# 2024 Energy Technology Cost and Technical Parameter Review

2024 Energy Technology Costs and Technical Parameter Review

## Australian Energy Market Operator

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Document prepared by:

**Aurecon Australasia Pty Ltd**

ABN 54 005 139 873

Ground Floor, 25 King Street
Bowen Hills QLD 4006

Locked Bag 331
Brisbane QLD 4001
Australia

**T** +61 7 3173 8000
**F** +61 7 3173 8001
**E** brisbane@aurecongroup.com
**W** aurecongroup.com



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| Name | Prabir Halder | Name | Paul Godden |
| Title | Lead Consultant | Title | Energy Leader, Queensland |

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# 1 Introduction

## 1.1 Background

The Australian Energy Market Operator (AEMO) is responsible for operating the National Electricity Market (NEM) in Eastern and South-Eastern Australia, and the Wholesale Electricity Market (WEM) in Western Australia.

AEMO's forecasting functions can influence the behaviour of existing generation assets and the economics and location of future investment and retirement decisions. These forecasts rely on various input assumptions.

AEMO has engaged Aurecon to review and prepare an updated set of generation and storage technology input data to be used in AEMO forecasting studies and to be published on the AEMO (and/or CSIRO) website.

The updated dataset includes current technology costs and technical operating parameters for both existing and emerging generation technologies, including those with minimal current local or international deployment. Hydrogen production, ammonia production, ocean and wave technologies, hydro-electric schemes and pumped hydro, and compressed air storage are also included.

The dataset is intended to be used by AEMO, and shared with industry, to conduct market simulation studies for medium and long-term forecasting purposes. This data will be then used in various AEMO forecasting publications.

## 1.2 Scope of study

The scope of this study was to prepare an updated set of costs and technical parameters for a concise list of generation and storage technologies, including the following:

- Onshore wind
- Offshore wind (fixed and floating)
- Large-scale solar photovoltaic (PV)
- Ocean and wave technologies
- Concentrated solar thermal with 16 hours energy storage
- Hydrogen-based reciprocating engines and gas turbines
- Combined-cycle gas turbine (CCGT) (with and without carbon capture and storage (CCS))
- Advanced ultra-supercritical coal fired power plant (with and without CCS)
- Biomass (biogas digesters, biomass generators using wood waste and biodiesel production)
- Waste to energy plant
- Electrolysers (PEM & Alkaline) – hydrogen production
- Fuel cells
- Battery Energy Storage Systems (BESS) with 1 to 48 hours storage
- Alternative battery technology such as large-scale iron flow battery storage
- Hydro-electric schemes and pumped hydro storage (10, 24 and 48 hours)
- Compressed air energy storage
- Estimated cost for large scale hydrogen storage
- SMR and SMR plus CCS (hydrogen production)
- Ammonia production
- Desalination plant

The parameters to be updated or developed include the following:

- Performance – such as output, efficiencies, production rate and capacity factors
- Timeframes – such as for development and operational life
- Technical and operational parameters – such as configuration, ramp rates, and minimum generation
- Costs – including for development, capital costs and O&M costs (both fixed and variable).

The updated dataset is provided in the accompanying Microsoft Excel spreadsheet (see Appendix A), the template for which was developed by AEMO. This report provides supporting information for the dataset and an overview of the scope, methodology, assumptions, and definition of terms used in the dataset and its development.

The intention is for the updated dataset to form a key input to the long-term capital cost curves in the 2024 GenCost publication to be prepared by CSIRO in conjunction with AEMO as well as other various AEMO forecasting publications such as the Integrated System Plan (ISP).

## 1.3 Abbreviations

**Table 1-1 Acronyms / abbreviations**

| Acronym | Definition |
|---|---|
| AC | Alternating circuit |
| CAES | Compressed Air Energy Storage |
| AD | Anaerobic Digestion |
| ADCP | Acoustic Doppler Current Profilers |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AFC | Alkaline fuel cell |
| APAC | Asia–Pacific |
| ARENA | Australian Renewable Energy Agency |
| ARF | Australian Renewable Fuels |
| AS | Australian Standards |
| ASTM | American Society for Testing and Materials |
| ASTRI | Australian Solar Thermal Research Institute |
| ASU | Air Separation Unit |
| AUD | Australian Dollar |
| AUSC | Advanced Ultra-supercritical |
| BESS | Battery Energy Storage System |
| bioSNG | bio-Synthetic Natural Gas |
| BNR | Biological Nutrient Removal |
| BOL | Beginning of Life |
| BOOT | Build-Own-Operate-Transfer |
| BOP | Balance of Plant |
| BPL | Biodiesel Producers Pty Ltd |
| C&I | Commercial and Industrial |
| CAES | Compressed Air Storage system |
| CAGR | Cooperative Research Centre |
| CAL | Covered Anaerobic Lagoon |

| Acronym | Definition |
| --- | --- |
| CAPEX | Capital Expenditure |
| CCGT | Combined-Cycle Gas Turbine |
| CCS | Carbon capture and storage |
| CCUS | Carbon capture utilisation and storage |
| CEC | Clean Energy Council |
| CFB | Circulating fluidised bed |
| CH4 | Methane |
| CHP | Combined Heat and Power |
| CIP | Cleaning in place |
| CNG | Compressed natural gas |
| $CO_2$ | Carbon Dioxide |
| COD | Commercial Operation Date |
| CPI | Consumer Price Index |
| CRC | Cooperative Research Centre |
| CST | Concentrated solar thermal |
| DBT | Dry Bulb Temperature |
| DC | Direct Current |
| DLE/DLN | Dry Low NOx |
| DMFC | Direct methanol fuel cell |
| DNI | Direct Normal Irradiance |
| EAC | East Australian Current |
| EDI | Electro deionization |
| EIS | Environmental Impact Statement |
| EMEC | European Marine Energy Centre |
| EPC | Engineer Procure and Construct |
| ESG | Environment, Social Governance |
| ESI | Energy Storage Industries |
| FAME | Fatty Acid Methyl Ester |
| FCAS | Frequency Control Ancillary Services |
| FEED | Front End Engineering and Design |
| FFA | Free Fatty Acid |
| FFI | Fortescue Future Industries |
| FFR | Fast Frequency Response |
| FGD | Flue Gas Desulfurization |
| FID | Final Investment Decision |
| FIT | Feed-in-tariff |
| FORCE | Fundy Ocean Research Centre for Energy |
| GHS | Geologic hydrogen storage |
| GJ | Gigajoule |
| GPS | Generator Performance Standards |
| GST | Goods and Services Tax |
| GT | Gas Turbine |
| GW | Gigawatt |

| Acronym | Definition |
|---|---|
| HAWT | Horizontal-axis wind turbine |
| HDPE | High density polyethylene |
| HHV | Higher Heating Value |
| HP | High Pressure |
| HRSG | Heat recovery steam generator |
| HTL | Hydrothermal liquefaction |
| HVAC | Heating, Ventilation, and Air Conditioning |
| HVO | Hydrotreated Vegetable Oil |
| IEA | International Energy Agency |
| IESO | Independent Electricity System Operator |
| IPCC | International Panel on Climate Change |
| IRENA | International Renewable Energy Agency |
| IRP | Integrated Resource Provider |
| ISCC | International Sustainability & Carbon Certification |
| ISP | Integrated System Plan |
| KHI | Kawasaki Heavy Industry |
| LCFS | Low Carbon Fuel Standard |
| LCNCC | Large Customer Negotiated Customer Connection |
| LCOA | Levelised Cost of Ammonia |
| LCOE | Levelised Cost of Electricity |
| LFP | Lithium Iron Phosphate |
| LHV | Lower Heating Value |
| LID | Light Induced Degradation |
| LTMA | Long Term Maintenance Agreement |
| LV | Low Voltage |
| MCR | Maximum Continuous Rating |
| MHF | Major Hazard Facility |
| MMC | Modular Multilevel Converter |
| MSW | Municipal Solid Waste |
| MV | Medium Voltage |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NCA | Lithium Nickel Cobalt Aluminium |
| NEG | National Electricity Grid |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| $NH_3$ | Ammonia |
| NMC | Lithium Nickel Manganese Cobalt Oxides |
| NOx | Nitric Oxide |
| NREL | National Renewable Energy Laboratory |
| NTP | Notice to Proceed |
| O&M | Operations and Maintenance |

| Acronym | Definition |
|---|---|
| OCGT | Open Cycle Gas Turbine |
| OEM | Original Equipment Manufacturer |
| OPEX | Operational Expenditure |
| OTEC | Ocean Thermal Energy Conversion |
| OWC | Oscillating Water Column |
| PAFC | Phosphoric Acid Fuel Cell |
| PEM | Proton Exchange Membrane |
| PEMFC | Proton Exchange Membrane Fuel Cell |
| PFR | Primary Frequency Response |
| PHES | Pumped Hydropower Energy Storage |
| PHS | Pumped Hydro Storage |
| PJ | Peta Joule |
| PPA | Power Purchase Agreement |
| PSH | Pumped Storage Hydropower |
| PSP | Pumped Storage Plant |
| PV | Photovoltaic |
| PVC | Polyvinyl chloride |
| RBESS | Residential Battery Energy Storage System |
| RDF | Refuse-derived Fuel |
| REZs | Renewable Energy Zones |
| RNG | Renewable Natural Gas |
| RO | Reverse Osmosis |
| RR | Recovery Ratio |
| RRB | Rolls Royce Bergen |
| RSC | Royal Society of Chemistry |
| RTE | Round Trip Efficiency |
| SAE | Simec Atlantis Energy |
| SAF | Sustainable Aviation Fuels |
| SAT | Single-axis Tracking |
| SCR | Selective Catalytic Reduction |
| SDG | Sustainable Development Goal |
| SDI | Silt Density Index |
| SIPS | Special Integrated Protection Scheme |
| SMR | Steam Methane Reforming |
| SOC | State of Charge |
| SOFC | Solid Oxide Fuel Cell |
| STATCOM | Static Synchronous Compensator |
| SWRO | Seawater Reverse Osmosis |
| TES | Thermal Energy Storage |
| TRL | Technology Readiness Level |
| UCO | Used Cooking Oil |
| USC | Ultra-supercritical |
| VNI | Victoria to NSW interconnector |

| Acronym | Definition |
|---|---|
| VPP | Virtual Power Plant |
| VRFB | Vanadium-redox Flow Batteries |
| WEM | Wholesale Electricity Market |
| WGS | Water-gas Shift |
| WLE | Wet Combustion System |
| WTG | Wind Turbine Generator |
| WWTP | Wastewater Treatment Plant |

# 2 Limitations

## 2.1 General

This report has been prepared by Aurecon on behalf of, and for the exclusive use of, AEMO. It is subject to and issued in connection with the provisions of the agreement between Aurecon and AEMO.

Power generation, energy storage, hydrogen and ammonia production conceptual design is not an exact science, and there are several variables that may affect the results. Bearing this in mind, the results provide general guidance as to the ability of the power generation facility, energy storage facility, or production facility to perform adequately, rather than an exact analysis of all the parameters involved.

This report is not a certification, warranty, or guarantee. It is a report scoped in accordance with the instructions given by AEMO and limited by the agreed time allowed.

The findings, observations, and conclusions expressed by Aurecon in this report are not and should not be considered an opinion concerning the commercial feasibility of such a project.

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## 2.3 Costs and budget

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# 3 Methodology and Definitions

## 3.1 Methodology

The dataset for the generation and storage technologies, and hydrogen and ammonia production technologies has been developed and updated based on a hypothetical project selected as being representative in 2024 for each examined technology, and which would or could be typically installed in the NEM as a market participant or energy consumer.

The size and configuration for each hypothetical project has been selected based on Aurecon's current experience with existing and recent / proposed new entrant power generation and storage projects in Australia, particularly in the NEM. For technologies that have not been deployed in Australia to date or only in demonstration applications, we have relied on international experience and published information for our assessment. The intent is that the technical and cost information developed for these hypothetical projects can be used as a basis by others with adjustment as needed for its specific purpose or project (i.e. scale on a $/MW basis within same order, inflate to account for location (regional or remote) cost factors, etc). There exist uncertainties on technology performance and cost estimates for new/emerging technologies, such as hydrogen, ammonia production, compressed air storage, etc.

The performance figures and technical parameters have been based on actual project information where available, or vendor provided information.

The cost estimates have been developed based on collating information from the following sources:

- Aurecon's internal database of projects – recently constructed or under development or construction
- Recent bid information from competitive tendering processes
- Industry publications, publicly available data, recognised reputable commercially available software package and vendor information
- CCS costs were obtained using a recognised reputable commercially available software package

This cost data has been normalised or adjusted to account for differences in battery limits, scope, location factors, technical factors (where relevant), etc.

A representative cost has been selected for the hypothetical project from the data available, and cost certainty qualified based on the spread and quality of data available.

Recent trends for each technology have been reviewed and discussed throughout the report. These have been considered when selecting the hypothetical project, nominating technical parameters, and developing the cost estimates on a 2024 basis.

## 3.2 Assumptions and basis

### 3.2.1 General

This section defines the basis used for the hypothetical projects and for determining the technical parameters and cost estimates.

### 3.2.2 Power generation / storage facility

Power generation or storage facility equipment and installation scope is based on the assumptions described in the Table 3-1.

Table 3-1 Power generation / storage facility key assumptions

| Item | Detail |
|---|---|
| Site | Greenfield site (clear, flat, no significant cut and fill required, NEM installation, coastal location (within 200 km of coast within metro areas)) |
| Base ambient conditions: | Dry Bulb Temperature: 25 °C<br>Elevation above sea level: 110 metres<br>Relative Humidity: 60% |
| Fuel quality | Gas: Standard pipeline quality natural gas (HHV to LHV ratio of 1.107)<br>Diesel: No.2 diesel fuel<br>Coal: Black coal<br>Biomass: Woodwaste<br>Waste: Municipal solid waste |
| Water quality | Towns water quality (ie potable)<br>Demineralised water produced on site if required |
| Hydrogen quality | 99.99+% v/v in compliance with ISO 14687-2:2014 and SAE J2719.<br>HHV to LHV ratio of 1.183 |
| Grid connection voltage | 220 – 330 kV)[1] |
| Grid connection infrastructure | Step-up transformer included; switchyard / substation excluded |
| Energy Storage | Concentrated solar thermal – 16 hrs thermal energy storage considered<br>Electrolysers / hydrogen power generation (fuel cells / reciprocating engines / turbines) – Hydrogen compression, transport and storage excluded (relative costs provided separately)<br>BESS – 1, 2, 4, 8, 24 and 48 hours energy storage options considered<br>PHES – 10, 24, and 48 hours energy storage options considered |
| Project delivery | EPC turn-key basis |
| O&M approach | Thermal/hydrogen power generation: Owner operates and maintains, but contracts for scheduled maintenance<br>Renewables or storage: Owner appoints a third-party O&M provider |

The assumed terminal points for the power generation or storage facility are described in Table 3-2. Communication links are considered to be common across technologies and have not been separately defined.

Table 3-2 Power generation / storage facility terminal points

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

[1] It is noted that 500 kV networks are being expanded or implemented to support renewable energy zones and major projects and that large scale generation and storage will connect to these networks over time.

| No. | Terminal point | Terminal point location and details |
|---|---|---|
| 6 | Hydrogen supply (if relevant) | Electrolyser: Outlet of package at delivery pressure (ie no additional compression)<br>Fuel cell: 10 bar supply pipeline at package inlet<br>Reciprocating engine: 10 bar supply at package boundary<br>Turbine (small): 30-40 bar supply at package boundary |

### 3.2.3 Fuel connection / transport

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

The natural gas fuel connection scope assumptions are as follows:

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

The coal fuel connection scope assumptions are as follows:

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

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

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

### 3.2.4 Natural gas compression and storage

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

The natural gas compression scope assumptions are as follows:

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

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

- Storage: Underground storage facility in a depleted natural gas field.

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

### 3.2.5 Hydrogen-based technologies and storage

#### Hydrogen production

Hydrogen is produced by two broad categories of technology: electrolysis, where an electric potential is applied to electrodes in water which then breaks the water into hydrogen and oxygen, and thermal decomposition of hydrocarbons, where heat and pressure is applied to hydrocarbons (eg: natural gas) with steam which causes (ultimately) the breakdown to hydrogen and carbon dioxide. In this report, electrolysis and Steam Methane Reformation (SMR) have been considered.

PEM and alkaline electrolyser technology have been considered. Other electrolyser facility assumptions for the hypothetical project considered in this report and associated costs are included in Section 5.4.4 and Section 5.4.5.

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

#### Electrolyser facility, compression, storage and transport

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

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

Type: Multi-stage reciprocating type

Supply pressure: 30 bar (for PEM) or 1 bar (for Alkaline). Discharge pressure: 100 bar

Capacity (each compressor): 2780 kg/h (3 x 33% duty, for 500MW plant total production rate)

- Scope: Complete supply of compressor(s) and enclosures. Includes civil works. Excluding power supply (assumed co-located with the electrolyser plant).

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

- Type: High pressure steel cylinders (AS 1548 compliant)
- Pressure: 100 bar
- Size: 40ft ISO containers, 350 kg$H_2$ each (at 100 bar)
- Scope: Full supply and installation of storage tanks under D&C contract. Includes civils. Excludes additional compound infrastructure (assumes co-located with a wider facility).

- Other larger storage options may be available depending on storage volume requirements, however, these have not been considered in this report for the purpose of the hypothetical project.

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

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

### Steam methane reforming facility, storage and transport

SMR facility costs are based on information from the International Energy Agency and other sources.

The following points were considered in cost analysis for SMR/CCS:

- Site location: Close to natural gas supply point and consumer location
- SMR plant capacity: Approximately double the current largest in Australia, matching approximately the capacity of several large international plants
- Fuel quality: Australian Standards compliant natural gas
- Water quality: Raw water quality (typical of potable water)
- Hydrogen quality: 99.99% (refer to Table 3-1).

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

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

The costs for hydrogen storage are based upon either a liquefaction and cryogenic storage facility or underground storage. The liquefaction facility is based upon the upper end of a hydrogen liquefaction plants existing today. The largest existing is approximately 32 tpd liquid $H_2$ (Decker 2019). As such a facility of 27 tpd has been selected as a reasonable plant at the upper end of the existing sizes.

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

Costs for a hydrogen pipeline distribution network associated with using hydrogen produced from SMR with CCS are based upon the assumption of a low-pressure distribution network within a city. It will also take some time for a hydrogen network to be installed, so a small network has been sized based upon the assumption of limited hydrogen penetration initially, equivalent to the energy content of 10% of NSW’s natural gas consumption.

- Type: Low pressure distribution within a city
- Capacity: 83.5 tpd
- Pipe materials: HDPE and Steel
- Pressure: 3 Bar (HDPE), 7 Bar (Steel).

### Hydrogen power generation

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

- 25% by volume hydrogen blend with natural gas reciprocating engine plant (current capability of selected OEM for plant size) with a 25% average capacity factor. Performance derate to be confirmed with OEM.
- 35% by volume hydrogen blend with natural gas using a smaller size aeroderivative DLN combustion system gas turbine (current capability) with a 20% average capacity factor. Performance derate to be confirmed with OEM.
- Large gas turbine using 5% hydrogen blend in natural gas supplied from gas network
- Small (0.1 MW) and large scale (1 MW) fuel cell of PEM technology type
- Additional NOx emission control (e.g. SCR) not included if required for hydrogen/gas turbines, potentially required for higher hydrogen blends than currently considered
- Other relevant key assumptions as defined in Table 3-1
- Relevant facility terminal points as defined in Table 3-2

## 3.2.6 Ammonia production facility

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

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

Other assumptions are as included in Section 6.3 and Section 6.4 for hypothetical project and associated cost assumptions.

## 3.2.7 Carbon capture and storage

Carbon capture and storage (CCS) refers to the process of removing the $CO_2$ from the flue gas / exhaust gas which is produced from traditional thermal power stations and typically released into the atmosphere. CCS can also be applied to blue hydrogen production by SMR. The most common form of CCS for power station is a post-combustion capture technology using a chemical absorption process with amines as the chemical solvent.

It has been assumed that in addition to the CCS chemical absorption and $CO_2$ removal and compression process, a coal fired power station with CCS will also require selective catalytic reduction (SCR) for $NO_x$ removal and a flue-gas desulfurization (FGD) plant for $SO_x$ control. In Australia, depending on the coal quality and project location there may not be a specific requirement for the inclusion of SCR or FGD with a new coal-fired power station and as such these are not included in the non-CCS plant configuration. The post-combustion carbon capture absorption process typically has low $NO_x$ and $SO_x$ tolerances however and so these are included in the CCS plant configurations for coal-fired power station.

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

The downstream terminal point for the carbon capture process is assumed to be the outlet of the $CO_2$ compression plant at nominally 150 bar (no temporary storage assumed on site).

$CO_2$ transport costs are provided separately based on onshore transport via underground pipeline from the power station to the storage location. Costs are provided on a $/t$CO_2$/km basis.

$CO_2$ storage costs are provided separately and assumed to involve injecting the $CO_2$ into a depleted natural gas reservoir. Costs are provided on a $/t$CO_2$ basis.

$CO_2$ capture rates of 90% and 50% have been considered.

### 3.2.8 Development and land costs

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

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

The costs for project and land procurement are highly variable and project specific. For the purposes of this report, and outlining development and land costs for a general project within each technology category, a simplified approach must be taken. Land and development costs are calculated as a percentage of capital equipment, and as a result, absolute values associated with these costs will change for those technologies whose equipment capital costs have changed. These costs do not include any applicable fees, such as fees paid to councils, local authorities, electrical connection fee etc. An indicative estimate has been determined based on a percentage of CAPEX estimate for each technology from recent projects, and experience with development processes.

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

### 3.2.9 Financial assumptions

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

- Prices in AUD, July 2024 basis for financial close in July 2024. The Contractor’s prices are fixed at this point for the execution of the project which may take several months or years depending upon the technology
- New plant (no second-hand or refurbished equipment assumed)
- Competitive tender process for the plant and equipment
- Taxes and import / custom duties excluded
- No interest during construction considered
- Assumes foreign exchange rates of 0.65 AUD: USD and 0.60 AUD: EUR
- Assumed fuel costs as below
  - Coal - $3/GJ
  - Gas - $15/GJ
  - Light diesel oil - $41.5/GJ
- No contingency applied
- No development premium considered.

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

- Project location
- Site complexity
- Cost of labour
- Cost of materials

- Market conditions
- Exchange rates.

Where there are no project data or published cost trend available as applicable in the NEM region of Australia since the publication of Aurecon's 2023 report, we have escalated cost data from 2023 report by applying aa cost escalation rate (nominally 5-7.5%, with the exception of GT technologies where an escalation of 10% has been applied due to market conditions and supply chain issues. This escalation rate considers supply chain issues along with increased labour costs observed currently in the construction sector in Australia.

