.

4.10.1 Technology overview

The following options exist commercially for electrolyser technology:

– Alkaline electrolysis, where the reaction occurs in a solution of water and liquid electrolyte (potassium hydroxide – KOH) between two electrodes. This is an established technology and has been in commercial operation for a number of decades.
– Proton Exchange Membrane (PEM) electrolysers use a solid polymer to split water into hydrogen and oxygen. Water enters the cell, and an electrical current separates it at the anode, producing oxygen, electrons, and positively charged hydrogen ions (protons). These protons pass through the membrane to the cathode, where they combine to form hydrogen gas. The system is built with layers that manage water flow, collect gases, conduct electricity, and keep the unit cool.
– Solid Oxide Electrolyser Cells (SOECs) are a newer type of commercially available electrolyser technology. They operate at higher temperatures than other technologies, using steam to improve efficiency. As a result, they require less electricity to produce hydrogen compared to traditional alkaline or PEM electrolysers. Leading suppliers of SOECs include Bloom Energy[95] and Topsoe[96].

4.10.2 Recent trends

The hydrogen industry, both in Australia and globally, has grown more slowly than expected. In Australia, ARENA funded three projects to build 10 MW electrolysers. Of these, only Engie's Yuri Renewable Hydrogen to Ammonia Project is on track for completion in 2025[97] and will become the country's largest electrolyser. AGIG's Hydrogen Park Murray Valley is also progressing, with operations expected in 2025[98].

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[95] An Efficient Electrolyzer for Clean Hydrogen - Bloom Energy. Website accessed 30/04/2025.
[96] Efficient SOEC electrolysis for green hydrogen production. Website accessed 30/04/2025.
[97] Australia's first large scale renewable hydrogen plant to be built in Pilbara - Australian Renewable Energy Agency. Website accessed 30/04/2025.
[98] Hydrogen Park Murray Valley – HyResource. Website accessed 30/04/2025.

Several large-scale projects have been cancelled or delayed due to financial challenges, including Fortescue's 500 MW Gibson Island project, the South Australian Hydrogen Jobs Plan including development of a 250 MW facility in Whyalla, South Australia[99], and the 3 GW H2-Hub Gladstone. Additionally, key proposals under the Hydrogen Headstart Program—such as H2Kwinana, Stanwell's Central Queensland Hydrogen Project, and Origin Energy's Hunter Valley Hub—are no longer proceeding. The 2025–26 Federal Budget did not provide further support for the hydrogen sector.

Slow progress in project delivery has stalled technology development, keeping costs high and limiting efficiency gains. Some OEMs claim step-change improvements, but these are not yet widespread. The emergence of SOEC technology may help reduce the levelised cost of hydrogen, particularly when paired with facilities that can supply excess steam. However, SOECs are less suited to variable operations due to their sensitivity to thermal cycling.

Efforts continue to improve hydrogen storage and compression technologies, as well as the production of hydrogen-derived fuels like ammonia, methane, and methanol. These can serve as both carriers and end-use products.

Greater electrolyser efficiency could lower cooling requirements and reduce the number and size of cell stacks, ultimately cutting retirement costs. Improved efficiency also reduces the scale of required renewable generation, easing pressure on upstream infrastructure. As electrolysers become more modular and Balance of Plant systems scale up, the retirement cost per MW is expected to decline—though current data is limited, and cost trends remain uncertain.

4.10.3 Retirement scenario

The selected retirement scenario is a 500 MW electrolyser facility for both Alkaline and PEM technology, both of which are comprised of 10 MW modules. Hydrogen storage and transport is not currently included as part of the retirement costs presented in Section 0.

Table 55 Selected retirement scenario – electrolysers

Item	Unit	PEM	Alkaline	Comment
Technology		Proton Exchange Membrane	Alkaline	
Unit size (nominal)	MW	10	10	Selected based on the range of currently available single stack sizes (or combined as stack modules). Up to 20 MW units are commercially available
Number of modules		50	50	
Hydrogen production (100% utilisation)	kg/h	8,333	9,091	Based on typical stack efficiencies for PEM and alkaline units
Operational capacity		70%	70%	
Compressors	kg/h	3 x 3,030	3 x 3,030	
Supply pressure	barg	30	1	
Discharge pressure	barg	100	100	

[99] Whyalla's Hydrogen Plant Plans Deferred for Steelworks. Website accessed 30/04/2025.

4.10.4 Cost estimates

Retirement key assumptions

There is limited real-world experience with retiring PEM or Alkaline electrolyser facilities. To date, only small-scale, standalone units have been built – no integrated large-scale plants (i.e. 500 MW) have been constructed or retired. As such, cost estimates for retiring large facilities remain theoretical.

Some insights can be drawn from decommissioning very small electrolyser units, though costs for these are often high relative to their capacity. Lessons from the chlr-alkali industry, particularly mercury-based plants, also offer parallels, especially regarding the handling of hazardous materials during retirement[100].

