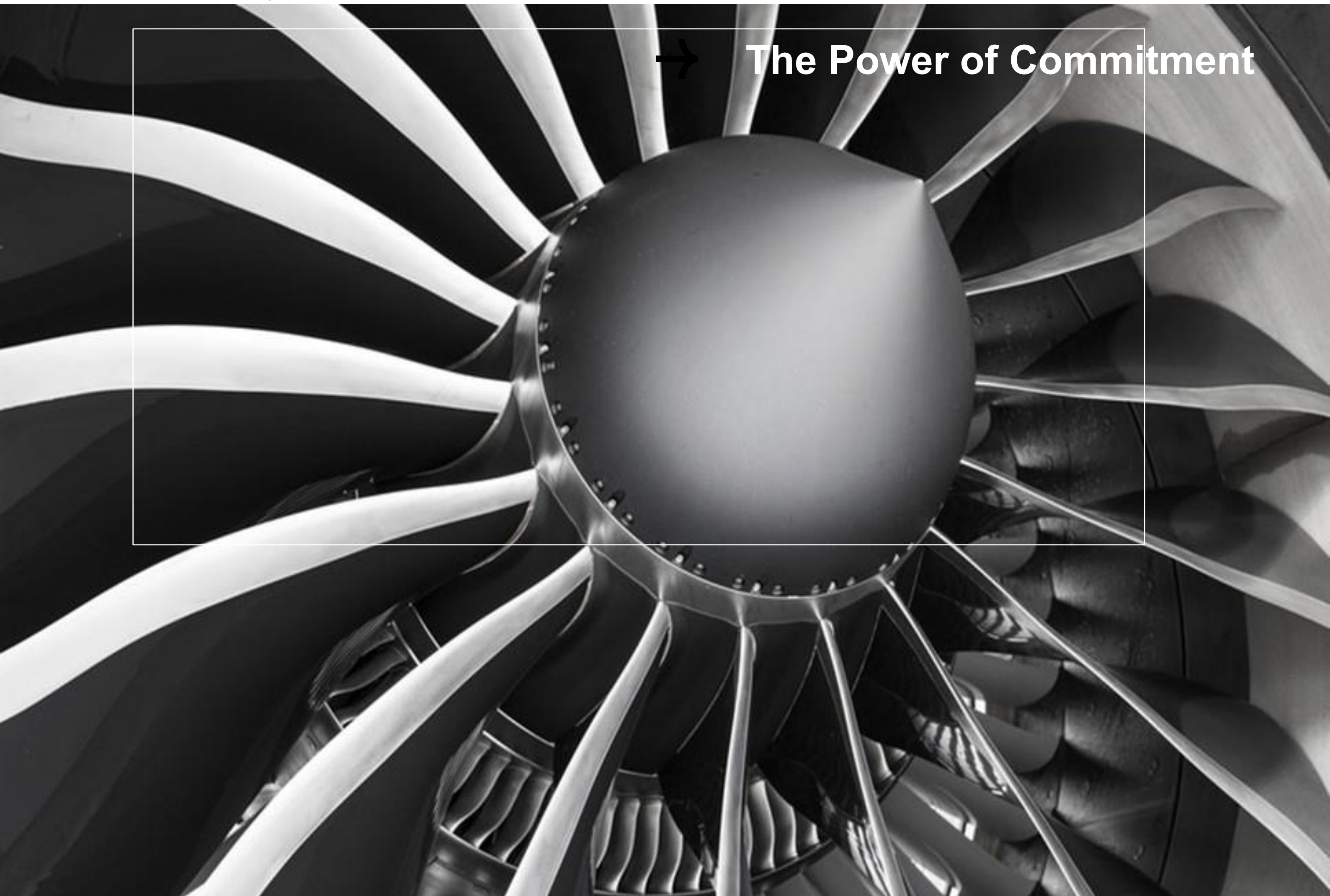
2025 Energy Technology Retirement Cost & O&M Estimate Review

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**		
			Name	**Signature**	**Name**	**Signature**	**Date**
S4	A	Various	G Conway P Baker		G Hatch		7/05/25
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

GHD Pty Ltd 39 008 488 373
Level 9, 145 Ann Street
Brisbane, Queensland 4000, Australia
T (07) 3316 3000 | **E** bne@ghd.com | **www.ghd.com**

The Power of Commitment

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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.

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[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.

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[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.

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[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].

[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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