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

The accuracy / certainty of the cost estimates is targeted at +/- 30% based on the spread and quality of data available and our experience with the impact of the above factors.

We did not attempt to undertake any statistical analysis of available data, rather an accuracy band was used. Cost of recent projects and publicly available information was used to arrive at this accuracy band. We did not obtain prices from the market to analyse such data. However, the accuracy band is used to arrive at the cost of a project for certain size, scope of the project, year of completion, level of definition, and its battery limits. Costs vary due to several factors and for this reason this accuracy band is used. For the hypothetical project the cost falls within this target accuracy band.

### 3.2.10 Market volatility and construction cost uncertainties

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

For the purposes of this estimate, we have factored in these considerations and market intelligence of specific industries, plant, and equipment wherever possible to derive a reasonable escalation amount from the 2023 costs.

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

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

Construction cost growth adds a further element of uncertainty to new construction projects and maintenance activities, as well as inflationary pressures to the economy. With construction costs up more than 25% over the past five years, project proponents need to factor in considerable contingencies in addition to prices stated in this 2024 report to allow for uncertainty and movement in construction costs, as well as for operating costs over the life of the project.

## 3.3 Definitions

The following table provides definitions for each of the key terms used throughout this document and in the Excel-based dataset.

**Table 3-3 Definition of key terms**

| Term | Definition |
|---|---|
| Summer rating conditions | DBT: 35°C |
| Base / design conditions | DBT: 25°C, RH: 60%, 110 m elevation |
| Not summer rating conditions | DBT: 15°C |
| Economic life (design life) | Typical design life of major components. |
| Technical life (operational life) | Typical elapsed time between first commercial operation and decommissioning for that technology (mid-life refurbishment typically required to achieve this Technical Life). |
| Development time | Time to undertake feasibility studies, procurement, and contract negotiations, obtain permits and approvals (DA, EIA), secure land agreements, fuel supply and offtake agreements, secure grid connection, and obtain financing. This period lasts up until financial close. |
| EPC total programme | Total time from granting of Notice to Proceed (NTP) to the EPC Contractor until Commercial Operation Date (COD). |
| Total lead time | Time from issue of NTP to the EPC contractor up to the delivery of all major equipment to site. |
| Construction time | Time from receipt of major equipment to site up to the commercial operation date (COD).<br>*Note that for simplicity it has been assumed that the total EPC programme = lead time + construction time. In reality lead time and construction time will overlap which would result in a shorter actual construction time to that stated.* |
| Minimum stable generation | The minimum load - *as a percentage of the rated gross capacity of that unit* - that the generator unit can operate at in a stable manner for an extended period without supplementary fuel oil or similar support, and reliably ramp-up to full load while continuing to comply with its emissions licences. |
| Gross output | Electrical output as measured at the generator terminals. |
| Auxiliary load | The percentage of rated generation output of each unit - *as measured at the generator terminals* - that is consumed by the station and not available for export to the grid. This includes cable and transformer losses. The auxiliary load is provided as a percentage of the rated output at full load. |
| Net output | Electrical output exported to the grid as measured at the HV side of the generator step-up transformer.<br>The net output of the unit can be calculated as the rated gross output at the generator terminals minus the auxiliary load. |
| Planned maintenance | Where a unit or number of units are offline for schedule maintenance in accordance with the OEM recommendations. |
| Average planned maintenance downtime | The average annual number of days per year over the Design Life that the power station (or part thereof) is offline for planned maintenance and unavailable to provide electricity generation.<br>For configurations with multiple units the downtime - *in number of days per year* - has been proportioned in relation to the units' contribution to the overall power station capacity. |
| Forced maintenance / outage | Full and partial forced outage represent the percent of time within a year the plant is unavailable due to circumstances other than a planned maintenance event.<br>In principle, "forced outages" represent the risk that a unit's capacity will be affected by limitations beyond a generator's control. An outage - *including full outage, partial outage, or a failed start* - is considered "forced" if the outage cannot reasonably be delayed beyond 48 hours. |
| Equivalent forced outage rate (EFOR) | Equivalent forced outage rate is the sum of all full and partial forced outages/de-ratings by magnitude and duration (MWh) expressed as a percentage of the total possible full load generation (MWh).<br>*Note Specific formulas are as defined in IEEE Std. 762.* |
| Ramp up/down rate | The rate that an online generating unit can increase or decrease its generation output without affecting the stability of the unit ie while maintaining acceptable frequency and voltage control. |

| Term | Definition |
|---|---|
| Heat rate | The ratio of thermal energy consumed in fuel over the electrical energy generated. |
| Efficiency | Calculated using: Efficiency (%) = 3600 / Heat Rate (kJ/kWh) x 100 |
| Battery storage: Charge efficiency | The efficiency of the battery energy storage system (in %) when the battery is being charged. |
| Battery storage: Discharge efficiency | The efficiency of the battery energy storage system (in %) when the battery is being discharged. |
| Battery storage: Allowable maximum state of charge (%) | The maximum charge % of the battery system. |
| Battery storage: Allowable minimum state of charge (%) | The minimum charge % of the battery system. |
| Battery storage: Maximum number of cycles | The maximum total number of cycles within a typical battery lifetime. |
| Battery storage: Depth of discharge (DoD) | The percentage to which the battery can be discharged – ie the difference between the maximum allowable charge and minimum allowance charge states. |
| Total EPC cost | The EPC contract sum (exclusive of taxes). |
| Equipment cost | The component of the EPC contract sum that is primarily attributed to the supply of the major equipment.<br>*Note that the total EPC cost has been split into "equipment cost" and "installation cost" for the purpose of this study, based on a typical proportion for that technology. Other EPC cost factors such as engineering, overhead, risk, profit, etc have been distributed evenly between the two.* |
| Installation cost | The component of the EPC contract sum that is primarily attributed to the site construction, installation, and commissioning works.<br>*Note that the total EPC cost has been split into "equipment cost" and "installation cost" for the purpose of this study, based on a typical proportion for that technology. Other EPC cost factors such as engineering, overhead, risk, profit, etc have been distributed evenly between the two.* |
| Carbon capture cost | The component of the EPC contract sum that is primarily attributed to the supply, construction, installation, and commissioning works for the carbon capture equipment and associated components. |
| Fixed operating cost ($/MW Net/year) | Fixed costs include; plant O&M staff, insurance, minor contract work, and miscellaneous fixed charges such as service contracts, overheads, and licences.<br>For some technologies where operation and maintenance are holistically covered by O&M and/or Long Term Maintenance Agreement (LTMA) type contracts, all of the operating costs have been classed as "fixed" for the purposes of this study. |
| Variable operating cost ($/MWh Net) | Variable costs include; spare parts, scheduled maintenance, and consumables (chemicals and oils).<br>Variable costs exclude fuel consumption costs. |
| Total annual O&M Cost | Annual average O&M cost over the design life. |
| Energy consumption | Energy required to compress per tonne of hydrogen or to produce per tonne of ammonia (MWh/tonne) |
| Hydrogen consumption | Based on ammonia synthesis consumption, kg of hydrogen required per tonne of ammonia production, kg ($H_2$)/t$NH_3$ |
| Water consumption | Water required to produce per tonne of ammonia, $m^3$/t($NH_3$), or required to produce per kg hydrogen (L/kg$H_2$) |
| Hydrogen production rate | Hydrogen produced per day (kg of $H_2$ per day) for SMR plant, or per hour (kg of $H_2$ per hour) for electrolyser plant |
| Mass liquid $H_2$ stored | Tonnes of liquid $H_2$ storage |
| Annual ammonia output | Ammonia produced per year, tonnes per annum (tpa) |

# 4 Generation Technologies

## 4.1 Overview

The following sections provide the technical and cost parameters for each of the nominated generation technologies (base load, variable generation, firming generation for variable renewable technologies and bioenergy), along with a brief discussion of typical options and recent trends. The information in the respective tables has been used to populate the AEMO GenCost 2024 Excel spreadsheets, which are included in Appendix A.

All auxiliaries up to the HV side of grid voltage step-up transformer are included within the cost and technical parameter review. Refer to Table 3-2 for the terminal points assumed for each generating technology. For the grid connection voltage, the assumption has been made that the majority of large-scale projects will connect to the 220 – 330 kV network (see Table 3-1). It is noted that 500 kV networks are being implemented or expanded to support Renewable Energy Zones (REZ) and major infrastructure projects. Large scale generation and storage will connect to these higher voltage networks over time.

## 4.2 Onshore wind

### 4.2.1 Overview

Wind energy - *along with solar PV* - is one of the leading types of renewable power generation technologies installed, both globally and in Australia. The most common technology used is the three-bladed horizontal-axis wind turbine (HAWT), with the blades located upwind of the tower. These turbines can be designed for a range of wind conditions with some optimised for low wind speed sites (6-7 m/s annual average wind speed) and some for high wind speed sites (>8 m/s annual average wind speed). Grid-connected wind turbines are considered a reliable and mature technology with many years of operational experience. The recent unit upscaling that the industry has experienced was primarily facilitated by higher hub heights and increasing blade lengths. The increase in rotor diameter allows more energy to be extracted from the resource at a given wind speed (compared to a smaller rotor, valid until the rated wind speed is reached), as the amount of energy that can be extracted by a wind turbine is proportional to the swept area of the rotor. For a particular wind turbine platform, larger rotors may also be considered as suitable for unlocking lower wind speed sites. The potential for increased rotor size on a given turbine platform depends on a number of factors including availability from OEMs, mechanical loading limits, and lifetime fatigue loads.

### 4.2.2 Typical options

Previously installed utility-scale wind turbine sizes range from approximately 1 to 6 MW, with recent projects under construction installing 6.2 MW class machines. Depending on unit capacity, hub heights can vary between 50 to 166 m, and rotor diameters from 60 m to 172 m. New models proposed for near future projects are around 7-8 MW in capacity with rotor diameter of up to 195 m in diameter. A present limit on hub height is 166 m, due to current limitations on mobile boom crane lifting capacity and reach.

Onshore wind developments are critically dependent on:

- Access to land
- Planning permissions / development consents
- Environmental approvals
- Nearby grid transmission capacity
- Suitable port infrastructure for import and laydown
- Transport route suitability
- Construction resources and workforce.

The available wind resource, while still important in determining the overall attractiveness of a project, is not as restrictive as it once was. Increases in turbine hub height and rotor diameter, along with design improvements to turbine components, have improved the economic viability of onshore wind projects in certain medium-to-low wind speed regions, which has opened up larger areas for development.

Subject to the above dependencies, modern onshore grid-connected wind farms can range from 20 to over 200 turbines. Various OEMs and turbine models have slightly different power curves, with some more suited to a particular site wind resource than others. As such, net capacity factor and levelised cost of energy (LCOE) are highly site-specific.

A number of projects are also increasingly being delivered with a co-located or geographically proximate battery to reduce intermittency of generation and improve utilisation of the grid connection assets.

### 4.2.3 Recent trends

Wind turbine design has been evolving over the last few decades. Early focus was on very high average wind speed sites to allow for best energy production and overall project economics (annual mean wind speeds of 8.5m/s to 10m/s). In recent years, the hub height of wind turbines has increased dramatically. In addition to allowing access to higher wind speeds at greater heights within the atmospheric boundary layer, a higher hub height also enables longer blade lengths to be considered. This rapid upscaling has led to the development of 7-8 MW class wind turbines, which are currently being proposed at projects across Australia. Alongside increases in capacity, it has also been possible to apply larger rotor diameters on earlier wind turbine platforms, opening up medium (7.5 to 8.5 m/s) and low wind speed (6.5 to 7.5 m/s) sites for economic development. A number of wind turbine manufacturers offer a range of rotor sizes on a given platform, providing both high and low wind speed options for a given drivetrain configuration, reducing complexity and allowing a greater level of shared components between models of a given platform. The wind turbines selected for a given site will be selected according to the Specific Power[2] that best matches the wind speed resource and maximises annual energy production relative to the lifecycle costs.

Turbine power outputs, hub heights and rotor diameters have seen rapid increase over the last decade, however, limiting factors to ongoing increases include lifting capacity and maximum reach of the currently available cranes. Various cost pressures over the last few years, including shipping challenges, increases in costs of labour and key commodities, have led to significant increases in turbine costs and the associated LCOE of wind energy projects. Despite the stabilisation of commodity pricing, and removal of supply chain bottlenecks, these recent cost increases have not reversed. Terrain complexity and wind farm constructability issues are causing additional cost pressures, with bulk earthworks for the required road gradients, hardstand sizing (considering the component delivery, laydown, and crane installation methodology), and geological features such as hard rock creating significant cost overruns in the balance of plant construction costs as the design maturity increases.

Turbine suppliers have reviewed their risk appetite in the booming global market noting profitability challenges over the last few years and appear to be taking the opportunity to reset turbine pricing to a more sustainable level. A number of projects under development are negotiating on split scope contracts (with separate wind turbine supply and install contract and balance of plant contract), whereas previously wind turbine manufacturers had been taking on the role of principal contractor under an Engineer, Procure and Construct (EPC) contract. While split scope contracting structures could unlock cost savings through the removal of the risk premium paid to an EPC contractor, a prudent developer would maintain a contingency budget reflecting a total project cost at a level commensurate with previous EPC pricing. If the contingency is not spent, then the budget will remain with the developer, rather than going to the EPC contractor as a risk premium.

For projects that are currently planned and under construction, wind turbine sizes in the 4.5 – 7.2 MW range are being used. This is consistent with global trends, where wind turbines of 4 MW and greater make up almost 79% of the installed capacity in 2023[3] (with 40% of 2023 global deployment being turbines of 5 MW and above).

[2] A wind turbine's specific power is the ratio of nameplate generation capacity (watts) to rotor swept area ($m^2$)
[3] Global Wind Market Development - Supply Side Data 2023, Global Wind Energy Council

Some of the latest early-stage development projects in Australia are considering wind turbines in the range of 7-8 MW, with these models currently under development by the leading wind turbine manufacturers and being actively marketed. However, further upscaling in onshore wind turbine capacity is not expected beyond these levels in the short term. Recent market events have shown the downside risk of the rapid upscaling experienced in the wind energy sector. Multiple turbine suppliers have faced significant component failures and warranty related claims in recent months, and the cost of rectification works may challenge the supplier's profitability for wind farms utilising the affected turbine models. The market may see a consolidation of turbine models and establishment of a longer track record building phase prior to large technology innovation cycles.

An additional market trend is the rise of non-European wind turbine suppliers exploring international growth opportunities. Typically, the pricing of such turbines is highly competitive, and more so with the recent price increases from the European manufacturers. Although largely having been confined to their domestic market, a number of non-European wind turbine suppliers are looking at Australian and international markets for future growth, challenging the established leading position that European turbine suppliers have enjoyed to date. Downward pressure on wind turbine pricing may come from increasing market share from non-European wind turbine suppliers.

Wind farm sizes throughout Australia have varied, with the largest (Golden Plains Wind Farm - East) being 756 MW in capacity, but the majority of developments being below 300 MW in capacity. However, in recent years new wind farms - *planned and under construction* - are expanding to total capacities in the range of 300 to 1,500 MW (and in some cases beyond).

Typical capacity factors at the point of connection range from 30% to 40%. Capacity factors are linked to the wind resource and turbine model used and therefore vary significantly from project to project. The main turbine-specific factor influencing capacity factor is the size of the rotor relative to the rated power output of the generator (ie, the Specific Power). The spacing of turbines within the available land also influences capacity factor due to internal wind farm wake losses that will vary depending on the turbine spacing, with tighter spacing resulting in increased wake losses.

In general, the economic viability of a wind farm design is driven by capital costs, ongoing maintenance expenditure, the energy production and local energy market conditions and incentives. The Australian market has no direct incentive for achieving highest capacity factor, and therefore projects are driven by optimising the overall Levelised Cost of Energy (LCOE), which typically favours larger machines (economies of scale in CAPEX and OPEX costs, and, with appropriate wind resource, larger specific annual energy production) even at the expense of reduced capacity factor.

Between 2010 and 2021 there was a rising trend in capacity factor across many international wind markets for newly installed projects[4]; the average capacity factor for new wind farms has reduced slightly to 36% from the peak of 39% in 2021. Australia has remained largely consistent in average capacity factor in recent years. While there are several underlying reasons why this may be the case, three clear trends are the development of wind farms in low-to-medium wind speed sites (as better resource locations have already been developed, and some excellent resource at the fringes of the electricity network remain challenging to develop and connect); Secondly, Australia has rapidly upscaled in technology to 6 MW class machines, whereas other geographic regions (such as North and South America) typically utilise wind turbines in the 3-4 MW class. Higher hub heights access higher wind speeds, and allow for increased rotor sizes, but the smaller unit rating coupled with a larger rotor diameter allows for higher capacity factors to be achieved. Thirdly, there is a tendency within wind energy projects developed in Australia to target a technical life (operational life) of 30 years or more. The economic life (design life) of a wind turbine is typically 20-25 years, as denoted on a specific model's type certificate. Operating a wind turbine in a wind climate that is less energetic than the design conditions allow for theoretical life extension, and this 30-year term is now taken as an expectancy rather than the exception. As a result of this extended operational life, operating wind turbines in a wind climate less energetic than the design conditions is a necessity, and capacity factor reduction is one of the direct consequences. The lower capacity factor of Australian projects should not necessarily be seen as a negative, as project economics will likely have favoured the selection of larger capacity machines with a longer operational life, despite the reduced capacity factor.

[4] IRENA. (2024). Renewable Power Generation Cost in 2023. Abu Dhabi: International Renewable Energy Agency.

The development of new windfarm projects has become more challenging in part due to prudent environmental considerations and the requirement for offsetting for any vegetation clearance that may be required for the construction of wind farm assets. More stringent grid connection requirements also necessitate increased modelling associated with the Generator Performance Standards, and system strength remediation identified during Transmission Network Service Provider and AEMO modelling may stipulate that additional supporting infrastructure (such as synchronous condenser or grid-forming BESS) be included as a project enabler, at the cost of the developer. Cost increases and schedule delays have been seen across a range of projects to allow for completion of the supporting studies, with more certainty required by investors and lenders prior to starting construction. These factors have been extending the overall development timeframes for new wind farms in Australia.

Design life of an onshore wind farm is typically 25 years based on the certified design life of the turbines. However, in recent years investors have assumed economic life of 30 or 35 years, with an associated increase in maintenance costs in later years to address increasing numbers of component failures. It is important that structural components such as towers, foundations, blades, hub, main bearings, and nacelle bed frame can operate for this extended period, and this is typically investigated and verified through robust mechanical loads assessments and site-specific assessments of the turbine loads placed on the specific turbine model over the project timeframe and the anticipated wind resource at a given project location.

Within the wind turbine electrical system, a larger proportion of wind turbines are now utilising full scale power converters (previously the majority of onshore wind turbines used doubly fed induction generators). While higher in cost, these full-scale power converters can be optimised for improved power system performance and are scalable to higher power outputs.

A recent innovation that is being applied within variable renewable energy generation such as wind turbines is inverter level voltage control. Fast-acting local inverter level voltage control can be a mechanism to achieve increased stability of the power system whilst retaining existing current-source (grid following) inverter topologies. Typically, voltage control is applied at a wind power plant level through the power plant controller. Wind turbine inverter level voltage control could be a step change in technology performance reducing the time lag between signal measurement and system response, enhancing grid stability in low inertia grid networks or weak areas of the network.

An increased focus on platform and component modularity is taking place across the industry to achieve improvements in logistics and transportation. This includes modular nacelle assemblies, and hybrid concrete and steel towers, aimed at reducing the costs associated with development approvals, permits and road upgrade and augmentation work required for transport of large turbine components.

### 4.2.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project upon which costing is based. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024, given the above discussion on typical options and current trends.

**Table 4-1 Configuration and performance**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology / OEM | | Vestas | Other options include GE, Goldwind, Nordex, Siemens Gamesa. |
| Make model | | V162-6.2 | Based on current new installations |
| Unit size (nominal) | MW | 6.2 | ISO / nameplate rating |
| Number of units | | 100 | |
| **Performance** | | | |
| Total plant size (Gross) | MW | 620 | |
| Auxiliary power consumption and losses | - | 3% | No significant auxiliary power consumption during wind farm operation but there are electrical distribution losses from the turbines to the substation. |

| Item | Unit | Value | Comment |
|---|---|---|---|
| Total plant size (Net) | MW | 601.4 | |
| Seasonal rating – Summer (Net) | MW | 601.4 | Derating occurs above 20°C at hub height (altitude dependent) based on OEM datasheet. Note derating only occurs in high generation (ie, high wind speed) and high temperatures, which generally have a very low probability of simultaneous occurrence. |
| Seasonal rating – Not Summer (Net) | MW | 601.4 | Accounting for temperature related factors only. |
| **Annual Performance** | | | |
| Average planned maintenance | Days / year | - | Included in EFOR below. |
| Equivalent forced outage rate | - | 2.5% | Majority large wind farms currently being constructed in Australia have contractual warranted availability of up to 97.5% for wind turbines for up to a 20-year period. Availability guarantees can extend further, but the contractual availability value typically drops off after year 20. |
| Effective annual capacity factor (P50, year 0) | - | 36%[5] | Value taken from the IRENA global weighted average capacity factor for newly commissioned wind farms. Net capacity factor will be site-specific. Dependent on wake losses, wind resource, and electrical losses. Based on gross capacity. |
| Annual generation | MWh | 1,850,000 | Provided for reference. |
| Annual degradation over design life | - | 0.1% pa | Assuming straight line degradation, ie, proportion of initial energy production. |

**Table 4-2 Technical parameters and project timeline**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Technical parameters** | | | |
| Ramp up rate | MW/min | Resource dependent | |
| Ramp down rate | MW/min | Resource dependent | Full ramp down of wind farm on command <30s if required by the Network Service Provider in a contingency event. |
| Start-up time | Min | N/A | Always on. < 5 min after maintenance shutdown. |
| Min stable generation | % of installed capacity | Near 0 | |
| **Project timeline** | | | |
| Time for development | Years | 3 – 5 | Includes pre-feasibility, design, approvals etc.<br>For wind, a key factor is the availability of wind resource data. Installing wind masts at the nominated hub height can add 12 months to detailed feasibility assessments, pushing the timeframe to the upper end of the scale. Obtaining development approvals and consents can also add considerable time to the overall development schedule.<br>Conversely, if there are already long-term consents in place development time could be in the order of 2 years. |
| First year assumed commercially viable for construction | Year | 2024 | |

[5] IRENA. (2024). Renewable Power Generation Costs in 2023. Abu Dhabi: International Renewable Energy Agency.

| Item | Unit | Value | Comment |
|---|---|---|---|
| EPC programme | Years | 3 | For NTP to COD. |
| ▪ Total lead time | Years | 1 | Time from NTP to first turbine delivered to site. |
| ▪ Construction time | Weeks | 90 | Time from first wind turbine erection to Wind Farm Practical Completion. |
| Economic life (design life) | Years | 20 – 25 | Varies between manufactures. Typically shown on the WTG model Type Certificate. |
| Technical life (operational life) | Years | 30 – 35 | Includes site specific assessment and life extension but not repowering. |

### 4.2.5 Cost estimates

**Table 4-3 Cost estimates**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX Construction** | | | |
| Relative cost | $ / kW | 3,050 | Based on Aurecon internal benchmarks. Relative cost does not include land and development costs. |
| Total cost | $ | 1,891,000,000 | |
| ▪ Equipment cost | $ | 1,418,250,000 | 75% of EPC cost – typical. |
| ▪ Installation cost | $ | 472,750,000 | 25% of EPC cost – typical. |
| **Other costs** | | | |
| Cost of land and development | $ | 47,275,000 | Assuming 2.5% of CAPEX. Note land for wind farms is typically leased. |
| Fuel connection costs | $ | N/A | |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / MW (Net) | 28,000 | Average annual cost over the design life. O&M costs typically increase incrementally over the project life. |
| Variable O&M Cost | $ / MWh (Net) | - | Included in the fixed component. |
| Total annual O&M Cost | $ | 17,360,000 | Annual average cost over the design life. |

## 4.3 Offshore wind

### 4.3.1 Overview

The global offshore wind sector has undergone rapid expansion in recent years with major advances in technology and cost reductions, making offshore wind an increasingly competitive option for large scale energy generation. The offshore wind industry in Australia is still very much in its infancy, however it is being backed with significant state and federal support and is garnering huge attention from experienced international developers.