To guide the retirement cost estimates presented in this Report, the following assumptions have been made subsequent to the General Assumptions presented in Section 2.4:

– The retirement cost estimates are expected to be to an order of magnitude level.
– Post-retirement land use is assumed to be brownfield for industrial purposes.
– Limited information is available with regards to retirement costs for electrolyser facilities at present. According to the Electric Power Research Institute's (EPRI) Electrolysis Techno-Economic Analysis[101], a decommissioning cost of 10 % of the total plant cost may be assumed for a hydrogen production facility utilising electrolyser technology. Typical CAPEX is used to calculate the retirement costs using this assumption.
– The following components are included in Recycling estimate:
  - Steel that can be recycled, including from vessels, structural steel and from buildings. An estimated 88% of low-alloy steel and reinforcing steel can be recycled, while 100% of unalloyed steel can be recycled[102].
  - Copper from the facility (copper cabling) can be recycled.
  - Aluminium (from buildings and other structures) can be recycled.
  - For PEM units, the electrodes typically consist of platinum-group metals (platinum and iridium) or platinum-coated material, which can be recycled.
– Table 56 outlines the assumed volumes and recycling price for materials can be recycled, adjusted from a 5 GW facility to a 500 MW facility[103]. The midpoint of the ranges presented have been assumed as the volume of recyclable materials for the purposes of this Report.

Table 56 Assumed volumes and price of recycled materials for electrolyser retirement

Material	Estimated volumes (t)	Mid-point (t)	Recycling value ($/t)	% salvageable
Aluminium	400 – 2,660	1,530	$3,850	100
Copper	2,340 – 2,600	2,470	$15,000	80
Iridium (PEM only)	0.13 – 0.28	0.205	$230 M	76
Platinum (PEM only)	0.02 – 0.2	0.11	$46 M	76
Steel (various types)	9,370 – 23,500	16,435	$200	100

  - In the case of alkaline units, the salvaging of nickel may be considered but will be dependent on the nickel price. This is not currently included.

[100] Euro Chlor Publication. (August 2012). Guideline for decommissioning of mercury chlor-alkali plants.
[101] EPRI, Inc. (2025). Hydrogen Electrolysis Techno-Economic Analysis Tool. Home | Electrolysis Techno-Economic Analysis. Website accessed 30/04/2025.
[102] Khan. M. H. A. et. Al. (2024). Strategies for life cycle impact reduction of green hydrogen production – Influence of electrolyser value chain design. International Journal of Hydrogen Energy. 62 769-782.
[103] Teixeira, B., Brito, M.C. and Mateus, A. (2024). Strategic raw material requirements for large-scale hydrogen production in Portugal and European Union. Energy Reports 12 5133-5144.

Retirement Process Overview

The high-level process for retirement of an electrolyser facility is the following:

- Purge residual hydrogen and oxygen from the system using nitrogen, and depressurise.
- Drain electrolyte from the system and collect for disposal (particularly if alkaline).
- Isolate from power supply, water supply and external sources of gases.
- Dismantling and removal of water treatment and demineralisation units, as well as any water storage tanks on site and concrete bunding for storage tanks.
- Discharge water from cooling tower units (if used) to ground level and remove concrete foundations. Also remove pumps, piping and concrete foundations from cooling water pits. Alternatively dismantle and remove air cooling units.
- Remove and dispose high voltage (HV) transformers (including switchyard), demolish bunded area and remove foundations. Remove rectifiers and transformers for electrolysers and remove foundations.
- Remove electrolyser building cladding and steel structures.
- Disconnect electrolyser package piping and cabling, dismantle units into removable modules (electrolyser packages are typically constructed in modules with similar dimensions to shipping containers). Remove stacks from electrolyser units (if these are PEM units) for recovery of platinum-group metals. Remove electrolyser modules for salvaging of steel and other materials. Remove electrolyser building foundations. Dismantle compressors and remove. Remove foundations.
- Dismantle any hydrogen storage vessels and remove. Remove foundations.
- Fell charge administration building and warehouses to slab and remove foundations.

Retirement estimates

Retirement costs for electrolyser facilities have been estimated at around 10% of total CAPEX. For reference, indicative CAPEX values are approximately $2,630/kW for PEM electrolysers and $2,460/kW for Alkaline electrolysers[104,105,106]. These figures do not account for potential cost recovery through recycling of valuable materials during retirement. Based on this approach, retirement costs have been estimated using a rough order of magnitude as a proportion of overall plant CAPEX as presented in Table 57.

Table 57 Retirement estimate – electrolysers

	PEM	Alkaline
Decommissioning, Demolition & Rehabilitation Costs ($/MW)	$263,000	$246,000
Disposal Costs ($/MW)	$5,000	$5,000
Recycling Costs ($/MW)	($157,500)	($77,500)
Retirement Costs ($/MW)	**$110,500**	**$173,500**

Duration of retirement

Retirement of a 500 MW electrolyser facility is estimated to take up to 118 weeks.

Table 58 Duration periods – Electrolysers

Activity	Duration (weeks)
Decommissioning	20
Demolition	72
Rehabilitation	26

[104] 2024 Energy Technology Cost and Technical Parameter Review, Aurecon, December 2024
[105] Hubert, M. et. Al. (May 2024). Clean Hydrogen Production Cost Scenarios with PEM Electrolyzer Technology. DOE Hydrogen Program Record.
[106] Hinkley, J. et. Al. (March 2016). Cost assessment of hydrogen production from PV and electrolysis. Report to ARENA as part of Solar Fuels Roadmap, Project A-3018. CSIRO.

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