Offshore wind developments can offer some advantages over onshore projects:

- Access to offshore wind resources which when compared to onshore resources are generally:
  - stronger
  - less turbulent
  - complimentary diurnal profiles to other variable renewable generation technologies (ie, windier in the late afternoon and evening than onshore and complimentary to Solar PV)
- Reduced visual and noise pollution concerns, due to being out at sea

- An offshore development adjacent to a large demand centre (city) can avoid expensive overland transmission compared to some onshore projects,
- which are often located far from demand centres where there is available space for development
- Typically, larger space for development offshore than onshore
- Turbines are typically manufactured near canals or ports and barged directly to the marshalling port, which avoids the need for road and bridge upgrades, noting that significant port upgrades are required at marshalling ports.

A combination of the above factors permits the use of much larger and a greater number of wind turbines offshore which can improve project economics. Offshore wind turbines typically have hub heights in excess of 150m and differ from onshore wind turbines with the implementation of longer, more efficient, and durable blades. At the upper end of the scale, currently deployed turbines featuring taller towers and longer blades enable rotor sizes of up to 260m, with a swept area of up to 50,000m². Offshore wind turbines differ from onshore wind turbines due to the fact that they are designed to survive in the aggressive offshore environment and involve very different foundations.

Commonly cited challenges include:

- Complex projects that are difficult and expensive to build
- Proximity to onshore transmission infrastructure and associated costs
- Harsh conditions from marine operating environment
- Specialist vessel availability for construction and installation
- Expensive operation and maintenance costs of offshore sites.

The Offshore Wind industry is facing many challenges today, such as inflation, increased capital cost and supply chain constraints. This has created uncertainty and forced developers to review the viability of their projects and, in some cases, to even terminate their offtake contracts and stop developing projects expected to be built in the next five years. Major western OEMs in this sector have faced a profitability crunch over the last few years, causing them to retrench and selectively withdraw from smaller or slower-moving markets and amid these problems, they are raising their prices. These challenges will be particularly relevant to Australia, given its current nascent offshore wind market.

For the purpose of this report, we have considered international average costs without considering any regional uplift of costs that would be expected for the deployment of an offshore wind farm in Australian waters. Given the uncertainties surrounding turbine unit capacity (and associated component size), vessel and lifting equipment availability, workforce availability, the requirements for a particular level of local content, and the fact that there is no present experience in the installation of offshore wind, there are too many unknowns to accurately characterise a regional pricing uplift, therefore international cost averages from recognised intergovernmental agencies have been drawn upon for the purposes of this report.

### 4.3.2 Typical options

Existing offshore wind turbines range in nameplate capacity from 3 MW to 16 MW. In 2023 the European average output capacity of newly installed offshore turbines was approximately 9.7 MW, up from 8MW in 2022. Based on disclosed wind turbine orders the average power rating of offshore turbines ordered reached 14.9MW (12.2 MW in 2022)[6]. Aurecon notes however, that the market is trending towards even larger turbines due to their synergies (see Section 4.3.1 above). It is noted that some original equipment manufacturers (OEMs), such as Vestas, and other industry experts have expressed reservations about further increasing turbine size. They believe that prioritizing supply chain and research and development investments, along with the benefits of standardization and industry learning, can ultimately lower costs and drive the industry forward. This hesitation became evident when General Electric abandoned plans for an 18-MW turbine and instead opted for a smaller 15.5-MW model[7]. Many offshore wind projects under

[6] Europe, W. (2023). Wind Energy in Europe 2023 Statistics and the outlook for 2024-2030. Brussels: Windeurope.
[7] NREL (2024), Offshore Wind Market Report

construction or in operation commonly have between 50-175 turbines and 400 MW+ capacity. Aurecon notes that globally there are multiple projects in the development pipeline with capacities in excess of 1,000 MW.

Most large-scale offshore wind farms in operation are fixed foundation, with an upper depth limit of approximately 50 - 60m, noting that:

- Traditionally mounted wind turbines use a single monopile in water depths <30 m
- Tripod, tri-pile or jacket structures are typically selected for depths of up to ~60 m due to economical and practical reasons, noting that to date the deepest fixed foundation installed is located at the Seagreen project where a jacket foundation was installed to a depth of 58.6 m.

For depths over 60 m, floating foundation concepts are more economically viable than bottom-fixed foundations, which consist of a floating structure that provides buoyancy to support the entire WT and stabilize the structure's motion, along with a mooring system that employs anchors to secure the foundation to the seabed. There are four major categories of floating foundations including spar, barge tension-leg platform (TLP) and semi-submersible platform. By far, the industry does not have a clear consensus on preferences, and state of art suggests that a case-by-case selection is being done depending on factors such as depth and the type of seabed.

Although the floating offshore wind has not been largely commercially operated as of 2023, a number of pilot projects have been installed at sea sites or in their planning stage. The first commercially operating wind farm using floating type foundation, Hywind Scotland, was commissioned in late 2017 and has been followed by a number of demonstration projects since, with net installations reaching ~200 MW in 2022 and expected to be bolstered with a further 300 MW deployed in France and China during 2023. Floating foundation offshore wind farms are still considered to be in the early commercialisation stage with a number of projects under development. As a result, they are expected to undergo significant cost reductions as the technology matures over the following decade.

### 4.3.3 Recent trends

While the cost of offshore wind has been falling dramatically since 2015, from about 5,900 USD / kW down to 3,137 USD / kW in 2021, 2022 saw a slight increase at 3,478 USD / kW before decreasing to 2800/kW in 2023[8]. The overall reduction in cost from 2015 to 2021 can be credited to the increase in deployment, technology improvements, economies of scale, and increases in turbine developer and manufacturer experience. However, the yearly volatility from 2021 to 2022 causing an increase in costs can be attributed to several things, such as global supply chain shortages caused by the impact of Covid 19, commodity price inflation caused by the ongoing war in Ukraine which impacted vessel charter costs due to the inflated price of bulk diesel and the distribution in offshore wind installation across regional markets. In 2023, the global cumulative installed capacity of offshore wind increased by 11 GW (17%), year-on-year, of which 7 GW was added in China and 3 GW in Europe. China accounted for 58% of global deployment in 2022[9] rise to 64% in 2023[8]. The level of Chinese market dominance since 2021 heavily influences the global weighted average installed costs as China benefits from lower commodity prices and labour costs, as well as the near shore and inter-tidal nature of most Chinese wind farms. China has historically subsidised the transmission costs associated with offshore wind projects, although going forward these subsidies will no longer be available to developers.

It should be noted that these cost reductions have been realised off the back of a maturing European and rapidly expanding Chinese development and delivery market. Given that the current offshore development and delivery capability in Australia is virtually non-existent, costs for offshore wind in Australia are expected to be above the international average until experience is gained and supply chains established. Aurecon would recommend caution in assuming efficient translation of these global costs to Australian projects. If costs are applied for Australian projects, developers will need to factor in costs of shipping turbines and specialist installation equipment (for example, jack up vessels). For the purpose of this report, we have considered international average costs without considering any regional assumptive uplift of costs.

The international cost benchmarks are not entirely consistent regarding grid connection costs as these are not paid for by developers in every country. As noted in Table 4-6, connection costs are broadly expected to

[8] IRENA (2024), Renewable power generation costs in 2023, International Renewable Energy Agency, Abu Dhabi.
[9] GWEC. (2023). Global Offshore Wind Report 2023.

be in the range of 8-24% of total construction costs[8]. There is limited data currently available in Australia regarding connection costs for offshore wind projects, but Aurecon expects that subsea cables for GW-scale offshore projects may cost around AUD20M/km compared to around AUD10M/km for onshore cable, assuming a voltage of 220 kV (we expect that all onshore connection routes will need to be underground cable rather than overhead transmission line). If a typical fixed-foundation offshore wind farm is 30 km from shore and has 20 km onshore to reach the grid connection point, cable and overhead line costs alone would be circa AUD800M. Other connection costs of AUD100M could be incurred depending on the connection point and configuration, suggesting circa AUD900M total connection costs (offshore substation is assumed to be part of the wind farm rather than a connection cost). For the hypothetical 1200 MW project described in the following section with total cost of circa AUD5.2B, connection cost of AUD900M would represent around 17.5% of total cost which is broadly consistent with the guidance provided from international benchmarks (between 8% and 24%). In addition, some studies of offshore wind in Australia indicate the total grid connection cost (substations and cables) in some offshore regions adjacent to existing large transmission networks could be lower than 1000A$/kW[10].

Grid connection cost for floating offshore wind will be greater as they tend to be located further form shore. These costs relative to their total construction cost are not yet known due to their lack of deployment. It is currently unclear whether offshore wind developers will pay for connection costs, noting that recent announcements by the Victorian Government indicate that the entity VicGrid will fund and build connection infrastructure for offshore wind farms in the state. The approach in other states has yet to be finalised.

### 4.3.4 Selected hypothetical fixed foundation project

The following tables outline the technical parameters for the hypothetical fixed foundation project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2023 (if a project was suitably advanced to start construction) given the above discussion on typical options and current trends. The technical parameters as well as typical project timelines of fixed foundation wind farm are outlined in Table 4-4 and Table 4-5.

**Table 4-4 Fixed foundation configuration and performance**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology / OEM | | GE | Other options include Vestas, Goldwind, Siemens Gamesa, etc. |
| Make model | | Haliade-X 12 MW | |
| Unit size (nominal) | MW | 12 | Although the average power rating of European offshore wind turbine ordered in 2023 was 14.9 MW, 12 MW is used in this report considering Australia market is still in its early stage and lacks of project experience |
| Number of units | | 100 | Typical for offshore wind farms |
| Site Condition | m / km | Site water depth: 30m<br>Distance to the shoreline/grid/port: 50km | Bottom-fixed structure by using monopile foundation |
| **Performance** | | | |
| Total plant size (Gross) | MW | 1200 | |
| Auxiliary power consumption | % | 4% | No significant auxiliary power consumption during wind farm operation but there are electrical distribution losses from the turbines to the substation.<br>Nominal allowance only. Dependent on distance from shore. |

[10] Gao, Qiang, et al. "Detailed mapping of technical capacities and economics potential of offshore wind energy: A case study in South-eastern Australia." Renewable and Sustainable Energy Reviews 189 (2024): 113872.

| Item | Unit | Value | Comment |
|---|---|---|---|
| Total plant size (Net) | MW | 1152 | |
| Seasonal Rating – Summer (Net) | MW | 1152 | Derating occurs above 35°C based on OEM datasheet. Note derating only occurs in high generation (ie high wind) and high temperatures. |
| Seasonal Rating – Not Summer (Net) | MW | 1152 | |
| **Annual Performance** | | | |
| Average Planned Maintenance | Days / yr. | - | Included in EFOR below. |
| Equivalent forced outage rate | % | 5% | Based on international benchmarks. |
| Effective annual capacity factor | % | 49% | Anticipated capacity factors for the new offshore wind farms built in Europe in 2023 ranges between 42% and 55%[6]. |
| Annual generation | MWh / yr. | 5,150,880 | Provided for reference and based on total plant size (gross) operating at the effective annual capacity factor. |
| Annual degradation over design life | % | 0.1% | Assuming straight line degradation. |

**Table 4-5 Technical parameters and project timeline**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Technical parameters** | | | |
| Ramp up rate | MW/min | Resource dependent | |
| Ramp down rate | MW/min | Resource dependent | |
| Start-up time | Min | N/A | Always on. < 5 min after maintenance shutdown. |
| Min stable generation | % of installed capacity | Near 0 | |
| **Project timeline (Reference Figure 4-1)** | | | |
| Time for development | Years | >7 years | Estimation based on the Feasibility Licence duration (7 years based on OEI ACC 2021) |
| First year assumed commercially viable for construction | Year | 2024 | |
| EPC programme | Years | 6 | For MOU, through NTP to COD. |
| ▪ Total lead time | Years | 3 | Time from MOU to first turbine on site |
| ▪ Construction time | Years | 3 | Time from construction commencement to last turbine commissioned.<br>Time from construction commencement to the last turbine commissioned. Based on the IRENA database, the installation time of projects now routinely exceeds 400 MW per year. |
| Economic life (design life) | Years | 25 | |
| Technical life (operational life) | Years | 30 | |

### 4.3.5 Cost estimate – fixed foundation

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 4-6 Cost estimates of fixed foundation**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX** | | | |
| Relative cost | $ / kW | 4,306 | Based on US $2,800 / kW which was the 2023 global weighted-average installed costs for offshore wind[8]. As reported by IRENA in its 2023 and 2024 reports, prices have dropped recently post COVID-19 years.<br>Capital cost includes a certain percent of grid connection cost, typically 8-24%. It is country specific, and in some countries (eg, China, Denmark, and the Netherlands) developers are not responsible for electrical interconnection reducing their installed cost and bringing down the global weighted-average cost. Relative cost does not include land, lease, and development.<br>Exchange rate at time of print:<br>1 USD – 1.538 AUD |
| Total CAPEX cost | $ | 5,167,680,000 | |
| ▪ Equipment cost | $ | 3,514,022,000 | Approximately 68% of CAPEX cost – typical[11]. |
| ▪ Installation cost | $ | 1,395,274,000 | Approximately 27% of CAPEX cost – typical. |
| ▪ Development and Project Management | $ | 258,384,000 | Assuming 5% of CAPEX due to large project scale. |
| Fuel connection costs | $ | N/A | |
| **OPEX** | | | |
| Fixed O&M Cost | $ / MW (Net) | 174,573 | Based on 1GW fixed offshore wind farm cost breakdown.<br>This figure is within the range of the 0.022USD$/kWh to 0.030USD$/kWh O&M cost in Europe most recently outlined by IRENA in Europe.<br>. |
| Variable O&M Cost | $ / MWh (Net) | - | It is included in the fixed component by assuming an offshore farm situated within 50 km distance of the shoreline. |
| Annual O&M Cost | $ | 209,487,705 | Annual average cost over the design life |

### 4.3.6 Selected hypothetical floating foundation project

The following tables outline the technical parameters for the hypothetical floating foundation project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2023 and is considered at a scale applicable for a commercial scale floating offshore wind farm (if a project was suitably advanced to start construction) given the above discussion on typical options and current trends. The technical parameters as well as typical project timelines of floating foundation wind farm are outlined in Table 4-7 and Table 4-8.

[11]Wind farm costs – Guide to an offshore wind farm, 2019.

Table 4-7 Configuration and performance

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology / OEM | | GE | |
| Make model | | Haliade-X 12 MW | |
| Unit size (nominal) | MW | 12 | Same assumption as fixed foundation project |
| Number of units | | 36 | Typical for offshore wind farms |
| Site Condition | m / km | Site water depth: 100m<br>Distance to the shoreline/grid/port: 60km | Floating structure by using steel semi-submersible platform |
| **Performance** | | | |
| Total plant size (Gross) | MW | 432 | |
| Auxiliary power consumption | % | 4% | No significant auxiliary power consumption during wind farm operation but there are electrical distribution losses from the turbines to the substation.<br>Nominal allowance only. Dependent on distance from shore. |
| Total plant size (Net) | MW | 415 | |
| Seasonal Rating – Summer (Net) | MW | 415 | Derating occurs above 35°C based on OEM datasheet. Note derating only occurs in high generation (ie high wind) and high temperatures. |
| Seasonal Rating – Not Summer (Net) | MW | 415 | |
| **Annual Performance** | | | |
| Average Planned Maintenance | Days / yr. | - | Included in EFOR below. |
| Equivalent forced outage rate | % | 5% | Based on international benchmarks. |
| Effective annual capacity factor | % | 49% | Anticipated capacity factors for the new offshore wind farms built in Europe in 2023 ranges between 42% and 55%[6]. |
| Annual generation | MWh / yr. | 1,854,317 | Provided for reference and based on total plant size operating at the effective annual capacity factor. |
| Annual degradation over design life | % | 0.1% | Assuming straight line degradation. |

Table 4-8 Technical parameters and project timeline

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Technical parameters** | | | |
| Ramp up rate | MW/min | Resource dependent | |
| Ramp down rate | MW/min | Resource dependent | |
| Start-up time | Min | N/A | Always on. < 5 min after maintenance shutdown. |
| Min stable generation | % of installed capacity | Near 0 | |
| **Project timeline (Reference Figure 4-1)** | | | |

| Item | Unit | Value | Comment |
|---|---|---|---|
| Time for development | Years | >7 years | Estimation based on the Feasibility Licence duration (7 years based on OEI ACC 2021) |
| First year assumed commercially viable for construction | Year | 2024 | |
| EPC programme | Years | 6 | For MOU, through NTP to COD. |
| ▪ Total lead time | Years | 3 | Time from MOU to first turbine on site |
| ▪ Construction time | Years | 3 | Time from construction commencement to last turbine commissioned. |
| Economic life (design life) | Years | 25 | |
| Technical life (operational life) | Years | 30 | |

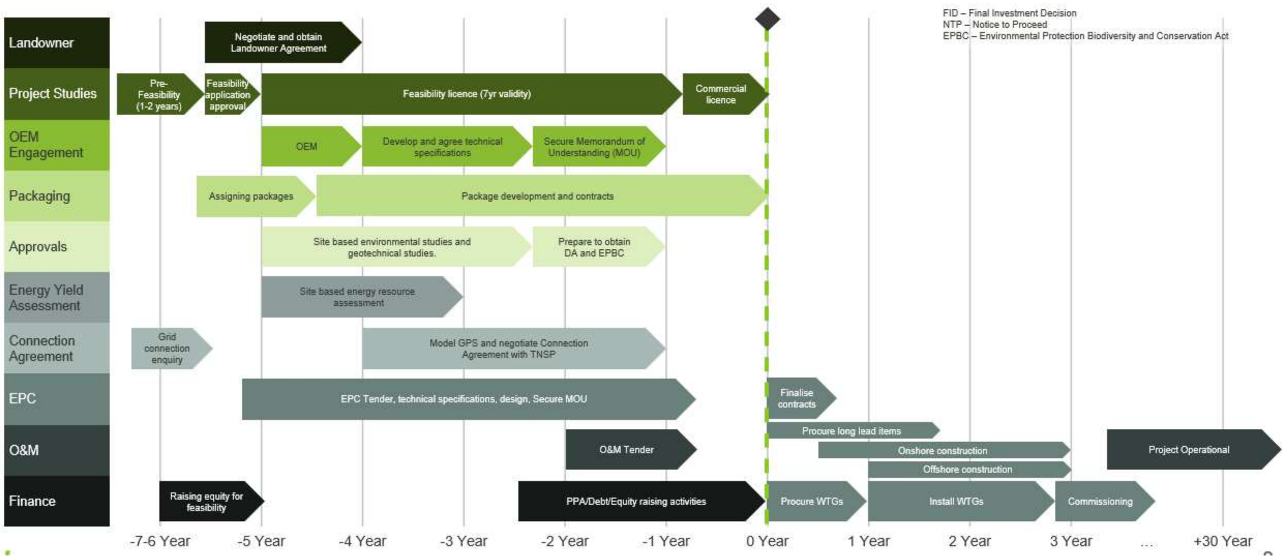


**Figure 4-1 Offshore wind indicative project schedule (applicable for both fixed and floating)**

### 4.3.7 Cost estimate – floating foundation

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 4-9 Cost estimates of floating foundation**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX** | | | |
| Relative cost | $ / kW | 7,724 | There is limited data available due to low deployment of technology especially at commercial scale. Relative costing has derived from the CATAPULT Guide to a Floating Offshore Wind Farm (associated costing spreadsheet) and aligned to consider the hypothetical project outlined in section0. The variation between fixed and floating CAPEX noted is in line with other Offshore Wind costing analysis.<br>Exchange rate at time of print:<br>1 GBP – 1.83 AUD (2021 average) |
| Total CAPEX cost | $ | 3,336,681,600 | Total installed capacity of 432MW |

| Item | Unit | Value | Comment |
|---|---|---|---|
| ▪ Equipment cost | $ | 2,836,179,360 | Approximately 85% of CAPEX cost – typical[12]. |
| ▪ Installation cost | $ | 367,034,976 | Approximately 11% of CAPEX cost – typical. |
| ▪ Development and Project Management | $ | 133,467,264 | Assuming 4% of CAPEX due to large project scale. |
| Fuel connection costs | $ | N/A | |
| **OPEX** | | | |
| Floating O&M Cost | $ / MW (Net) | 247,297 | O&M cost for floating offshore wind is expected to be greater than onshore wind as floating wind farms are located further from the port, exposed to more harsh weather conditions and the immature technology, procedures and efficiencies.<br>As stated, there is limited data available which is very relevant for OPEX. Some publicly available is based on demonstration scale projects which is not representative of a 400 MW wind farm.<br>The figure is taken from a US based study as this was deemed most representative and is in line with other industry values[13]. |
| Variable O&M Cost | $ / MWh (Net) | - | It is included in the fixed component by assuming an offshore farm situated within 50 km distance of the shoreline. |
| Annual O&M Cost | $ | 106,832,278 | Annual average cost over the design life |

Costing associated with floating foundation wind farms is based on today's publicly available information associated with the currently deployed pilot sites. It is anticipated that the OPEX costs associated with maintaining and operating a floating foundation based offshore wind farm will fall in the coming years due to further learning and developments in the market as well as increased scaling of the sites due to be constructed.

The location cost factors provided for other generation technologies are not applicable to Offshore Wind due the variability of projects technical requirements, and thus are not used in this Offshore Wind cost analysis. The locational factors were developed based solely upon onshore energy generation considerations which vary considerably from those affecting offshore. Factors affecting Offshore Wind costs are predominantly site specific such as water depth, distance from shore, distance to the grid and metocean conditions and so cannot be categorized regionally in the same context for onshore generation.

## 4.4 Large-scale solar photovoltaic

### 4.4.1 Overview

Solar PV generation is well established as a significant renewable energy technology both in Australia and abroad. Improvements in solar PV technology and reduction in costs have led to the widespread uptake and increasing sizes of utility-scale solar PV systems.

In large-scale solar PV systems, tens to hundreds of thousands of solar PV modules are connected to inverters, which convert the electricity generated from DC to AC. The outputs from each of the inverters in the solar farm are aggregated and exported to the network through MV/HV transformers as required and then the connection point.

The output of solar PV systems is dependent on the availability of solar resource – varying throughout the day depending on the available sunlight and local weather, as well as varying total resource in different locations. Generally, the solar resource in Australia is excellent, although slightly less in the south and along

[12] Wind farm costs | Guide to a floating offshore wind farm (guidetofloatingoffshorewind.com), 2021
[13] The Cost of Floating Offshore Wind Energy (https://www.nrel.gov/docs/fy21osti/77384.pdf)

the eastern coast. Large-scale solar PV systems are usually located near a major transmission substation to minimise grid connection costs.

### 4.4.2 Typical options

At the utility-scale, solar PV plants typically fall into two categories: fixed-tilt or single-axis tracking. Other configurations such as dual-axis tracking, and floating may be used, but are less common and typically used for niche applications such as smaller installations and short-term deployments. High density ground mount solar farms that utilise minimal spacing between PV strings represent another emerging technology that may see significant uptake in the short to medium term with some very large-scale developments being considered with this technology.

In fixed-tilt systems, modules are mounted on a static frame, which is generally tilted towards the direction of the equator to maximise annual generation ie, in Australia this would typically be north. Some fixed-tilt systems are arranged with half of the panels facing west and half facing east to maximise generation in the morning and evening to better align with daily demand profiles. This configuration can be economically viable where there is an oversupply of generation in the middle of the day.

Most recently constructed utility-scale sites utilise single-axis tracking systems, where modules are mounted on a torque tube which rotates around a north-south axis, allowing the modules to track the sun’s movement from east to west throughout the day. Single-axis tracking systems have a higher capital cost and more maintenance requirements than fixed-tilt systems. However, they generally have a lower LCOE, as they produce more energy throughout the day and align better with higher generation pricing periods – ie increased energy generation over fixed-tilt systems in the early morning and late afternoon.

Solar PV panel (or module) design is another key area which affects overall plant capacity. Historically, mono-facial panels (ie generation on one side of the panel) have been implemented at solar farms. However, bi-facial panels, which also generate electricity on the rear of the panel by capturing reflected irradiance, have become a viable and preferred option. In Australia most new solar farm projects being constructed are using bi-facial panels. N-type modules are now the most common module type used in new utility scale solar farms due to their increased efficiency, reduced degradation and their increasing nameplate capacity.

Due to the relatively low cost of the solar PV modules and the losses associated with the module temperature coefficient and DC system, projects commonly install more solar panel capacity than grid connection capacity (ie higher DC:AC ratio). Simultaneously, projects also install more inverter capacity than grid connection capacity to improve reactive power capabilities and meet connection requirements. Though some power generation may be curtailed in the middle of the day in the early years of the project life, this allows for a more consistent, flatter generation profile. The output of the solar modules typically degrades steadily over the project life, which reduces the level of inverter clipping.

Currently, inverters used for utility-scale sites are typically “central” inverters, rated at 4-10 MW each and supplied on a skid or platform with the MV power transformer, isolation and switching, communications and auxiliary power integrated by the inverter manufacturer.

It is common for solar farms to either be developed alongside a utility scale BESS or to be developed with a future planned BESS installation – see Section 9 for further information.

Many solar farms have experienced delays in the grid connection process. In order to meet power quality restrictions enforced under the Generator Performance Standards, harmonic filters are most often required.

### 4.4.3 Recent trends

Even with concerns about day-time negative pricing events in the NEM, investment in the sector has been stable, with several large-scale solar farms under development in Australia. Solar farm sizes are also on the upward trend with several projects reaching financial close in 2023 and 2024 being in the 200 to 500 $MW_{ac}$ range. This relates primarily to their connection at higher grid voltages and the spreading of fixed project costs across a larger system.

Project design lifetimes are also increasing – where it used to be normal to have a 25-year lifetime, these are commonly increasing to 30-35 years and therefore require more ongoing O&M and replacement costs.

One limiting factor for developers and project owners is the high demand for reputable Engineering, Procurement, and Construction (EPC) contractors over the past year. Aurecon are aware of EPC contractors that are designing and constructing several projects at the same time, and even rejecting projects due to insufficient staffing resources. These challenges have pushed some developers and project owners into investigating other construction models such as multi/split contracts and self-managing.

Central inverter technology has not changed significantly over the last few years, with only incremental improvements to power density and efficiency. However, some newer central inverters offer DC-coupling – where batteries can connect directly to the DC busbar of the inverter alongside the solar PV connections. This allows for a potentially cheaper BESS installation through the usage of common MV equipment, and the ability to further oversize solar DC capacity.

Although still more uncommon, there have also been some utility-scale projects utilising string inverters – smaller inverters with an output power typically ranging between 100-250 kW. This arrangement typically allows for finer monitoring of solar PV strings, reduced mismatch losses, and higher redundancy. Some manufacturers are also offering “modular” inverters which aim to combine the benefits of both central and string inverters. This system consists of multiple ~1MW inverter blocks connected in parallel to increase the overall inverter capacity up to ~9MW on single platform. Like a central inverter, the modular inverter can be conveniently located in a central position; and like a string inverter, the inverter’s modular nature allows for easy optimisation of the DC:AC ratio and also provides redundancy, as a malfunctioning unit or unscheduled maintenance only affects the inverter module’s own capacity while the remaining parallel segments continue to function.

While single-axis tracking systems that mount one module in a portrait configuration (known as “1P trackers”) are most common, trackers with two modules in a portrait configuration (known as “2P trackers”) are seeing more usage again after further refinement and improvements. These allow for reduced installation costs and increased bifacial uplift for modules that are higher off the ground and spaced further apart if the tracker design can accommodate the increased wind loadings of such configurations.

Solar module capacities have been rising over recent years, with modules on new utility-scale solar farms typically rated at around 600-700 Wp for projects in construction, and 650-750 Wp for projects in development. This increase in capacity is partly due to an increase in module efficiency, but mostly due to manufacturers increasing the physical size of the PV module; however, there is a practical limit to module size expansion due to handling and wind loading considerations. Key industry players are moving towards a standardised 3.1 $m^2$ module area.

Module manufacturer’s overcapacity for production and the USA’s tariff on PV has led to a significant reduction in the cost of solar panels by approximately 45% over the 2023-24 period[14].

Over the last few years, PV cell technology has been mostly dominated by gallium-doped p-type (replacing boron-doped p-type), which creates a performance boost through reduced Light Induced Degradation (LID). However, n-type TOPCon bifacial modules are now a standard offering for utility-scale projects which provide higher efficiency and reduced degradation. Major suppliers of PV modules have also discontinued their p-type production lines and switched to n-type.

Over the next few years, it is expected that other emerging PV technologies with advancements in efficiency and/or reduced degradation (such as heterojunction and tandem cells) will become commercially viable. In addition to these technology step changes, it can be expected that there will be a consistent improvement in PV efficiency and parameters such as increased module lifetime and decreased degradation.

### 4.4.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024, given the above discussion on typical options and current trends.

[14] https://www.pvxchange.com/Price-Index

Table 4-10 Configuration and performance

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology | | Single Axis Tracking (SAT) | Based on recent trends. |
| **Performance** | | | |
| 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 1.15 to 1.4 |
| Auxiliary power consumption | % | 2.9% | Very little auxiliary power consumption during operation but this figure is used to account for electrical distribution losses as well |
| Total plant size (Net) | MW (AC) | 200.0 | Auxiliary losses above are expected to be covered by module and inverter oversizing and accounted for in the energy generation model. |
| Seasonal Rating – Summer (Net) | MW (AC) | 200.0 | Thermal derating expected above 35°C with approximately 10% de-rate at 50°C, however these occurrences should be rare |
| Seasonal Rating – Not Summer (Net) | MW (AC) | 140.0 | Highly dependent on location. Approximately 20-30% reduction in peak power output in winter due to reduced irradiance |
| **Annual Performance** | | | |
| Average Planned Maintenance | Days / yr. | - | Included in EFOR below. |
| Equivalent forced outage rate (EFOR) | % | 1.50% | Based on 98.5% O&M availability. |
| Effective annual capacity factor | % | 29% | AC MW basis, highly dependent on location. Number based on a system installed in regional NSW. |
| Annual generation | MWh / yr. | 508,080 | Calculated from capacity factor above. |
| Annual degradation over design life | % | 0.35% | Using nameplate DC capacity as a basis. |

Table 4-11 Technical parameters and project timeline

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Technical parameters** | | | |
| Ramp Up Rate | MW/min | Resource dependent | |
| Ramp Down Rate | MW/min | Resource and system dependent | |
| Start-up time | Min | N/A | Within 5-10 minutes of sufficient irradiance after sunrise |
| Min Stable Generation | % of installed capacity | Near 0 | |
| **Project timeline** | | | |
| Time for development | Years | 2 – 3 | |

| Item | Unit | Value | Comment |
|---|---|---|---|
| First Year Assumed Commercially Viable for construction | Year | 2024 | |
| EPC Programme | Years | 1.5 | 18 months for NTP to COD. |
| Total lead time | Years | 1 | Time from NTP to first module on site. |
| Construction time | Weeks | 26 | Time from first inverter on site to COD. |
| Economic Life (Design Life) | Years | 30 | Typical given current PV module warranties |
| Technical Life (Operational Life) | Years | 30 | 40 if piles don't corrode and the spare parts remain available. |

### 4.4.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 4-12 Cost estimates**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX – EPC cost** | | | |
| Relative cost | $ / W (DC) | 1.15 | Relative cost does not include land and development costs. Relative cost reduced from last year due to a significant drop in module prices. A portion of this drop in module prices off-sets increased BOP costs and installation costs. However, overall effect is a drop in overall capex. |
| Total EPC cost | $ | 276,000,000 | |
| ▪ Equipment cost | $ | 165,600,000 | 60% of EPC cost – typical. |
| ▪ Installation cost | $ | 110,400,000 | 40% of EPC cost – typical. |
| **Other costs** | | | |
| Cost of land and development | $ | 16,560,000 | Assuming 10% of equipment cost. |
| Fuel connection costs | $ | N/A | |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / $MW_p$ (Net DC)/year | 12,000 | Includes allowance for general spare parts and scheduled replacement capex. Prices dropped in recent years due to increased competition, portfolio assets and O&M optimisation. |
| Variable O&M Cost | $ / MWh (Net) | - | Included in the fixed component. |
| Total annual O&M Cost | $ | 2,880,000 | Annual average cost over the design life |

## 4.5 Ocean and wave technologies

### 4.5.1 Overview

Ocean energy can be broadly considered as any form of renewable energy generated from the sea, with the following categories of ocean energy resources under consideration: wave, tidal range, tidal stream, thermal, and ocean currents. Wave energy is a derivative of wind energy, with the wind forming surface waves; tidal (stream and range) is the resultant of gravitational interactions between the earth's waters and the moon, sun, and other celestial bodies; ocean thermal energy is available where large temperature gradients exist in the ocean between warmer surface waters and colder deep waters; and ocean currents are driven by gravity, wind (the Coriolis Effect), salinity differences, and water density. Each ocean energy resource therefore has very different driving characteristics and potential mechanisms by which the theoretical energy contained within could be extracted.

Tidal range resources across the globe are geographically constrained to very specific locations, and the theoretical resource in Australia, although high, is concentrated within the King Sound and Joseph Bonaparte Gulf in the remote Kimberley region of Western Australia[15], and therefore far from grid infrastructure. This makes tidal range energy too niche, and unsuitable for making meaningful contribution in the NEM or WEM and is therefore considered to be outside the scope of this study.

Very limited deployment of Ocean Thermal Energy Conversion (OTEC) technology has taken place to date, with a 105 kW system currently being the largest system currently installed globally, at the Ocean Energy Research Center in Kailua-Kona, Hawaii[16]. The availability of thermal gradients in Australian waters sufficient to provide the necessary resource for an OTEC plant is limited to the far north of Queensland, making this technology an unattractive option for large-scale deployment within the NEM, and considered outside of the scope of this study.

Australia has four major currents within its territorial waters: the East Australian Current (EAC); the Leeuwin; the Antarctic Circumpolar Current; and the Indonesian Throughflow. The velocity of these currents is typically weak (with maximum horizontal velocity of less than 1 m/s), and, given the power output is proportional to the cube of the velocity, only limited power outputs can be achieved from conventional technology designs such as horizontal axis turbines (for comparison, a hypothetical horizontal axis turbine of 500 kW rated power and 20 m rotor diameter would need currents of almost 2 m/s in order to achieve rated power).

Tidal range, thermal, and ocean current resources have therefore been excluded from further analysis within this report, which instead will focus on wave energy and tidal stream energy.

Wave energy converters extract energy from the orbital motion of water particles within the waves. Conceptual technologies for harnessing the power of the waves have been the subject of research and development for a number of decades, with many pilot demonstration projects having taken place across Europe, North America, Asia, and Australia. However, commercially viable utility-scale wave farms are a future ambition rather than a present reality. A key challenge for wave energy converters is the need to survive the exceptional loads faced during extreme wave events but be able to economically generate power in average significant wave heights only a fraction of the extremes. It is important to note that there is no clear convergence upon any particular technology within the wave energy space, and a myriad of unique concepts exist, with no clear frontrunner in the pathway to commercialisation. Research undertaken by CSIRO[17] suggests that there is a strong theoretical wave energy resource in Australia, particularly around southern coastlines where strong winds in the Southern Ocean cause large consistent swell to travel northwards towards the Australian continent. Given the scale of the theoretical resource, wave energy remains an important subject of research and development.

Tidal stream is the horizontal flow of water caused by tides, generally as a result of two adjacent bodies of water being out of phase in tidal range, or where the movement of water is constrained between two or more land masses accelerating the flow. The kinetic energy from the moving body of water can be harnessed for energy production. The theoretical tidal stream resource is more limited in Australia than the theoretical wave energy resource, but tidal stream energy technologies are more mature in development and deployment than wave energy converters. Research carried out by a consortium of partners has identified a small number of locations where further work could be undertaken to assess the energy extraction potential in greater detail[18].

[15] Simon P. Neill, Mark Hemer, Peter E. Robins, Alana Griffiths, Aaron Furnish, Athanasios Angeloudis, Tidal range resource of Australia, Renewable Energy, Volume 170, 2021, Pages 683-692, ISSN 0960-1481, https://doi.org/10.1016/j.renene.2021.02.035.
[16] Makai Ocean Engineering, Ocean Thermal Energy Conversion, https://www.makai.com/renewable-energy/otec/, accessed October 2023
[17] https://www.csiro.au/en/research/natural-environment/oceans/wave-energy (Accessed October 2023)
[18] Penesis, I., Hemer, M., Cossu, R., Nader, J.R., Marsh, P., Couzi, C., Hayward, J., Sayeef, S., Osman, P., Rosebrock, U., Grinham. A., Herzfeld, M. and Griffin, D. (2020). Tidal Energy in Australia: Assessing Resource and Feasibility in Australia's Future Energy Mix. Australian Maritime College, University of Tasmania

### 4.5.2 Typical options

Offshore wave and tidal stream energy developments are critically dependent on:

- Access to seabed (for device foundations and/or mooring systems)
- Access to cable corridor and onshore land parcels (for onshore electrical balance of plant)
- Planning permissions / development consents
- Environmental approvals (and a pathway to achieving these in a nascent industry with no domestic precedent for large-scale arrays)
- Specialist vessel availability for construction and installation
- Nearby grid transmission capacity (the available resource is typically remote from major transmission links).

Wave and tidal energy converters are inherently subject to harsh conditions from the marine operating environment, and the expense of operation and maintenance at offshore locations. As such, concept and demonstration projects come at a significant expense, and targeted efforts are being made at addressing capital costs, operability, and maintainability. Due to the number of different concepts under development, and the operational principles that vary significantly between the technology types, typical options for wave and tidal stream energy will be discussed separately.

#### Wave energy options

Wave energy converters can be grouped according to the main principles of operation, with the following key wave energy technologies representing a significant proportion of prototypes under development:

- Oscillating water column (OWC)
- Point absorber
- Attenuator.

Other principles of wave energy converter operation do exist (eg flexible membrane, rotating mass, oscillating wave surge converter), and significant design diversity exists, even within each technology family.

Alongside the wave energy converter structure, station keeping and HV cable connection considerations also need to be borne in mind. The industry has been trending towards wet mate connection systems which can be coupled or decoupled whilst under water, reducing the time taken for operations.

#### Tidal stream energy options

Tidal stream energy converters have largely consolidated around the use of horizontal axis turbine designs, similar to the wind industry. The industry can be broadly separated into two distinct groupings of devices, based on the rotor diameter and power output of the devices:

- kW-class (typically 50 kW – 500 kW)
- MW-class (typically 1 MW – 1.5 MW per rotor, with some designs mounting multiple rotors on one foundation).

While there is convergence on turbine type, there is significant optionality in the form of foundation and mooring options for tidal stream energy converters. The following foundations have been used

- Monopile
- Pinned tri-pile
- Gravity base
- Floating platform with mooring lines and anchors.

As with wave, the tidal industry has been trending towards wet mate connection systems which can be coupled or decoupled whilst under water, reducing the time taken for operations.

### 4.5.3 Recent trends

While early-stage concept demonstration and pilot projects have been deployed for a number of ocean energy resources, tidal energy is the only resource that has seen commercial deployment in both tidal range (La Rance tidal barrage, France – 240 MW[19]; Lake Sihwa Tidal Power Plant, South Korea – 254 MW[20] both of which have been operating for significant periods of time and can be considered to be mature technologies) and tidal stream.

The longest-operating wave energy converter was a 400 kW OWC pilot plant on the island of Pico, Portugal, which operated between 1999 and 2018. Similar wave energy converter designs were deployed on the island of Islay, Scotland (LIMPET, 500 kW, operational from 2000-2012) and in the Bay of Biscay, Spain (Mutriku Wave Power Plant, 296 kW, 2011 – present). Waveswell, an Australian developer, has deployed a 200 kW OWC in King Island, Tasmania, which has been operational since June 2021. Other Australian developers of wave energy technology, such as Carnegie Clean Energy and Bombora Wave Power have relocated overseas for the continued development and offshore testing of their technologies. A wave energy demonstration project in King George Sound, WA, is ready for a six-month deployment. The “Moored MultiMode Multibody (M4)” project is a collaboration between the Marine Energy Research Centre at the University of Western Australia and the Commonwealth-funded Blue Economy Cooperative Research Centre. Data generated from this demonstration project will be made publicly available with the intention of boosting innovation. Swedish-Israeli developer Eco Wave Power has started construction of a megawatt-scale wave energy project near Porto, Portugal. When it comes to at-sea deployment, most of the wave energy devices that have undertaken sea trials have achieved operational testing in the order of months rather than years. Recent testing milestones have been achieved by Mocean Energy and CorPower Ocean with regards to survivability during storms, and continuous power production during normal operations.

Given the technological diversity within the ocean energy space, the trends within wave and tidal stream are reflective of the technology maturity. There exist at least 16 major wave energy test centres around the world[21], many of which are grid connected. The majority of wave energy converter test programmes have been undertaken in within existing test centres, but a number of operational prototypes have also been deployed at discrete locations outside of these test facilities.

Following a number of technology challenges and commercial setbacks in the UK, research and development funding transitioned from the funding of "full-scale” devices towards supporting early development of subsystems and components that could provide solutions for future wave energy converter systems, and for testing of novel concepts at tank-scale and part-scale. Wave Energy Scotland was set up as a mechanism to stimulate and drive innovation in the wave energy sector, with a competitive procurement programme focused on the key systems and sub systems associated with wave energy converters.

The US Department of Energy has focused recent funding on wave energy converter concepts that are suitable for remote or small-scale grids, on environmental monitoring technologies, and on instrumentation and control system technologies that could be implemented in future wave energy converters. Recent wave energy converter deployments include Wave Swell Energy’s 200 kW UniWave200 (King Island, Tasmania) and the 600 kW CorPower C4 (Aguçadoura, Portugal test facility, operated by WavEC).

Significant advances have been made in tidal stream with the deployment of pre-commercial arrays of multiple devices, including Meygen Tidal Energy Project Phase 1, Scotland – 6 MW[22] and the Shetland Tidal Array, Scotland – 600 kW[23]. In the APAC region, a 500 kW variant of Simec Atlantis Energy (SAE) turbine was deployed in the straits of Naru Island, Japan. Several projects have successfully delivered energy to the grid. Several European-funded research projects have funded the tidal stream energy sector in targeted projects with specific performance goals and objectives that include demonstration of cost reduction pathways for tidal stream, and deployment of multiple device arrays. The leading tidal stream energy test facility, the European Marine Energy Test Centre (EMEC) has facilitated the largest number of grid-connected trials of prototype devices, but other full-scale test centres exist in The Bay of Fundy, Canada

[19] Tethys database, https://tethys.pnnl.gov/project-sites/la-rance-tidal-barrage, accessed October 2024
[20] Tethys database, https://tethys.pnnl.gov/project-sites/sihwa-tidal-power-plant, accessed October 2024
[21] Aderinto, Tunde & Li, Hua. (2019). Review on Power Performance and Efficiency of Wave Energy Converters. Energies. 12. 4329. 10.3390/en12224329.
[22] Tethys database, https://tethys.pnnl.gov/project-sites/meygen-tidal-energy-project, accessed October 2024
[23] Tethys database, https://tethys.pnnl.gov/project-sites/nova-innovation-shetland-tidal-array, accessed October 2024

(Fundy Ocean Research Center for Energy – FORCE), the Perpetuus Tidal Energy Centre in the UK, and Paimpol-Bréhat in France.

Due to the nature of early-stage prototyping and first of a kind system costs, there is limited information available in the public domain and cost data for wave and tidal stream energy projects is scarce. Many cost estimates within academic research utilise future cost projections based on assumed learning rates. As such, there are no recent publicly available project cost benchmarks that reflect firm as-built costs, and the cost data presented within the following section contains inherent uncertainty.

### 4.5.4 Selected hypothetical wave energy project

The following tables outline the technical parameters for the hypothetical project upon which costing is based. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024, given the above discussion on typical options, current trends, and the suitability of the Australian resource.

**Table 4-13 Configuration and performance**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology / OEM | | Generic wave energy converter | Other options include Mocean Energy, Waveswell, Carnegie, CorPower Ocean, Bombora (noting each technology is unique in principles of operation). |
| Make model | | N/A | Based on theoretical installation |
| Unit size (nominal) | MW | 0.200 | ISO / nameplate rating. N.B., the unit size is very much dependent on technology type. No convergence around a typical value. Given no arrays have yet been delivered, it is assumed unit capacity will not step up significantly for first arrays. |
| Number of units | | 10 | |
| **Performance** | | | |
| Total plant size (Gross) | MW | 2.00 | |
| Auxiliary power consumption | - | 3% | No significant auxiliary power consumption during wave farm operation but there are electrical distribution losses from the wave energy converters to the substation. |
| Total plant size (Net) | MW | 1.94 | |
| Seasonal rating – Summer (Net) | MW | 1.94 | No seasonal changes in plant rating. |
| Seasonal rating – Not Summer (Net) | MW | 1.94 | No seasonal changes in plant rating. |
| **Annual Performance** | | | |
| Average planned maintenance | Days / year | - | Included in EFOR below. |
| Equivalent forced outage rate | - | 20% | Estimate based on anticipated pre-commercial early demonstration arrays |
| Effective annual capacity factor (P50, year 0) | - | 35%[24] | Capacity factor for wave energy is dependent on the site-specific resource, and the type of wave energy converter. A theoretical power matrix presenting the power output for given ranges of significant wave height and wave period must be compared to the resource matrix for the proposed location. An estimate of 35% has been used. |

[24] J Hayward, CSIRO, Wave energy cost projections, A report for Wave Swell Energy Limited, Table 3 Key assumptions, https://arena.gov.au/assets/2021/10/wave-energy-cost-predictions-a-report-for-wave-swell-energy-limited.pdf

| Item | Unit | Value | Comment |
|---|---|---|---|
| Annual generation | MWh | 5,948 | Provided for reference. |
| Annual degradation over design life | - | 0.1% pa | Assuming straight line degradation, ie, proportion of initial energy production. |

**Table 4-14 Technical parameters and project timeline**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Technical parameters** | | | |
| Ramp up rate | MW/min | Resource dependent | |
| Ramp down rate | MW/min | Resource dependent | Full ramp down of array on command if required by the Network Service Provider in a contingency event. |
| Start-up time | Min | N/A | Always on, except when under maintenance. |
| Min stable generation | % of installed capacity | Near 0 | |
| **Project timeline** | | | |
| Time for development | Years | 5 | Estimate. Includes pre-feasibility, design, approvals, consenting etc. For wave energy, a key factor is the availability of wave resource data. Installing waverider buoys at the nominated location for sufficient duration to derisk can add several months to detailed feasibility assessments. Obtaining development approvals and consents can also add considerable time to the overall development schedule, particularly given no precedent exists for commercial deployment of wave farms. |
| First year assumed commercially viable for construction | Year | 2024 | |
| EPC programme | Years | 2 | For NTP to COD. |
| ▪ Total lead time | Years | 1 | Time from NTP to first wave energy converter delivered to site. |
| ▪ Construction time | Weeks | 52 | Time from first wave energy converter installation to Wave Farm Practical Completion. |
| Economic Life (Design Life) | Years | 20[25] | Anticipated design life, based on published research. |
| Technical Life (Operational life) | Years | 25[25] | Estimated operational life, based on published research. |

[25] Pencock, S., et al., Deriving Current Cost Requirements from Future Targets: Case Studies for Emerging Offshore Renewable Energy Technologies

### 4.5.5 Cost estimate – wave energy

**Table 4-15 Cost estimates (wave energy)**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX Construction** | | | |
| Relative cost | $ / kW | 14,670[25] | Estimate based on upper value within academic research, adjusted for inflation. Initial projects would not be expected to have achieved cost reductions to a level where the technology can be commercially competitive with other alternatives such as solar and wind. No commercial arrays yet exist in Australia or in the world, only prototype deployments and one of a kind installations, but nothing can be considered an array (which would be multiple units of the same type installed in the same location). |
| Total cost | $ | 29,340,000 | |
| ▪ Equipment cost | $ | 23,472,000 | 80% of EPC cost (and upper bound of the CAPEX range). |
| ▪ Installation cost | $ | 5,868,000 | 20% of EPC cost (and upper bound of the CAPEX range). |
| **Other costs** | | | |
| Cost of seabed lease and development | $ | 821,520 | Assuming 2.8% of CAPEX, and upper bound of the CAPEX range. Note seabed for wave farms is anticipated to be leased. |
| Fuel connection costs | $ | N/A | |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / MW (Net) | 520,000 | Assumed as 4% of CAPEX |
| Variable O&M Cost | $ / MWh (Net) | - | Included in the fixed component. |
| Total annual O&M Cost | $ | 1,040,000 | Annual average cost over the design life. |

### 4.5.6 Selected hypothetical tidal stream project

The following tables outline the technical parameters for the hypothetical project upon which costing is based. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024, given the above discussion on typical options, current trends, and the suitability of the Australian resource.

**Table 4-16 Configuration and performance**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology / OEM | | Nova Innovation | Other options include Andritz Hydro, Atlantis Resources, Orbital Marine Energy, Tocardo, Schottel, |
| Make model | | M100D | Based on most recent installations |
| Unit size (nominal) | MW | 0.1 | ISO / nameplate rating |
| Number of units | | 20 | |
| **Performance** | | | |
| Total plant size (Gross) | MW | 2 | |
| Auxiliary power consumption | - | 3% | No significant auxiliary power consumption during wind farm operation but there are electrical distribution losses from the turbines to the substation. |

| Item | Unit | Value | Comment |
| --- | --- | --- | --- |
| Total plant size (Net) | MW | 1.94 | |
| Seasonal rating – Summer (Net) | MW | 1.94 | No seasonal changes in plant rating. |
| Seasonal rating – Not Summer (Net) | MW | 1.94 | No seasonal changes in plant rating. |
| **Annual Performance** | | | |
| Average planned maintenance | Days / year | - | Included in EFOR below. |
| Equivalent forced outage rate | - | 5% | Based on reported availability |
| Effective annual capacity factor (P50, year 0) | - | 34% | Based on MeyGen reported data |
| Annual generation | MWh | 5,780 | Provided for reference. |
| Annual degradation over design life | - | 0.1% pa | Assuming straight line degradation, ie, proportion of initial energy production. |

**Table 4-17 Technical parameters and project timeline**

| Item | Unit | Value | Comment |
| --- | --- | --- | --- |
| **Technical parameters** | | | |
| Ramp up rate | MW/min | Resource dependent | |
| Ramp down rate | MW/min | Resource dependent | Full ramp down of array on command <30s if required by the Network Service Provider in a contingency event. |
| Start-up time | Min | N/A | Always on. < 5 min after maintenance shutdown. |
| Min stable generation | % of installed capacity | Near 0 | |
| **Project timeline** | | | |
| Time for development | Years | 4 – 5 | Estimate. Includes pre-feasibility, design, approvals, consenting etc.<br>For tidal stream, a key factor is the availability of tidal flow velocity resource data. Installing Acoustic Doppler Current Profilers (ADCP) at the nominated project location can add >6 months to detailed feasibility assessments, pushing the timeframe to the upper end of the scale. Obtaining development approvals and consents can also add considerable time to the overall development schedule, particularly given no precedent exists for commercial deployment of wave farms |
| First year assumed commercially viable for construction | Year | 2024 | |
| EPC programme | Years | 2 | For NTP to COD. |
| ▪ Total lead time | Years | 1 | Time from NTP to first turbine delivered to site. |
| ▪ Construction time | Weeks | 52 | Time from first tidal turbine installation to Tidal Farm Practical Completion. |
| Economic Life | Years | 20 | Typical expected design life. |
| Technical Life (Operational Life) | Years | 20 | Typical expected operational life. |

### 4.5.7 Cost estimate – tidal stream

**Table 4-18 Cost estimates of hypothetical tidal stream project**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX Construction** | | | |
| Relative cost | $ / kW | 12,190[25] | Based on upper value within academic research, adjusted for inflation. Initial projects would be expected to be at the upper end of the range. N.B., reporting on the MeyGen project[26] identified that the cost per kW was approximately $19,000 / kW (when adjusted for inflation and ForEx). |
| Total cost | $ | 24,380,000 | |
| ▪ Equipment cost | $ | 19,504,000 | 80% of EPC cost. |
| ▪ Installation cost | $ | 4,876,000 | 20% of EPC cost. |
| **Other costs** | | | |
| Cost of land and development | $ | 800,000 | Assuming 3.3% of CAPEX. Note seabed for tidal arrays is typically leased. |
| Fuel connection costs | $ | N/A | |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / MW (Net) | 487,600 | Assumed as 4% of CAPEX |
| Variable O&M Cost | $ / MWh (Net) | - | Included in the fixed component. |
| Total annual O&M Cost | $ | 975,200 | Annual average cost over the design life. |

## 4.6 Concentrated solar thermal

### 4.6.1 Overview

Concentrated solar thermal (CST) technology in power generation applications generally refers to using mirrors to collect solar energy over a wide area and then concentrating the reflected energy onto a solar receiver. The energy is then captured by a thermal fluid which is cycled through the receiver and either stored or used directly for power generation.

There are four[27] primary types of CST power plants currently available in the market. These include:

- Parabolic Trough Collectors – Parabolic Trough systems consist of parabolic, trough-shaped solar collectors which concentrate the sun rays onto a tubular heat receiver placed at the focal line of the solar collector. A single-axis tracking system is used to orient the solar collectors toward the sun.
- Linear Fresnel Collectors – This technology uses long flat, or slightly curved, mirrors placed at different angles. These move independently on a single axis, to concentrate the sunlight on either side of a fixed receiver. The fixed receivers are mounted above the mirrors on towers.
- Solar Tower – Solar tower technologies use a ground-based field of sun-tracking mirrors or heliostats to focus sunlight onto a receiver mounted on top of a central tower. The heliostats use two-axis tracking systems to follow the sun.
- Parabolic Dish – This technology consists of a parabolic dish-shaped concentrator that reflects the solar direct radiation on to a receiver placed at the focal point of the dish. The dish-shaped concentrators are mounted on structures with two-axis tracking systems that follow the sun. The collected heat is used

[26] Black & Veatch, Lessons Learnt from MeyGen Phase 1A Final Summary Report, 2020
[27] There are a number of concentrated PV technologies under development including towers and dishes that focus solar radiation onto PV cells but these are not included here as they don't use a heat transfer fluid to collect and transport solar energy.

directly by a heat engine mounted on the receiver. Typical heat engine cycles deployed are Stirling or Brayton cycle (micro-turbine).

Parabolic trough collectors are by far the most mature technology and account for the largest number of installations globally. Solar tower projects are emerging as the preferred technology with several large-scale solar tower commercial plants under construction or operation globally. Linear Fresnel and parabolic dish systems are still in pilot or demonstration phase.

The key advantage of concentrated solar thermal, in comparison to solar PV and wind technologies, is its ability to incorporate thermal energy storage which increases its capacity factor, shifts generation to the evening peak and overnight, and allows the plant to be dispatched. Solar tower projects typically generate power by using the energy stored in solar salt to raise steam which is then passed through a steam turbine in a conventional Rankine cycle. By using a steam turbine, they can provide system inertia which is critical to grid operation in areas with increasing penetration of variable renewable energy generation from solar PV and wind. Further, the steam turbines used in CST plants may incorporate a clutch which enables the turbine to act as a synchronous condenser even at times when the plant is not dispatching energy into the grid.

Solar thermal plants (in particular central tower plants) have high capital cost compared to other renewable energy technologies, with the solar field (heliostats, receivers, towers, heat transfer system etc) comprising the largest component of overall cost. However, their ability to provide dispatchable renewable energy with storage and system inertia means that the output of solar thermal plants can be more valuable than variable renewable energy generation. A significant parallel market is emerging in Australia and internationally for CST plants to provide high-temperature process heat as a replacement for fossil fuel boilers, thereby offering a decarbonisation option. Remote power supply and green fuel production are also emerging as key applications for CST. Significant CST cost reductions are expected in the components as design and manufacturing matures, plant sizes increase and total installed capacity grows.

The O&M requirements of CST plants are lower in comparison to fossil fuel plants but still significant, much of which relates to fixed labour costs. Key O&M costs include operations personnel, mirror cleaning (including water consumption), and plant insurance. O&M costs for the steam cycle and BOP (i.e. steam turbine, cooling system, electrical systems, etc) are similar to traditional thermal plant O&M costs. Opportunities exist to minimise O&M costs, such as only operating the power train during the evening peak and overnight, eliminating the need for a daytime operating crew for the power train.

### 4.6.2 Typical options

Utility-scale plants currently under construction globally are either parabolic trough or solar tower technology ranging from 50 MW to 700 MW with storage between 9 hours and 17.5 hours. Parabolic trough technology is quite mature and large plants can achieve economy of scale benefits over fixed costs such as grid connection. The Noor Energy 1 project in UAE was completed in late 2023 and incorporates 600 MW of parabolic trough CST in three plants of 200 MW to supplement the recently completed 100 MW central tower plant and 250 MWac of PV.

For tower technology, increases in project scale can drive reductions in costs and levelised cost of energy through manufacturing efficiencies for the heliostats and other components, plant O&M and in the steam turbine efficiency which is highly dependent on size. However, increasing the size of centralised solar tower projects also creates engineering challenges as the outer heliostats are further from the receiver and must be able to focus accurately over a large distance, typically requiring significant stiffness in structure. As a result, central tower projects currently under construction are mostly around 100 MW in capacity. The Three Gorges CST project currently being commissioned in China incorporates two 50 MW towers and solar arrays to supply heat to a single 100 MW power block, thus addressing the challenges of optical attenuation while retaining the efficiency of a larger steam turbine, while Power China Northwest recently announced the start of construction of a 200 MW single tower project in western Haixi.

The Vast Solar technology developed in Australia is seeking to overcome the scale challenge through the use of a modular approach with many smaller arrays of heliostats focusing on shorter towers. This configuration is enabled by the use of liquid sodium as the heat transfer fluid, which has a number of advantages over molten salt, the most significant being the lower freezing point (around 98°C compared to around 220°C for solar salts which are typically a mixture of sodium and potassium nitrates). The lower melting point of sodium means the heat transfer fluid can be more easily transported over long distances with trace heating in pipework to maintain the liquid state and to readily melt the sodium if it does freeze. Other companies are exploring the benefits of modular CSP technology including Heliogen in Australia.

Due to the nature of the solar tower technology, through concentrating the solar energy to a single focal point, this technology can produce the highest temperatures and hence offers improved steam cycle efficiencies over the parabolic trough alternatives as well as reduced thermal storage requirements. Significant research and development is underway in Australia and globally to develop the next generation of solar thermal technologies with temperatures of 700°C and above in order to improve efficiency and reduce the cost of delivered energy, and alternative heat transfer mechanisms including a falling particle curtain.

### 4.6.3 Recent trends

Solar thermal capacity grew six-fold globally between 2010 and 2020 on the back of incentive schemes in key markets like Spain and the USA. From 2015 to 2021, approximately 2.6 GW of CST was installed globally, particularly the Middle East, North Africa, and China. In 2023, the total installed capacity of concentrated solar thermal power (CST) grew 400 MW through completion of the Noor 1 parabolic trough system to reach around 7 GW[8]. The 100 MW central tower portion of Noor 1 was completed in early 2024 and the 100 MW Redstone central tower project in South Africa was recently completed after significant delays.

China is currently the most active CST market. It announced a feed in tariff for CST in 2016 and recently released a new regulation requiring a dispatchable portion in new large-scale renewable energy installations, which has led to the development of several large hybrid projects including wind, solar PV and CST. Around 1 GW of projects are reported to be in construction with a further 3 GW in development.

Global growth in CST is expected to accelerate with the International Energy Agency forecasting a 10x increase in concentrating solar thermal power (CSP) installations globally by 2030 to 73 GW (by 2030), 281 GW (by 2040) and 426.5 GW (by 2050)[28]. At the end of 2023, global CST planned capacity was over 8 GW, with expansion planned in China, South Africa, and Saudi Arabia. Several other countries announced their intentions to tender new CST plants including India, Kuwait, Egypt and Botswana.

Molten salt is the current preferred heat transfer fluid for solar tower technology, while mineral oils continue to be preferred for parabolic trough technology. New solar tower and parabolic trough plants typically use molten salt for thermal storage.

Plant capacity factors have been increasing over time to above 50% with larger thermal storage capacities of over 8 hours. Capital costs have also been trending steadily downwards, reducing by around 50% between 2010 and 2020 to USD4,746/kW[29]. With few projects completed in the last few years, there is limited data available to analyse cost trends, compounded by the evolution of hybrid plants with multiple technologies.

Most new international CST projects are hybrid projects combing CST with solar PV and wind for the lowest levelised cost of energy for dispatchable renewable energy. Solar PV and wind generation is exported to the grid during the day and energy captured by the CST arrays during the day is stored in molten salt tanks to be used for generation overnight (sometimes referred to as “night-time solar”). Batteries can be included for short-term smoothing and shifting, and the hybrid plant can be optimised for the dispatch scenario. In some countries, larger salt tank heating coils are being used to enable storage of cheap solar PV generation from the grid during the day for additional generation at night.

In Australia, there is currently no utility-scale concentrated solar thermal project in commercial operation. However, several projects are being developed, the most advanced being a 30 MW reference plant at Port Augusta with sufficient energy storage for an 8-hour power generation phase over the afternoon/evening electricity demand peak. The project is currently finalising funding and procurement with financial close expected in early 2025

Given the lack of constructed projects in Australia, there is limited information on the actual costs of solar thermal projects in the region. To address this issue, the Australian Solar Thermal Research Institute (ASTRI) commissioned a report (https://www.solaratnight.com.au/press-releases/the-australian-concentrating-solar-thermal-value-proposition-full-report) by the German engineering firm Fichtner on the

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[28] Net Zero by 2050: A Roadmap for the global energy sector, International Energy Agency (2021)
[29] Renewable Power Generation Costs in 2021, IRENA

value proposition for CST in Australia, which includes cost estimates based on Fichtner's international experience, budget pricing information provided by equipment suppliers, and stakeholder engagements. Fichtner developed a cost model for different plant configurations, broken down into the three main systems that drive the bulk of the project cost: solar field, thermal energy storage and power block, with the following specific costs for a reference design based on the NSW Med cost region as the most likely deployment.

**Table 4-19 Summary of Fichtner cost model as at October 2023**

| System | Value | Specific Cost | Total Cost (AUDm) |
|---|---|---|---|
| Power block net capacity (MWe) | 140 | 2,028,795 | 284 |
| Thermal energy storage (MWth) | 4667 | 35,880 | 167 |
| Solar field (MWth) | 720 | 644,320 | 464 |
| **EPC Cost** | | | **915** |

Assuming EPC delivery of the three main systems, Fichtner has included an additional allowance of 20% for indirect costs and 5% for owner costs including land cost, development cost, utility connections and additional owner's cost during construction and commissioning. We have provided a separate estimate for land and development costs below but have not reduced the estimate based on the Fichtner costs for clarity.

Fichtner has also included an additional 13% escalation to reflect global supply chain issues currently being experienced. The Fichtner report provides scaling factors to allow users of its model to estimate costs for different plant configurations. The Fitchner reference design configuration and cost model represent the current best estimate of CST for the Australian market so these have been used in the estimate below, but adopting the VIC Low region costs as the basis of these costs.

The Fichtner cost modelling predicted a cost reduction between 2023 and 2024 of around 4% based on longer-term learning rate forecasts. However, as noted above there is limited data available from international projects to validate this cost reduction. Average OECD inflation over the last 12 months has been around 4-5% which offsets the expected reduction in costs so the Fichtner costs from October 2023 have been escalated by 4% to represent current values.

### 4.6.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024, given the above discussion on typical options and current trends and referring to analysis completed in early 2024 by ITP Renewables for ASTRI. The ITP analysis examined different CSP configurations and concluded that around 16 hours of storage was likely to achieve the lowest levelised cost of energy in most locations. In high irradiance locations in the NEM such as Longreach, such a system would have a net capacity factor of around 71% while the same plant in lower irradiance locations such as Wagga Wagga would have a net capacity factor of around 57%. Projects in lower irradiance locations may achieve superior economics from other value capture opportunities arising from CSP's storage, flexibility and ability to provide system inertia. For the purposes of this report, the ITP scenario of 16 hours storage in Longreach has been used as the selected hypothetical project. The power cycle efficiency has decreased from 45% in last year's report to 42% this year to align with the ITP scenario, and the net capacity factor has increased significantly from 50% to 71% for the same reason.

**Table 4-20 Configuration and performance**

| 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 energy during the day and generating for 16 hours through evening peak and overnight period eg 5pm to 8am |

| Item | Unit | Value | Comment |
|---|---|---|---|
| Solar field capacity | MWth | 720 | Based on Fichtner reference design for Longreach |
| Power block | | 1 x Steam Turbine, dry cooling system | |
| Capacity | MW | 140 | Based on typical options and recent trends, 140MW with 16 hours thermal energy storage is selected |
| Power cycle efficiency | % | 42 | Typical |
| Heat transfer fluid | | Molten salt | Molten salt is currently the preferred heat transfer fluid for central tower CSP technology |
| Storage | Hours | 16 | As mentioned in Section 4.6.3, almost all recent projects have a thermal energy storage component. 16 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 |
| Auxiliary power consumption | % | 6.7% | |
| Total plant size (Net) | MW | 140 | 25°C, 110 metres, 60%RH |
| Seasonal Rating – Summer (Net) | MW | 140 | |
| Seasonal Rating – Not Summer (Net) | MW | 140 | |
| **Annual Performance** | | | |
| Average Planned Maintenance | Days / yr. | 7 | Based on published figures[30]. |
| Equivalent forced outage rate | % | 3% | Based on published figures |
| Effective annual capacity factor | % | 71% | Based on ITP analysis for ASTRI |
| Annual generation | MWh / yr. | 870,744 | Provided for reference |

**Table 4-21 Technical parameters and project timeline**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Technical parameters** | | | |
| Ramp Up Rate | MW/min | 6 | Based on 4% of turbine maximum output |
| Ramp Down Rate | MW/min | 6 | Based on 4% of turbine maximum output |
| Start-up time | Minutes | Hot: 4<br>Warm: 50<br>Cold: –n/a | Standard operation. Cold start time not included as a CST plant should always remain warm. |
| Min Stable Generation | % of installed capacity | 20% | |
| **Project timeline** | | | |

[30] Alinta, 2015. Port Augusta Solar Thermal Generation Feasibility Study

| Item | Unit | Value | Comment |
|---|---|---|---|
| Time for development | Years | 2 – 3 | includes pre/feasibility, design, approvals etc. |
| First Year Assumed Commercially Viable for construction | Year | 2024 | |
| Total EPC programme | Years | 2-3.5 | 42 months from NTP to COD for central tower; 24 months for modular tower. |
| ▪ Total Lead Time | Years | 1.75 | Time from NTP to main equipment on site. |
| ▪ Construction time | Weeks | 91 | Time from main equipment on site to COD. |
| Economic Life (Design Life) | Years | 30 | |
| Technical Life (Operational Life) | Years | 40 | |

### 4.6.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 4-22 Cost estimates**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX – EPC cost** | | | |
| Relative cost | $ / kW (gross) | 6,104 | Based on Fichtner cost model for VIC Low with 4% inflation from October 2023 |
| Total EPC cost | $ | 915,655,000 | |
| ▪ Equipment cost | $ | 686,742,000 | 75% of EPC cost – typical |
| ▪ Construction cost | $ | 228,914,000 | 25% of EPC cost – typical |
| **Other costs** | | | |
| Cost of land and development | | 32,000,000 | Land required expected to be circa 700ha at typical cost of $20,000 per ha and development cost of circa 2% of capex |
| Fuel connection costs | | N/A | |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / MW | 122,087 | 2% of CAPEX (based on ITP report T0036, “Informing a CSP Roadmap for Australia.” |
| Variable O&M Cost | $ / MWh | - | Included in fixed component |
| Total annual O&M Cost | $ | 18,313,050 | Annual average cost over the design life |

## 4.7 Reciprocating engines

### 4.7.1 Overview

Reciprocating engines are a widespread and well-known technology used in a variety of applications. They are typically categorised by speed, stroke, configuration, and ignition/fuel type.

For power generation applications, reciprocating engines are coupled to a generator on the same base frame. For grid scale applications, centralised installations are typically installed in a common powerhouse structure or unit enclosures in a multi-unit configuration with separate cooling systems, air intake/filter, exhaust silencer, stack structure, etc.

Reciprocating engines utilise synchronous generators, which provide high fault current contribution and support the NEM system strength.

### 4.7.2 Typical options

For power generation applications, there are two general classifications of reciprocating engine - medium-speed and high-speed. Medium-speed engines operate at 500 – 750 rpm and typically range in output from 4 to 18 MW. High-speed engines operate at 1,000 – 1,500 rpm with a typical output below 4 MW.

Additionally, there are three general fuel classes for reciprocating engines. These are gaseous fuel, liquid fuel, and dual fuel. Gaseous fuel engines - also known as spark ignition engines - operate on the thermodynamic Otto cycle, and typically use natural gas as the fuel source. Liquid fuel engines operate based on the thermodynamic Diesel cycle, and typically use no. 2 diesel (or light fuel oil) as the fuel source. Dual fuel engines can operate on either gaseous or liquid fuel, however, always rely on a small consumption of diesel as a pilot fuel.

With respect to hydrogen fuel, OEMs advise that current reciprocating engines can typically operate with a hydrogen blend of between 5-25% with natural gas. Depending on the hydrogen blend percentage and the OEM, engine modifications to the engine intake manifold, and fuel rail and port injection into cylinder head may be required. One OEM is now offering a 100% hydrogen reciprocating engine product.

### 4.7.3 Recent trends

#### General

Traditionally multi-unit reciprocating engine installations on the NEM have consisted of high-speed spark-ignition engines, fuelled from coal seam methane or waste gas where the fuel gas is not suited to gas turbines. Installed capacities of these power stations are in the <50 MW range. Historically, capacity factors have been dependent on fuel gas availability.

Given the degree of uncertainty around medium to long-term market conditions, some developers are considering large-scale medium-speed reciprocating engine power stations for firming applications. This is driven by their favourable fuel efficiency merits, and high degree of flexibility in start times, turn-down, and response with renewable energy variability in the electricity network. This provides a strong business case for a wide range of capacity factors.

AGL's Barker Inlet Power Station is currently the only large-scale medium-speed reciprocating engine power station in operation on the NEM which commenced commercial operation in 2019. Pacific Energy has also entered into an agreement to supply a similar scale (165 MW) power station to supply power to FMG's Solomon mine in Western Australia's Pilbara region using medium speed gas engines[31]. The facility entered into operation in 2023.

Other large-scale medium-speed installations for the NEM which are in the planning phase include the following. These however are yet to be progressed to a financial investment decision:

- AGL's Barker Inlet Power Station (Stage 2 – 210 MW)

Other gas reciprocating engine power plants under development stage include:

- Lochard Energy Winton Energy Reserve 1 Project (200 MW gas power generator with BESS)[32].

Equipment pricing is not expected to decrease materially in the near future. Marginal performance improvements are also expected over time with ongoing technology developments.

Dual fuel (natural gas and liquid fuel (e.g. diesel) solutions are still being considered with liquid fuel used as a secondary fuel in case of an emergency and non-supply of gas fuel.

[31] https://www.businessnews.com.au/article/FMG-approves-570m-energy-spend
[32] https://www.lochardenergy.com.au/energy-reserve-1-2 /

### Hydrogen

There is a trend for reciprocating engine solutions to be planned to move towards low emissions solutions with either blending of or firing completely on hydrogen. All new reciprocating engine projects are expected to include readiness/capability for hydrogen blending and eventual conversion to hydrogen firing should hydrogen fuel become more readily available.

There are projects in Australia either greenfield or brownfield that are investigating using a hydrogen blended fuel with natural gas for power generation based on current activity in the renewable hydrogen industry. Some of these projects include:

- A power station expansion (30 MW) with reciprocating engines that are hydrogen ready with a natural gas with hydrogen blend capability of up to 25% initially without material engine modifications.
- A renewable energy precinct producing renewable hydrogen from curtailed renewable energy for peaking power generation from a new nominal 12 MW reciprocating engine using a 25% hydrogen blend with natural gas (NEM connected)
- A renewable energy hybrid power system with renewable hydrogen produced from curtailed renewable energy for power generation from existing nominal 4 MW reciprocating engine(s) using a 10% hydrogen blend with natural gas (not NEM connected).

Testing programs by OEMs for higher hydrogen blend percentages with natural gas continues up to 60% and beyond for their reciprocating engine product line. One OEM offers 100% hydrogen capable Type 4 engines.[33] Other OEMs plan to be able to offer 100% hydrogen capability by 2025 and beyond.

Hyosung Heavy Industries is developing the first pilot power plant project (1 MW) in APAC that will be fuelled by 100% hydrogen. The power plant commenced operation in April 2024[34].

## 4.7.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024 given the above discussion on typical options and current trends.

**Table 4-23 Configuration and performance**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology / OEM | | Wartsila | MAN Diesel and Rolls Royce Bergen (RRB) also offer comparable engine options. |
| Make model | | 18V50DF | Including SCR for $NO_x$ 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 | |
| **Performance (natural gas)** | | | |
| Total plant size (Gross) | MW | 211.2 | 25°C, 110 metres, 60%RH |
| Auxiliary power consumption | % | 1% | Excludes intermittent auxiliary loads. Overall average consumption could be closer to 2.5%. |
| Total plant size (Net) | MW | 209.1 | 25°C, 110 metres, 60%RH. Performance on natural gas. No output derate considered for hydrogen blend. OEM to be consulted for performance derate. |

[33] https://www.jenbacher.com/en/energy-solutions/energy-sources/hydrogen
[34] https://www.businesskorea.co.kr/news/articleView.html?idxno=216807

| Item | Unit | Value | Comment |
|---|---|---|---|
| Seasonal Rating – Summer (Net) | MW | 209.1 | Derating does not typically occur until temperatures over 38 – 40°C. |
| Seasonal Rating – Not Summer (Net) | MW | 209.1 | |
| Hydrogen demand at maximum operation | kg/h (HHV) | 1237 | 25% hydrogen |
| Heat rate at minimum operation | (GJ/MWh) LHV Net | 10.259 | 25°C, 110 metres, 60%RH. Assuming minimum operation on gas fuel. |
| Heat rate at maximum operation | (GJ/MWh) LHV Net | 7.940 | 25°C, 110 metres, 60%RH. Gas fuel operation. |
| Thermal Efficiency at MCR | %, LHV Net | 45.3% | 25°C, 110 metres, 60%RH. Gas fuel operation. |
| Heat rate at minimum operation | (GJ/MWh) HHV Net | 11.356 | 25°C, 110 metres, 60%RH. Gas fuel operation. |
| Heat rate at maximum operation | (GJ/MWh) HHV Net | 8.790 | 25°C, 110 metres, 60%RH. Gas fuel operation. |
| Thermal Efficiency at MCR | %, HHV Net | 40.9% | 25°C, 110 metres, 60%RH. Gas fuel operation. |
| **Annual Performance** | | | |
| Average Planned Maintenance | Days / yr. | 2.7 | Based on each engine only running 2190 hours per year. |
| Equivalent forced outage rate | % | 2% | |
| Annual capacity factor | % | 25% | Typical average for current planned firming generation dispatch |
| Annual generation | MWh / yr. | 457,903 | Provided for reference based on assumed capacity factor. |
| Annual degradation over design life - output | % | 0% | Assuming straight line degradation. |
| Annual degradation over design life – heat rate | % | 0.05% | Assuming straight line degradation. |

Table 4-24 Technical parameters and project timeline

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Technical parameters** | | | |
| Ramp Up Rate | MW/min | 36 | Station ramp rate (all units) under standard operation. Based on OEM data. |
| Ramp Down Rate | MW/min | 36 | Station ramp rate (all units) under standard operation. Based on OEM data. |
| Start-up time | Min | 10 | Standard operation. Based on OEM data. 5-minute fast start is available. |
| Min Stable Generation | % of installed capacity | 40% | Can turn down to 10% on diesel operation. Based on OEM data. |
| **Project timeline** | | | |
| Time for development | Years | 2 | includes pre/feasibility, design, approvals, procurement, etc. |
| First Year Assumed Commercially Viable for construction | Year | 2024 | |
| EPC programme | Years | 2-2.5 | For NTP to COD. |

| Item | Unit | Value | Comment |
|---|---|---|---|
| ▪ Total Lead Time | Years | 1-1.5 | 12-18 months typical to engines on site. |
| ▪ Construction time | Weeks | 52 | 12 months assumed from engines to site to COD. |
| Economic Life (Design Life) | Years | 25 | Can be capacity factor dependent |
| Technical Life (Operational Life) | Years | 40 | |

### 4.7.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 4-25 Cost estimates**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX – EPC cost** | | | |
| Relative cost | $ / kW | 1,900 | Net basis. Includes liquid fuel storage (30 hours) and associated infrastructure ~$8m. Capex premium on engine only component for 25% hydrogen by volume capability included. Relative cost does not include land and development costs. |
| Total EPC cost | $ | 397,290,000 | |
| ▪ Equipment cost | $ | 238,374,000 | 60% of EPC cost – typical. |
| ▪ Installation cost | $ | 158,916,000 | 40% of EPC cost – typical. |
| **Other costs** | | | |
| Cost of land and development | $ | 35,756,100 | Assuming 9% of CAPEX. |
| Fuel connection costs | $M | 21.2M +$1.6M/km | |
| **Start up Costs** | | | |
| Fast start up cost | $ | 225 | Fast start up cost based on fuel cost only |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / MW (Net) | 29,383 | Based on Aurecon internal database. Labour cost adjustment from 2023 included. |
| Variable O&M Cost | $ / MWh (Net) | 8.51 | Based on Aurecon internal database. CPI increase from 2023 to 2024 applied. |
| Total annual O&M Cost | $ | 10,038,567 | Annual average cost over the design life |

## 4.8 Ultra-supercritical coal fired power plants

### 4.8.1 Overview

Coal fired power plants are currently the dominant source of electricity generation in Australia, providing 57.6% of electricity generation for the NEM in 2021/2022[35]. In the NEM there are approximately 44 coal fired units installed across 15 power stations in QLD, NSW and VIC. The unit sizes range from 280 MW to 750 MW and use a range of coal types from low grade brown coal through to black coal.

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

[35] National Electricity Market FactSheet - 30 January 2024.pdf (aemo.com.au)

generator where the steam is expanded to produce electricity. This process is based on the thermodynamic Rankine cycle.

Coal fired power plants are typically classified as sub critical and super critical (more recently ultra-super critical 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 unit sizes.

### 4.8.2 Typical options

The coal fired power stations installed on the NEM utilise either subcritical or supercritical pulverised coal (PC) technology which is an established, well proven technology used for power generation throughout the world for many decades.

The latest supercritical coal fired units installed in Australia can produce supercritical steam conditions in the order of 24 MPa and 566°C and typically used with unit sizes above 400 MW. Internationally, more recent coal fired units have been installed with ever increasing steam temperature and pressure conditions. Current OEMs are proposing supercritical 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 however are currently being proposed by a number of OEMs.

### 4.8.3 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 limited focus on further coal fired development in Australia. More recently, alternative technologies have become more prevalent with a focus on adopting non-coal technologies for replacing lost capacity due to coal fired plant closures.

Internationally, particularly in Asia, there has been extensive development of new large coal fired power stations to provide for the growing demand for electricity (eg Van Phong 1 Coal Fired Power Plant, 2 x 660 MW in Vietnam has been commissioned in January 2024; Vung Ang II Thermal Power Plant, 2 x 665 MW in Vietnam is expected to be operational in 2024). These plants are now commonly being installed utilising supercritical 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. Investors are also not showing interest in coal fired power station developments.

In Australia the only coal fired development in progress is understood to be the Collinsville coal fired power station proposed by Shine Energy (3 x 315 MW totalling 1,000 MW). This project is in the definitive feasibility stage, scheduled for completion in 2024. The company website suggests construction commencement in 2025. In recent years there has been a lack of development activities relating to coal fired power plants. There are also reports regarding manufacturers stopping production of equipment for coal fired power plants. As such, it was difficult for Aurecon to obtain real data of projects costs and construction timeline. We used data from commercially available software packages for costs, performance and timeline.

### 4.8.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024, given the above discussion on typical options and current trends.

Table 4-26 Configuration and performance

| Item | Unit | AUSC without CCS | AUSC with CCS (90% capture efficiency) | AUSC with CCS (50% capture efficiency) | Comment |
|---|---|---|---|---|---|
| **Configuration** | | | | | |
| Technology | | AUSC | AUSC | AUSC | With natural draft cooling tower. |
| Carbon capture and storage | | No | Yes | Yes | 90% capture efficiency assumed.<br>SCR and FGD included with CCS option. |
| Make model | | Western OEM | Western OEM | Western OEM | Western includes Japanese or Korean OEMs |
| Unit size (nominal) | MW | 700 | 700 | 700 | ISO / nameplate rating. |
| Number of units | | 1 | 1 | 1 | |
| Steam Pressures<br>(Main / Reheat) | MPa | 33 / 6.1 | 33 / 6.1 | 33/6.1 | |
| Steam Temperatures<br>(Main / Reheat) | °C | 650 / 670 | 650 / 670 | 650/670 | |
| Condenser pressure | kPa abs | 6 | 6 | 6 | |
| **Performance** | | | | | |
| Total plant size (Gross) | MW | 700 | 700 | 700 | 25°C, 110 metres, 60%RH<br>Standard size offered by OEMs. Impact of unit size on NEM not assessed. |
| Auxiliary power consumption | % | 4.1% | 17.5% | 12.5% | Assumes steam driven Boiler Feed Pump, natural draft cooling tower. Excludes intermittent station loads. |
| Total plant size (Net) | MW | 671.3 | 577.3 | 612.3 | 25°C, 110 metres, 60%RH |
| Seasonal Rating – Summer (Net) | MW | 658.6 | 566.7 | 599.9 | 35°C, 110 metres, 60%RH |
| Seasonal Rating – Not Summer (Net) | MW | 673.8 | 581.7 | 616.3 | 15°C, 110 metres, 60%RH |
| Heat rate at minimum operation | (GJ/MWh) HHV Net | 10.172 (Down to 30%) | 11.644 (Down to 65%) | 10.108 (Down to 65%) | 25°C, 110 metres, 60%RH. |
| Heat rate at maximum operation | (GJ/MWh) HHV Net | 8.548 | 11.986 | 9.891 | 25°C, 110 metres, 60%RH. |
| Thermal Efficiency at MCR | %, HHV Net | 42.12% | 30.03% | 36.39% | 25°C, 110 metres, 60%RH. |
| **Annual Performance** | | | | | |
| Average Planned Maintenance | Days / yr. | 10.5 | 10.5 | 10.5 | Based on 14-day minor outage every 2 years and 28-day major outage every 4 years. |

| Item | Unit | AUSC without CCS | AUSC with CCS (90% capture efficiency) | AUSC with CCS (50% capture efficiency) | Comment |
|---|---|---|---|---|---|
| Equivalent forced outage rate | % | 4% | 4% | 4% | Indicative |
| Effective annual availability factor | % | 89 - 93% | 89 - 93% | 89 - 93% | Availability factor is based on forced and planned outages for plants burning Australian Black Coal. Availability factor varies with the age of the plant, its operating characteristics and type of coal being burnt. The range does not include rare catastrophic failure (e. g Callide C4 failure in 2021) |
| Annual generation | MWh / yr. | 5,468,946 | 4,703,147 | 4,988,285 | Provided for reference. |
| Annual degradation over design life - output | % | 0 | 0 | 0 | |
| Annual degradation over design life – heat rate | % | 0.2% | 0.2% | 0.2% | Assuming straight line degradation. |

**Table 4-27 Technical parameters and project timeline**

| Item | Unit | AUSC without CCS | AUSC with CCS (90% capture) | AUSC with CCS (50% capture) | Comment |
|---|---|---|---|---|---|
| **Technical parameters** | | | | | |
| Ramp Up Rate | MW/min | 20 | 20 | 20 | Based on 3%/min standard operation |
| Ramp Down Rate | MW/min | 20 | 20 | 20 | Based on 3%/min standard operation |
| Start-up time | Min | Cold: 444<br>Warm: 264<br>Hot: 60 | Cold: 444<br>Warm: 264<br>Hot: 60 | | Standard operation. |
| Min Stable Generation | % of installed capacity | 30% | 30% | 30% | Without oil support.<br>Gross basis |
| **Project timeline** | | | | | |
| Time for development | Years | 4-5 | 4-5 | 4-5 | includes pre/feasibility, design, approvals etc. (assuming no delay in development approvals) |
| First Year Assumed Commercially Viable for construction | Year | 2024 | 2024 | 2024 | |

| Item | Unit | AUSC without CCS | AUSC with CCS (90% capture) | AUSC with CCS (50% capture) | Comment |
|---|---|---|---|---|---|
| EPC programme for construction | Years | 4-5 | 4-5 | 4-5 | For NTP to COD. |
| Total Lead Time | Years | 2 | 2 | 2 | Time from NTP to steam turbine on site. |
| Construction time | Weeks | 104 | 104 | 104 | Time from steam turbine on site to COD. |
| Economic Life (Design Life) [a] | Years | 30 | 30 | 30 | |
| Technical Life (Operational Life) | Years | 50 | 50 | 50 | |

Notes:

a. This is typically how their economic life would be considered in isolation, however given current market conditions projects of this nature are not considered economically viable for the NEM as it stands, and that is why we are not seeing any other developments.

### 4.8.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 4-28 Cost estimates**

| Item | Unit | AUSC without CCS | AUSC with CCS (90%capture) | AUSC with CCS (50% capture) | Comment |
|---|---|---|---|---|---|
| **CAPEX – EPC cost** | | | | | |
| Relative cost | $ / kW | 5,031 | 10,219 | 8,211 | |
| Total EPC cost | $ | 3,377,310,000 | 5,899,518,000 | 5,027,478,000 | |
| ▪ Equipment cost | $ | 1,350,924,000 | 1,350,924,000 | 1,350,924,000 | 40% of EPC cost (without CCS) |
| ▪ Construction cost | $ | 2,026,386,000 | 2,026,386,000 | 2,026,386,000 | 60% of EPC cost (without CCS) |
| ▪ Carbon Capture cost | $ | N/A | 2,522,208,000 | 1,650,168,000 | Equipment and installation |
| **Other costs** | | | | | |
| Cost of land and development | $ | 675,462,000 | 1,179,903,000 | 1,005,495,000 | Assuming 20% of CAPEX. |
| Fuel connection costs | $/km | 2,279,000 | 2,279,000 | 2,279,000 | Assuming single track rail line fuel supply arrangement in the order of 50 to 100km in length. |
| $CO_2$ storage cost | $/t$CO_2$ | N/A | $12 - 25 | $12 - 25 | Based on Rubin, E.S., et al (2015)[36] and adjusted to match report basis |
| $CO_2$ transport | $/t$CO_2$/km | N/A | $0.1075 | $0.1075 | Based on Rubin, E.S., et al (2015) [19] and adjusted to match report basis |
| Start up costs | $ | 143,565 | 143,565 | 143,565 | Only fuel cost considered for a cold start up. |

[36] Rubin, E.S., et al., The cost of CO2 capture and storage. Int. J. Greenhouse Gas Control (2015), http://dx.doi.org/10.1016/j.ijggc.2015.05.018

| Item | Unit | AUSC without CCS | AUSC with CCS (90%capture) | AUSC with CCS (50% capture) | Comment |
|---|---|---|---|---|---|
| **OPEX – Annual** | | | | | |
| Fixed O&M Cost | $ / MW (Net) | 64,851 | 94,838 | 84,720 (Pro-rata basis from 0% and 90% capture) | AEMO costs and technical parameter review, 2023 (escalated) |
| Variable O&M Cost | $ / MWh (Net) | 4.68 | 8.85 | 7.43 (Pro-rata basis from 0% and 90% capture) | AEMO costs and technical parameter review, 2023 (escalated) |
| Total annual O&M Cost | $ | 69,145,416 | 96,379,999 | 88,937,014 | Annual average cost over the design life |

## 4.9 Open cycle gas turbine

### 4.9.1 Overview

Gas turbines are one of the most widely used power generation technologies today. The technology is well proven and is used in both open-cycle gas turbine (OCGT) and combined-cycle gas turbine (CCGT) configurations. Gas turbines are classified into two main categories - aero-derivatives and industrial turbines. Both find application 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 both natural gas and liquid fuel.

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

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

### 4.9.2 Typical options

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

- Better start-up time
- Operational flexibility ie quick ramp up and load change capability
- No penalties on O&M for number of starts.

Irrespective of the benefits of aero-gas turbines, industrial gas turbines have also been widely used in OCGT mode. Traditionally, E or D class machines are used in OCGT mode. Occasionally F or H class machines are used in OCGT applications. Examples where F class machines used in OCGT configuration in Australia include Mortlake Power Station (operational), Tallawarra B Power Station (in operation). and Kurri Kurri Power Station (under construction). Ultimately, the choice of gas turbine will depend on the many factors including the operating regime of the plant, size, and more importantly, life cycle cost.

### 4.9.3 Recent trends

#### General

The increased installation of renewables has created opportunities for capacity firming solutions. with gas-fired power generation options forming part of this solution. OCGT and reciprocating engines compete in this market.

#### Hydrogen

There is a trend for gas turbine developments are planned to move towards low emissions solutions with either blending of or firing completely on hydrogen. Blending with other renewable fuels such as biomethane is also being considered. Liquid fuel as backup supply is also planned for some projects. All new gas turbine projects are expected to include provision/capability for hydrogen blending and eventual conversion to hydrogen firing when hydrogen supply becomes more readily available.

Gas turbine OEMs are also looking at improving the hydrogen fuel capabilities of its offered models. Most gas turbines have the ability to operate with a percentage of hydrogen in the fuel mix.

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

The challenges with using hydrogen compared to say natural gas as a fuel for gas turbines include its lower heating value by volume requiring higher fuel flow for same energy input, combustion dynamics due to its high flame speed and temperature, and safety aspects such as flame visibility, small molecular size leading to increased risk of leaks, and wider flammability limit in air.

Gas turbine combustion systems either use a wet combustion system requiring a diluent such as water, or a dry system (Dry Low NOx or DLN/DLE) without the need for diluent to manage NOx gaseous emissions. The benefit of a DLN combustion system is that this avoids the need for water injection and provides for lower NOx emissions.

Single annular combustor (standard diffusion type), or single nozzle or multi nozzle combustors depending on whether aero-derivative or frame gas turbines such as those offered by GE are quoted as being able to handle up to 85% by volume and 90-100% by volume of hydrogen.

Dry Low NOx combustion systems (pre-mix type) such as those offered by GE are capable of operation up to 33% hydrogen by volume with natural gas (DLN1) for B and E class gas turbines, up to 35% on aero-derivative gas turbines, and 15% hydrogen by volume (DLN2.6+) with natural gas for larger F class gas turbines. Further developments with the DLN2.6e type combustion system and preliminary testing have indicated capability to operate up to 50% hydrogen by volume.

Depending on the percentage of hydrogen to be used the changes to the gas turbine for operation on hydrogen could be limited to a turbine controls update and new combustor fuel nozzles (if beyond current hydrogen capability installed), through to a new combustion system including new fuel accessory piping and valves, new fuel skid, and improved safety features such as enclosure and ventilation system modifications, and flame detection and gas detection.

Changes to gas turbine controls may impact gas turbine performance including both output and heat rate. Increasing the concentration of hydrogen may lead to significant increases in NOx emissions[37].

Siemens Roadmap to 100% hydrogen turbines set out its ambition for hydrogen capability in its gas turbine models to at least 20% by 2020 and 100% by 2030, with its smaller aero-derivative gas turbine units stated

[37] https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf

as capable of operation on 100% hydrogen with its wet combustion system (WLE)[38]. Siemens small industrial units are currently offered with a 30% hydrogen blending capability.

Kawasaki Heavy Industry (KHI) has undertaken successful combustor testing on its small gas turbine using 100% hydrogen with its standard diffusion flame combustor in Japan. Prototype testing of a hydrogen fuelled micro-mix DLN test burner producing low NOx emissions results has also been achieved[39].

Large F class gas turbines are quoted as being currently capable of between 5-30% hydrogen by volume as a blend with natural gas using a Dry Low NOx (DLN) combustion system depending on OEM. Hydrogen combustion can increase NOx emissions due to its higher flame temperature. Inclusion of a selective catalytic reactor (SCR) in the gas turbine exhaust for NOx emission control with hydrogen combustion may be required to meet local NOx emission limits depending on OEM, combustion system used (DLN or diffusion type), and hydrogen blending percentage.

Potential output reductions with higher blends of hydrogen are to be determined through consultation with the OEMs for aero-derivative and industrial heavy-duty gas turbines.

#### Recent projects

Some recent gas turbine power projects proposed for deployment on the NEM are summarised below:

- 400 MW Brigalow OCGT hydrogen ready peaking plant in Queensland, due to commence construction in 2025.
- Swanbank Clean Energy Hub development is considering a 140 MW OCGT hydrogen ready peaking plant in Queensland
- 300 MW Reeves Plains OCGT plant (South Australia). This project is currently in planning phase also with multiple aero-derivative units being considered
- 320 MW single unit F class OCGT plant in Tallawarra (NSW) now in operation, with a 5% hydrogen blending capability to be tested, and future possibility to convert the unit to combined-cycle mode
- 660 MW peaking OCGT plant near Kurri Kurri (NSW) comprising two F class gas turbine units with a 15-30% hydrogen blending capability proposed. This project is under construction phase.
- The South Australian Government has entered into an early contractor involvement agreement with consortium partners ATCO Australia and BOC for engineering design, procurement of critical equipment, and costings as part of the planned development of a hydrogen production, power generation, and storage facility located at Whyalla. The planned development includes a 250 MW electrolyser and a 200 MW hydrogen gas power generation plant using 100% hydrogen fuelled LM6000 gas turbines to be supplied by GE. The project is planned to commence operations in 2026. [40]

### 4.9.4 Selected hypothetical project

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

Current trends in Australia have included a larger gas turbine with a lower hydrogen blend percentage based on their current capability for hydrogen operation, or 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 electrolyser plant using renewable energy supply and blended with a natural gas pipeline supply to the site. In this case, OCGT plant

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[38] https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/
[39] https://www.kawasaki-gasturbine.de/files/Hydrogen_as_fuel_for_GT.pdf
[40] https://www.premier.sa.gov.au/media-releases/news-archive/global-energy-giant-ge-selected-as-preferred-supplier-for-hydrogen-jobs-plan

capacity would be based on hydrogen production from a suitable sized electrolyser plant and operated in peaking duty using hydrogen supply with storage to meet the hydrogen demand.

The following tables outline the technical parameters for the hypothetical projects (multiple small aero-derivative Dry Low NOx (DLN) gas turbines using 35% hydrogen blend with natural gas (based on current capability) and one large gas turbine using a 5-10% hydrogen blend) using natural gas, both projects with liquid fuel (eg diesel) back up. The hypothetical project has been selected based on what is envisaged as plausible projects for development in the NEM in 2024 given the above discussion on typical options and current trends.

**Table 4-29 Configuration and performance**

| Item | Unit | Small GT | Large GT | Comment |
|---|---|---|---|---|
| **Configuration** | | | | |
| Technology | | Aero-derivative | Industrial (F-Class) | |
| Make model | | LM2500 (GE) | GE 9F.03 | Small GTs − Typical model planned in Australian project, 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 with hydrogen blending.<br>Large GT − Smallest F-Class unit available |
| Unit size (nominal) | MW | 33.7 | 265 | % Output derate for 35% hydrogen to be confirmed with OEM for small GT. No derate considered.<br>ISO / nameplate rating, GT Pro.<br>Performance on natural gas |
| Number of units | | 6 | 1 | |
| **Performance (natural gas)** | | | | |
| Total plant size (Gross) | MW | 196.5 | 244.3 | 25°C, 110 metres, 60%RH<br>% Output derate for 35% hydrogen to be confirmed with OEM. No derate considered<br>Small GT includes inlet air cooling. |
| Auxiliary power consumption | % | 1.5% | 1.1% | Small GTs – Assumes fuel compression required<br>Large GT − Assumes no fuel compression required |
| Total plant size (Net) | MW | 193.55 | 241.7 | 25°C, 110 metres, 60%RH<br>% Output derate for 35% hydrogen to be confirmed with OEM. No derate considered |
| Seasonal Rating – Summer (Net) | MW | 188.06 | 226.4 | 35°C, 110 metres, 60%RH<br>% Output derate for 35% hydrogen to be confirmed with OEM. No derate considered |
| Seasonal Rating – Not Summer (Net) | MW | 198.96 | 258.2 | 15°C, 110 metres, 60%RH<br>% Output derate for 35% hydrogen to be confirmed with OEM. No derate considered |

| Item | Unit | Small GT | Large GT | Comment |
|---|---|---|---|---|
| Heat rate at minimum operation | (GJ/MWh) LHV Net | 13.072 | 14.735 | 25°C, 110 metres, 60%RH. Assuming a Minimum Stable Generation as stated below.<br>% heat rate derate for 35% hydrogen to be confirmed with OEM. No derate considered |
| Heat rate at maximum operation | (GJ/MWh) LHV Net | 9.373 | 9.766 | 25°C, 110 metres, 60%RH<br>% heat rate derate for 35% hydrogen to be confirmed with OEM. No derate considered |
| Thermal Efficiency at MCR | %, LHV Net | 38.4% | 36.86% | 25°C, 110 metres, 60%RH<br>% heat rate derate for 35% hydrogen to be confirmed with OEM. No derate considered |
| Hydrogen demand at maximum operation | kg/h (HHV) | 2,048 (@35% by vol at 100% load) | 276 (@ 5% by vol at 100% load) | |
| Heat rate at minimum operation | (GJ/MWh) HHV Net | 14.629 | 16.312 | |
| Heat rate at maximum operation | (GJ/MWh) HHV Net | 10.489 | 10.811 | |
| Thermal Efficiency at MCR | %, HHV Net | 34.3% | 33.30% | |
| **Annual Performance** | | | | |
| Average Planned Maintenance | Days / yr. | 5 | 5 | |
| Equivalent forced outage rate | % | 2% | 2% | |
| Effective annual capacity factor (year 0) | % | 20% | 20% | Average capacity factor for similar GTs on the NEM. Assumes hydrogen is available. |
| Annual generation | MWh / yr. | 339,100 | 423,502 | |
| Annual degradation over design life - output | % | 0.24% | 0.24% | Assuming straight line degradation. |
| Annual degradation over design life – heat rate | % | 0.16% | 0.16% | Assuming straight line degradation. |

Table 4-30 Technical parameters

| Item | Unit | Small GTs | Large GT | Comment |
|---|---|---|---|---|
| **Technical parameters** | | | | |
| Ramp Up Rate | MW/min | 87 | 22 | Station normal ramp rate under standard operation. Based on OEM data. |
| Ramp Down Rate | MW/min | 87 | 22 | Station normal ramp rate under standard operation. Based on OEM data. |
| Start-up time | Min | 10 | 30 | Standard normal operation. |
| Min Stable Generation | % of installed capacity | 50% | 50% | |

| Item | Unit | Small GTs | Large GT | Comment |
|---|---|---|---|---|
| **Project timeline** | | | | |
| Time for development | Years | 2 | 2 | Small GTs project – assumes hydrogen blend is within existing combustion system design capability<br>Large GT – assumes hydrogen blend is within existing combustion system design capability<br>includes pre/feasibility, design, approvals etc. |
| First Year Assumed Commercially Viable for construction | Year | 2024 | 2024 | |
| EPC programme | Years | 2.5+ | 2.5 | NTP to COD. |
| ▪ Total Lead Time | Years | 2+ | 2 | Time from NTP to gas turbine on site. |
| ▪ Construction time | Weeks | 78 | 58 | Time from gas turbine on site to COD. |
| Economic Life (Design Life) | Years | 25 | 25 | Can be capacity factor dependent |
| Technical Life (Operational Life) | Years | 40 | 40 | |

### 4.9.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 4-31 Cost estimate**

| Item | Unit | Small GT | Large GT | Comment |
|---|---|---|---|---|
| **CAPEX – EPC cost** | | | | |
| Relative cost | $ / kW | 2,193 | 1,189 | Net basis. Includes liquid fuel storage (30 hours) and associated infrastructure ~ $8-10m. Capex premium on gas turbine only component for hydrogen also included. Relative cost does not include land and development costs. Large GTs - cost variability between OEMs for F class units has been experienced recently. Cost range $1,150/kW-$1,550/kW |
| Total EPC cost | $ | 430,943,200 | 290,479,200 | |

| Item | Unit | Small GT | Large GT | Comment |
|---|---|---|---|---|
| Equipment cost | $ | 301,660,240 | 203,335,440 | 70% of EPC cost – typical. This does not include any SCR if NOx emissions limits are not met. No premium applied on large GT only component as assumed within existing capability for hydrogen blend percentage. Some minor costs for safety improvements, etc not included. This does not include any SCR if NOx emissions limits are not met. To be determined based on specific project and location. |
| Construction cost | $ | 129,282,960 | 87,143,760 | 30% of EPC cost – typical. |
| **Other costs** | | | | |
| Cost of land and development | $ | 38,784,888 | 26,143,128 | Assuming 9% of CAPEX. |
| Fuel connection costs | $M | $21.2M +$1.6M/km | $21.2M +$1.6M/km | Small GT plant assumed hydrogen supply available. Blend skid included.<br>Large gas turbine plant - Gas Transport (ie pipes/lines) – assumes hydrogen blended in gas network up to 10% hydrogen by volume. No line pack considered for fuel storage. Otherwise blend skid required (not included) |
| Gas compressors | $ | Required | Not required | Assume hydrogen storage pressure sufficient, or gas pipeline supply pressure sufficient.<br>Small GT – Gas compression may be required (not included)<br>Large GT - Let down station may be required (not included) |
| Gas storage | | Excluded | Fixed: $0.015 - $0.025 /GJ/Day<br><br>Variable (injection): $0.014 - $0.093 /GJ<br><br>Variable (withdraw): $0.041 - $0.093 /GJ | Gas storage refers to underground storage facility in a depleted natural gas field.<br><br>Costs based on published prices for Iona underground gas facility. |
| **Startup Costs** | | | | |
| Fast start up cost | $ | 1,200 | 27,000 | Based on fuel cost only for a fast start up. |
| First Year Assumed Commercially Viable for construction | | 2024 | 2024 | For % hydrogen capability stated above. |

| Item | Unit | Small GT | Large GT | Comment |
|---|---|---|---|---|
| **OPEX – Annual (excluding fuel)** | | | | |
| Fixed O&M Cost | $ / MW (Net) | 17,368 | 14,066 | Based on Aurecon internal database. Labour cost adjustment from 2023 included. |
| Variable O&M Cost | $ / MWh (Net) | 16.1 | 8.1 | Based on Aurecon internal database. Impact of hydrogen blend combustion on maintenance schedule not considered. OEM to be consulted. Assumes less than 1 start per day. Additional starts may incur higher maintenance costs depending on OEM maintenance schedule calculation considering starts. |
| Total annual O&M Cost | $ | 8,943,477 | 6,896,814 | Annual average cost over the design life |

## 4.10 Combined cycle gas turbine

### 4.10.1 Overview

Over time, combined-cycle gas turbines (CCGT) became the technology of choice for gas-fired base load and intermediate load power generation. Typically, they consist of 1 or more gas turbine generator sets (gas turbines plus the electric generator), dedicated heat recovery steam generators (HRSG), and a steam turbine generator set (steam turbine plus the electric generator).

Advancements in gas turbine technology have led to significant increase in CCGT efficiencies, with some gas CCGT plants, namely those with H-class gas turbines, offering efficiencies of above 60%.

### 4.10.2 Typical options

Both aero and industrial gas turbines are widely used for CCGT applications. However, traditionally industrial gas turbines are preferred. Popular CCGT configuration options when deployed include:

- 1-on-1 (1 x 1) option consisting of 1 gas turbine generator set, a dedicated HRSG, and a steam turbine generator set
- 2-on-1 (2 x 1) option consisting of 2 gas turbine generator sets, 2 dedicated HRSGs, and a steam turbine generator set.

Other options have also been used eg 3 x 1 configuration, but they are not a typical offering.

### 4.10.3 Recent trends

In Australia, there has not been a CCGT plant constructed in the NEM region since the commissioning of Tallawarra A in 2009. Recent CCGT projects constructed in Australia include:

- South Hedland Power Plant – 2 x 1 CCGT with LM 6000 PF SPRINT.

Whilst there is not much current activity in the development of CCGT plants in Australia due to current market needs in the NEM and high gas prices, the following CCGT plants under future development in Australia include:

- 660 MW CCGT plant at Port Kembla with intermediate duty using single H class gas turbine, planned to be operational in 2024 / 2025 with open cycle operation [41]
- Tallawarra B CCGT plant from conversion using single F class OCGT plant.

Any combined cycle gas turbine plant developed for connection to the NEM would need to be designed for operational flexibility and turndown for flexible dispatch due to increased variable renewable generation on the NEM.

The choice of gas turbine class would be influenced by the project size. With very little recent CCGT activities in NEM, selecting the plant configuration or gas turbine class is difficult. However, if a CCGT is to be developed in Australia / the NEM, given the prevalent high gas price, high efficiency gas turbines (F or H/J class) would probably be the preferred gas turbine class, depending on the project size (MW), cost, etc. Based on this assessment, Aurecon has selected a CCGT with an F class gas turbine as typical, as a H class gas turbine, depending on grid connection location, unit size may be too large based on current NEM market requirements. F class gas turbines range from 265 – 450 MW in open-cycle, and from 400 – 685 MW in 1+1 combined-cycle configuration (at ISO conditions). H/J Class gas turbines however range from 445 – 595 MW in open-cycle, and from 650 – 880 MW in 1+1 combined-cycle configuration (at ISO conditions). Open cycle operation may need to be considered for H class technology as is proposed for Port Kemba Power Station due to development staging for combined cycle depending on grid connection location and ultimate combined cycle block size.

Current CCGT developments in Australia consider open cycle gas turbine units with capability for operation on hydrogen blended fuel, some with future provision to convert to CCGT, given latest trends in other firming and storage options in the market to accommodate the increase in renewable energy on the NEM.

### 4.10.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024, given the above discussion on typical options and current trends.

**Table 4-32 Configuration and performance**

| Item | Unit | CCGT without CCS | CCGT with CCS (90% capture) | CCGT with CCS (50% capture) | Comment |
|---|---|---|---|---|---|
| **Configuration** | | | | | |
| Technology | | CCGT | CCGT | CCGT | With mechanical draft cooling tower. |
| Carbon capture and storage | | No | Yes | Yes | |
| Make model | | GE 9F.03 | GE 9F.03 | GE 9F.03 | Smallest model available selected. |
| Unit size (nominal) | MW | 409 | | | ISO / nameplate rating. |
| Number of units | | 1 GT + 1 ST | 1 GT + 1 ST | 1 GT + 1 ST | HP pressure – 165 bar<br>HP temperature – 582°C<br>Reheat temperature – 567°C |
| **Performance (natural gas)** | | | | | |
| Total plant size (Gross) | MW | 380 | 351.5 | 364.7 | 25°C, 110 metres, 60%RH |
| Auxiliary power consumption | % | 2.5% | 9.2% | 7.3% | |

[41] https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=PDA-301275

| Item | Unit | CCGT without CCS | CCGT with CCS (90% capture) | CCGT with CCS (50% capture) | Comment |
|---|---|---|---|---|---|
| Total plant size (Net) | MW | 371 | 319.3 | 338.1 | 25°C, 110 metres, 60%RH |
| Seasonal Rating – Summer (Net) | MW | 348 | 301.5 | 318.8 | 35°C, 110 metres, 60%RH |
| Seasonal Rating – Not Summer (Net) | MW | 389 | 334.5 | 354.0 | 15°C, 110 metres, 60%RH |
| Heat rate at minimum operation | (GJ/MWh) LHV Net | 7.472 | 8.290 | 7.764 | 25°C, 110 metres, 60%RH. Assuming a Minimum Stable Generation of 46% on gaseous fuel. |
| Heat rate at maximum operation | (GJ/MWh) LHV Net | 6.385 | 7.415 | 7.004 | |
| Thermal Efficiency at MCR | %, LHV Net | 56.4% | 48.5% | 51.4% | |
| Heat rate at minimum operation | (GJ/MWh) HHV Net | 8.271 | 9.177 | 8.595 | Assuming LHV to HHV conversion of 1.107. |
| Heat rate at maximum operation | (GJ/MWh) HHV Net | 7.068 | 8.208 | 7.753 | Assuming LHV to HHV conversion of 1.107. |
| Thermal Efficiency at MCR | %, HHV Net | 50.9% | 43.9% | 46.4% | Assuming LHV to HHV conversion of 1.107. |
| **Annual Performance** | | | | | |
| Average Planned Maintenance | Days / yr. | 12.8 | 12.8 | 12.8 | Based on 3.5% average planned outage rate over a full maintenance cycle. |
| Equivalent forced outage rate | % | 3.5% | 3.5% | 3.5% | |
| Effective annual capacity factor | % | 60% | 60% | 60% | |
| Annual generation | MWh / yr. | 1,949,135 | 1,678,240 | 1,777,054 | Provided for reference. |
| Annual degradation over design life - output | % | 0.20% | 0.20% | 0.20% | Assuming straight line degradation. |
| Annual degradation over design life – heat rate | % | 0.12% | 0.12% | 0.12% | Assuming straight line degradation. |

Table 4-33 Technical parameters and project timeline

| Item | Unit | CCGT without CCS | CCGT with CCS (90% capture) | CCGT with CCS (50% capture) | Comment |
|---|---|---|---|---|---|
| **Technical parameters** | | | | | |
| Ramp Up Rate | MW/min | 22 | 22 | 22 | Standard operation. |
| Ramp Down Rate | MW/min | 22 | 22 | 22 | Standard operation. |

| Item | Unit | CCGT without CCS | CCGT with CCS (90% capture) | CCGT with CCS (50% capture) | Comment |
|---|---|---|---|---|---|
| Start-up time | Min | Cold: 145<br>Warm: 115<br>Hot: 30 | Cold: 145<br>Warm: 115<br>Hot: 30 | Cold: 145<br>Warm: 115<br>Hot: 30 | Standard operation. |
| Min Stable Generation | % of installed capacity | 46% | 46% | 46% | Differs between GT models. Equates to 35% GT load. |
| **Project timeline** | | | | | |
| Time for development | Years | 2-3 | 3 | 3 | includes pre/feasibility, design, approvals etc. |
| First Year Assumed Commercially Viable for construction | Year | 2024 | 2024 | 2024 | |
| EPC programme | Years | 3 | 3-3.5 | 3-3.5 | For NTP to COD. |
| ▪ Total Lead Time | Years | 1.5-2 | 1.5-2 | 1.5-2 | Time from NTP to long lead items on site. |
| ▪ Construction time | Weeks | 78 | 104+ | 104+ | Time from gas turbine / steam turbine on site to COD. |
| Economic Life (Design Life) | Years | 25 | 25 | 25 | |
| Technical Life (Operational Life) | Years | 40 | 40 | 40 | |

### 4.10.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 4-34 Cost estimates**

| Item | Unit | CCGT without CCS | CCGT with CCS (90% capture) | CCGT with CCS (50% capture) | Comment |
|---|---|---|---|---|---|
| **CAPEX – EPC cost** | | | | | |
| Relative cost | $ / kW | 2,360 | 5,576 | 4,756 | Net basis, Increase basis[42]. Relative cost does not include land and development costs. Includes premium allowance for hydrogen ready GT/HRSG. |
| Total EPC cost | $ | 835,728,075 | 1,699,623,133 | 1,534,788,803 | |
| ▪ Equipment cost | $ | 585,009,652 | 585,009,652 | 585,009,652 | 70% of EPC cost (without CCS) |
| ▪ Construction cost | $ | 250,718,422 | 250,718,422 | 250,718,422 | 30% of EPC cost (without CCS) |
| ▪ Carbon Capture cost | $ | - | 863,895,058 | 699,060,729 | Equipment and installation |

[42] Thermoflow software increase in CCGT plant EPC price of in its latest release version in 2024.

| Item | Unit | CCGT without CCS | CCGT with CCS (90% capture) | CCGT with CCS (50% capture) | Comment |
|---|---|---|---|---|---|
| **Other costs** | | | | | |
| Cost of land and development | | 75,215,527 | 152,966,082 | 138,130,992 | Assuming 9% of CAPEX. |
| Fuel connection costs (CAPEX) | $M | $21.2M +$1.6M/km | $21.2M +$1.6M/km | $21.2M +$1.6M/km | Excludes any line pack for storage |
| Gas compressors | | Not required | Not required | Not required | |
| Gas storage[43] | | Fixed: $0.015 - $0.025 /GJ/Day<br>Variable (injection): $0.014 - $0.093 /GJ<br>Variable (withdraw): $0.041 - $0.093 /GJ | | | Gas storage refers to underground storage facility in a depleted natural gas field.<br>Costs based on published prises for Iona underground gas facility. |
| $CO_2$ storage cost | $/t$CO_2$ | N/A | $12 - 25 | $12 - 25 | Based on Rubin, E.S., et al (2015)[44] and adjusted to match report basis |
| $CO_2$ transport | $/t$CO_2$/km | N/A | $0.1075 | $0.1075 | Based on Rubin, E.S., et al (2015)[17] and adjusted to match report basis |
| **Startup Costs** | | | | | |
| Fast start up cost | $ | 163,000 | 163,000 | 163,000 | Based on fuel cost only for a fast start up |
| **OPEX – Annual** | | | | | |
| Fixed O&M Cost | $ / MW (Net) | 15,028 | 22,542 | 19,955 | Based on Aurecon internal database. Labour cost adjustment from 2023 included. |
| Variable O&M Cost | $ / MWh (Net) | 4.1 | 8.0 | 6.7 | Based on Aurecon internal database. CPI increase from 2023 to 2024 applied. |
| Total annual O&M Cost | $ | 13,560,540 | 20,590,022 | 18,688,586 | Annual average cost over the design life |

## 4.11 Bioenergy

### 4.11.1 General

Bioenergy considered in this section of the 2024 report includes:

- Biogas digesters
- Biomass generators using wood chips, pellets or prepared biomass feed
- Biodiesel production using pathways suitable for Australian feedstocks with demonstrated technologies
- Waste to Energy plant using pathways suitable for Australian feedstocks with demonstrated technologies

[43] ACCC (2020), "Gas inquiry 2017–2025 Interim report", www.ACCC.gov.au
[44] Rubin, E.S., et al., The cost of CO2 capture and storage. Int. J. Greenhouse Gas Control (2015), http://dx.doi.org/10.1016/j.ijggc.2015.05.018

The past 12 months have seen considerable advances in the acceptance, adaption and integration of bioenergy systems into circular economy applications. The Australian Energy Update 2024 provides a breakdown of the relative contribution of bioenergy systems across the renewable energy platform.

### 4.11.2 Bioenergy's contribution to Australia's energy mix

Renewable energy consumption comprises mainly biomass, hydro, wind and solar energy.

In 2022–23, renewable energy consumption rose 8 per cent, due to strong growth in solar and wind (Table 4-35).

Renewable energy use includes energy used for electricity generation as well as various direct uses of renewable fuels such as firewood for residential heating, bagasse (sugar cane waste) combustion for heat in manufacturing, and solar hot water.

The following Table provides a summary of the Australian renewable energy consumption by fuel type, energy units.

**Table 4-35 Australian renewable energy consumption, by fuel type, energy units [a]**

| Renewable Energy Type [b] | 2015-16 | 2016-17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2022-23 |
|---|---|---|---|---|---|---|---|---|
| | PJ | PJ | PJ | PJ | PJ | PJ | PJ | PJ |
| **Biomass** | **196.1** | **203.4** | **189.6** | **179.6** | **169.3** | **173.6** | **171.0** | **177.2** |
| ▪ wood and other [c] | 93.9 | 93.1 | 89.4 | 88.2 | 85.5 | 85.7 | 86.6 | 89.5 |
| ▪ bagasse | 102.2 | 110.3 | 100.2 | 91.3 | 83.8 | 88.0 | 84.4 | 92.3 |
| **Municipal and industrial waste** | **2.5** | **4.8** | **4.8** | **4.6** | **4.0** | **4.6** | **4.7** | **4.6** |
| **Biogas** | **15.8** | **15.3** | **16.1** | **16.3** | **16.7** | **17.6** | **18.5** | **18.0** |
| ▪ landfill gas | 14.7 | 11.8 | 12.2 | 12.3 | 12.6 | 13.2 | 13.9 | 13.5 |
| ▪ other biogas | 1.1 | 3.6 | 3.9 | 4.0 | 4.0 | 4.4 | 4.6 | 4.6 |
| **Biofuels** | **7.2** | **6.8** | **7.2** | **7.4** | **6.6** | **6.3** | **6.1** | **6.2** |
| ▪ ethanol | 5.3 | 5.5 | 6.0 | 6.1 | 5.4 | 4.9 | 4.8 | 5.0 |
| ▪ biodiesel | 0.2 | 0.2 | 0.0 | 0.0 | 0.1 | 0.1 | 0.2 | 0.03 |
| ▪ other liquid biofuels | 1.7 | 1.1 | 1.1 | 1.3 | 1.1 | 1.2 | 1.2 | 1.2 |
| **Wind power** | **43.9** | **45.3** | **54.6** | **63.8** | **73.4** | **88.3** | **104.8** | **113.0** |
| **Hydro power** | **55.1** | **58.6** | **57.7** | **57.5** | **54.5** | **54.7** | **61.2** | **60.0** |
| **Solar PV** | **24.6** | **29.1** | **35.7** | **53.5** | **75.7** | **99.8** | **124.9** | **151.1** |
| **Solar hot water** | **14.9** | **15.8** | **16.7** | **17.6** | **18.5** | **19.7** | **21.3** | **23.5** |
| **Total** | **360.2** | **379.1** | **382.5** | **400.2** | **418.8** | **464.6** | **512.5** | **553.6** |

Notes:

a. Ref: Australian Government Department of Climate Change, Energy, the Environment and Water – Australian Energy Update August 2024

b. Renewable energy consumption includes inputs to electricity generation as well as direct use of renewable energy

c. Includes wood waste, charcoal, sulphite lyes and other biomass.

Australia's energy consumption increased in 2022–23, for the first time in four years. Energy use in electricity supply decreased as coal generation continues to fall. With the rebound in activity post COVID-19 restrictions, transport and commercial energy use increased.

The 2022–23 financial year set a record for Australia's clean energy supply. Renewable generation increased 11 per cent, accounting for 34 per cent of Australia's electricity generation. Solar electricity generation grew 21 per cent in the 2022–23 year and is 11 times higher than a decade ago.

Renewable energy accounted for 9 per cent of Australian energy consumption in 2022–23. Renewable energy consumption comprises biomass, hydro, wind and solar energy.

In 2022–23, renewable energy consumption rose 8 per cent, with strong growth in solar and wind.

Renewable energy use includes energy used for electricity generation as well as various direct uses of renewable fuels such as firewood for residential heating, bagasse (sugar cane waste) combustion for heat in manufacturing, and solar hot water.

Consumption of bagasse, the remnant sugar cane pulp left after crushing, grew by 9.3 per cent in 2022–23 due to a larger sugar crop in the 2022 season. Bagasse has long been a significant source of renewable energy in Australia for direct heat and for electricity production, comprising 16.7 per cent of total renewable energy use in 2022–23.

Solid municipal and industrial waste can be used to generate electricity or direct heat and provided 4.6 petajoules of energy in 2022–23.

Biogas from landfill, sewerage and other sources provided a further 18 petajoules of energy in 2022–23, most used for electricity generation, although some injection of biomethane into gas pipelines is occurring.

Renewable energy used for electricity generation increased 10 per cent while direct use of renewables increased 5 per cent in 2022–23. This continues the long-term trend, where most growth in renewable energy activity is for electricity generation rather than direct use.

In 2022–23 electricity supply accounted for 65 per cent of total Australian renewable energy use, up from 40 per cent a decade ago.

Renewables production in 2022 increased by 8.1 per cent to 553.5 PJ, due to the continuing expansion of solar PV, solar hot water and wind electricity production, while hydro generation fell by 2% due to water levels and competition to other energy types.

### 4.11.3 Bioenergy circular economy systems

The following figure provides an infographic highlighting the circular economy nature for the bioenergy systems of biogas, biomass generators, biofuels and waste to energy.

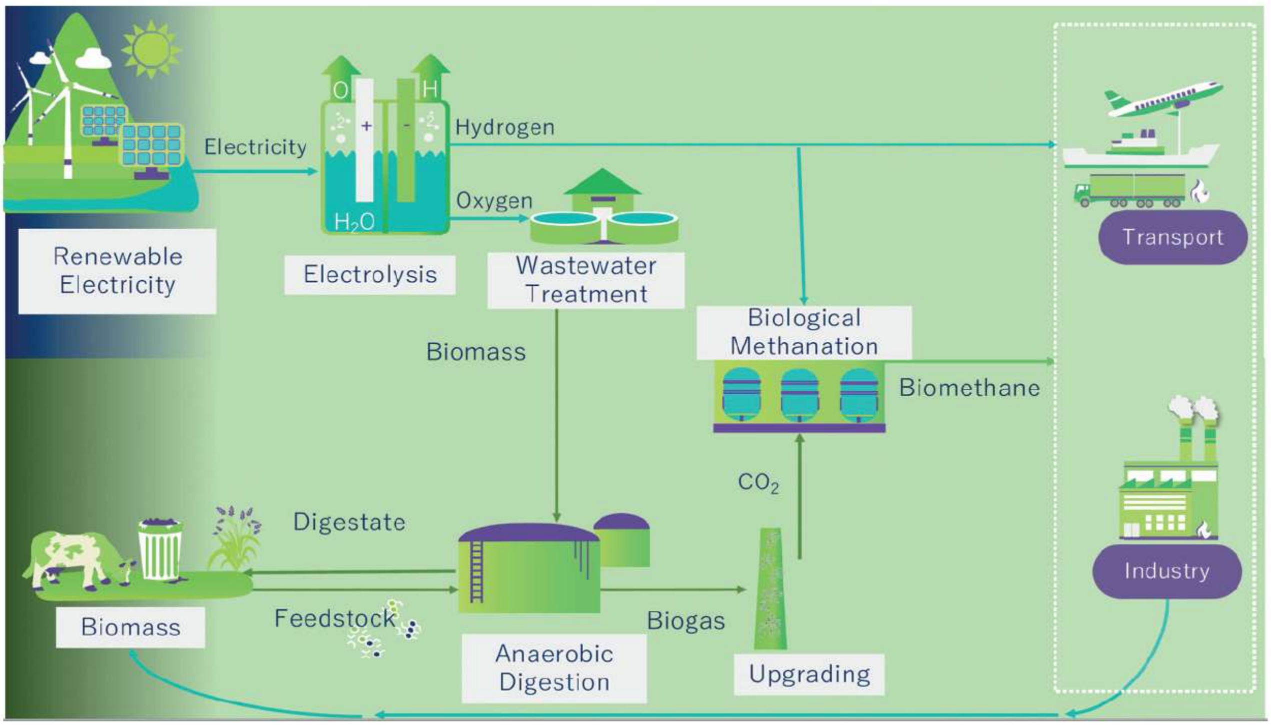



**Figure 4-2 Bioenergy systems utilizing renewable feedstocks**

(Ref IEA Bioenergy: Task 37 November 2021 - Renewable Gas – discussion on the state of the industry and its future in a decarbonised world)

## 4.11.4 Emerging sustainability issues

The current focus on ESG and SDGs has seen some countries not supporting the use or production of energy crops for bioenergy purposes. The use of limited biomass resources is debated in the context of competing interests of other utilisation pathways (such as for liquid fuels or materials production). Other concerns include for: land use change; general agricultural and environmental issues; and the food versus fuel debate. Substrates which are accepted as sustainable include for wastewater sewage sludge, varieties of wet organic waste, and agricultural residues such as manure where AD can provide a form of waste treatment. Typically, energy crops (including catch crops) give potential to scale up production, add significantly to the methane yield as compared to slurries and as a result, in some countries, enjoy widespread use in co-digestion with other substrates.

Available bioenergy potential and related biogas potential in specific regions can be estimated with consideration of:

- Geographical specific resource, spatial distribution and gas potential of substrate types
- Restrictions on access to substrates whether technical, sustainable, economic or legislative
- Public acceptance of substrate utilisation and technologies
- Competing substrate utilisation pathways (material use, production of other energy carriers such as liquid biofuels).

For example, Biogas systems can protect our air, water and soil while recycling organic material to produce renewable energy and soil products. In cities, biogas systems recycle food scraps and wastewater sludge, reducing municipal costs and improving air emissions. In rural areas, biogas systems make agriculture more sustainable and create additional revenue streams for farmers. Since biogas systems prevent greenhouse gases, like methane, from entering the atmosphere, all biogas systems can make our air cleaner to breathe and combat climate change, displacing fossil fuels. At the same time, biogas systems produce soil products that can recycle nutrients, contributing to healthier soils and creating opportunities to eliminate nutrient runoff that pollutes waterways.

## 4.11.5 Biogas systems

### Biogas, biomethane and syngas

Biogas is a gas mixture containing methane (CH4) and CO, along with water vapour and other trace gases. The composition of CH4 in biogas is typically in the range of 45 to 75% whilst $CO_2$ comprises 30 to 50%. This variation means that the energy content of biogas can vary; the lower heating value (LHV) is between 16 MJ/$m^3$ and 28 MJ/m3. Biogas is generated from the degradation of wet organic biomass achieved by a large variety of microorganisms in the absence of oxygen in an anaerobic digestion (AD) process. Typical biomass sources for biogas production include for agricultural residues, energy crops, wastewater sewage sludge, the organic fraction of municipal solid waste and seaweeds. Biogas can be used directly in a combined heat and power (CHP) unit for the production of electricity and heat.

Biogas and biomethane are different products with different applications, but they both originate from a range of organic feedstocks whose potential is underutilised today. The production and use of these gases embody the idea of a more circular economy, bringing benefits from reduced emissions, improved waste management and greater resource efficiency. Biogas and biomethane also provide a way to integrate rural communities and industries into the transformation of the energy sector.

Solid biomass can also undergo gasification at high-temperatures (between 700-800°C) and high pressure in a low-oxygen environment, whereby it is thermally decomposed into a gaseous product (syngas) and a solid product (biochar). Syngas can subsequently be combusted for heat and power production or converted into various alternative fuels such as bio-Synthetic Natural Gas (bioSNG) via a methanation step. BioSNG, which may also be termed biomethane as it is produced from biomass, is a product comparable to natural gas which can be injected into the existing gas grid and used in known gas applications.

## History in Australia

Most biogas production in Australia is associated with municipal Wastewater Treatment Plants (WWTP), process wastewater from red meat processing and rendering plants, waste manure from piggeries, manure slurry from dairies and poultry and landfill gas power units.

## Typical biogas system options

Many heritage agricultural industries have established value chains, logistics and processing systems that provide a solid platform to develop bio products. Biogas and its upgraded form, biomethane, are being increasingly recognised, not only as a scalable and flexible source of renewable gas, but also as an enabler of local and sustainable development. The environmental performance of these green gases is very promising, as they can reduce CO2 emissions below zero levels and contribute to lower methane emissions. Biogas and biomethane are important enablers of the EU Green deal, but they also form the cornerstone of a circular bioeconomy. They are produced from organic residues, which helps to reduce industrial and municipal waste. In addition, they support the development of the agroecology by using sustainable farming feedstocks, restoring our soils with organic carbon or prompting the use of digestate as organic fertiliser.

Biogas, through anaerobic digestion (AD) provides another platform to extract more value out of internal coproduct and waste streams and external feedstocks from the region. The biogas systems in Australia have generally been installed to match the size of the feedstock and range from 0.25 MW to 2 MW of generation capacity. Some recent projects like at the Kilcoy Pastoral Company have installed a total of 4 MW of combined heat and power (CHP) generating units, via 2 x 1.5 MW CHP and 1 x 1.5 MW CHP engines. With a turndown ratio nominally at 50%, Owners will often elect to install multiple smaller units if the biogas production is intermittent and there is insufficient storage to run the biogas power station constantly over a 24-hour period, or across the year.

## Emerging biogas systems

Biogas plants play an important role in decarbonisation. Bacteria in these plants break down biomass in the absence of oxygen to form biogas which, on average, comprises up to 60 percent methane and more than 40 percent $CO_2$. While the biogas is used to generate electricity and heat in combined heat and power units or can be upgraded to natural gas quality and fed into the natural gas network, the $CO_2$ has not been utilized to date. Emerging systems are converting the $CO_2$ into methane using green hydrogen. This enables a biogas facility to convert 'waste off-spec' methane into additional methane, thus drastically increasing the methane yield from biogas plants. The underlying chemical reaction has been discovered more than hundred years ago, but to date it has not been used for direct upgrading of biogas. In the scope of the energy transition process, however, pathways for the utilization of $CO_2$ are coming into focus.

## Compressed natural gas refuelling stations

The upgrading of biogas into renewable natural gas (RNG) quality, then compressing to increase energy density in a compressed natural gas (CNG) is becoming more widespread globally. The CNG can be utilised as a transport fuel in the transition from diesel to blended biomethane gas fuels. Going forward, the mix of biomethane is being increased to suit equivalent natural gas powered trucks, making further inroads to cleaner transport.

Many global major car manufacturers produce CNG vehicles ranging from passenger vehicles to vans to buses to heavy duty trucks. The availability of CNG vehicles in Australia is currently limited to light duty and heavy duty vehicles, including buses. Most CNG vehicles in Australia belong to fleets that have their own private refuelling stations. There are a small number of publicly accessible CNG refuelling stations across the country.

Though Australia does not have a broad public CNG refuelling network at the moment, this does not exclude fleet operators from using CNG in their fleets. The most viable operations for CNG in Australia are currently either back-to-base arrangements, where vehicles return to the same depot each day, such as bus fleets, or point-to-point operations between bases. In these situations, the fleet operator may own or lease CNG refuelling equipment or contract a specialist fuel supplier to supply fuel to the vehicles. Your local gas network operator can help identify how the gas network can be utilised for fleet operators.

An Australian example is Shepparton based linen provider, Gouge Linen, who operates a fleet of 19 trucks, servicing the hospitality and health care industry in regional Victoria. Of the fleet, four of the trucks, Isuzu FSR's and one Hiace van operate on CNG. Company Director, Phil Priestly, says the CNG vehicles were first introduced to the fleet in 2009 and have proved reliable performers since. The trucks currently cover a total of 300,000 kms a year on CNG, while the van is just used for local errands. The vehicles are refuelled on-site, using fast-fill equipment that can refuel all five vehicles simultaneously. The Figure below shows the Gouge Linen private CNG refuelling stations:


**Figure 4-3 Gouge linen CNG Isuzu at private CNG refuelling stations**

## Integration with other forms of renewable energy

Through the use of biodigesters, agricultural manure can be converted into renewable natural gas (RNG) and the remaining remnants into valuable materials including fertilizer, potable water and $CO_2$.

Hybrid facilities can be strategically designed to run off multiple forms of renewable energy. An integrated renewable energy facility can aggregate distributed energy in the form of a microgrid that is powered by solar panels and battery storage, or in refining RNG for use as fuel in gas engines or vehicles. The more layers of renewable energy that are integrated into the creation of RNG, the greater the impact on reducing greenhouse gases. For example, if RNG is transported using electric vehicle fleets powered by renewable electricity, that would further reduce the negative impact on the environment.

This self-sustaining network benefits the farmers who can manage their animal waste, prevent the release of methane into the atmosphere and receive the resulting nutrient-dense materials for their fertilizer and bedding. It benefits the county and community by reducing the phosphorous runoff to nearby streams and lakes. And it benefits the renewable transportation fuel industry with the RNG created by the extracted methane.

## Recent trends

Whilst a large body of information exists for the installation of biogas plants across various Australian industries, there is always a need to ground truth proposed value chains by utilising where possible existing ‘tried and proven’ technologies from established suppliers in the biogas industry.

The scale of the biogas plant is typically limited by the amount and type of feedstock available and the ability to establish continuous logistics supply of feedstock to match continuous production and steady utilisation of biogas to match the local system demand. As a result of feedstock constraints, the majority of biogas generation projects have power station capacities less than 2 MW. Feedstock assessments are required to mitigate risks in maintaining a continuous supply across the year for seasonal feedstocks and waste streams, according to supply contractual arrangements. Any assumptions on future feedstocks availability will need to include market negotiations of offtake agreements, quality specifications and logistics contracts.

On-site conversion of organic waste into biogas to satisfy consumer energy demand has the potential to realize energy equality and mitigate climate change reliably. However, existing methods ignore either real-time full supply or methane escape when supply and demand are mismatched.

Bio precinct concepts have been discussed in recent times across all states. These aim to shore up the electricity generation by considering a combination of solar/battery/ biogas hybrid generation, rather than just supplying organic feedstocks to a large AD plant and generating power from biogas. These hybrid options also enable the sale of electricity, heat and steam to behind the meter customers in the precinct. Hybrid energy generation options can also optimise collocated biorefineries to operate for 24 hour per day operations.

## Feedstocks

A wide variety of feedstocks can be used to produce biogas. These are usually grouped into four broad feedstock categories: crop residues; animal manure; the organic fraction of MSW, including industrial waste; and wastewater sludge.

Specific energy crops, (ie low-cost and low-maintenance crops grown solely for energy production rather than food), have also played an important part in the rise of biogas production in some parts of the world. However, they have also generated a vigorous debate about potential land-use impacts, so they attract different arguments for sustainable supply potential.

Using waste and residues as feedstocks avoids the land-use issues associated with energy crops. Energy crops also require fertiliser (typically produced from fossil fuels), which needs to be taken into account when assessing the life-cycle emissions from different biogas production pathways.Using waste and residues as feedstocks can capture methane that could otherwise escape to the atmosphere as they decompose.

MSW can either feed a biodigester or be disposed in landfill to produce landfill gas, so has a double benefit for CO2 avoidance.

Typically, transport logistics and associated costs will make or break the business case of utilising external feedstocks. The ability to purchase the feedstock at the ‘right’ price and have efficient logistics and materials handling is crucial to creating a viable business case for the AD unit. Harvesting, loading and storage methods of feedstocks are critical for achieving efficient logistics and lowering AD unit input costs. The ability to minimise double handling of feedstock streams is critical to contain logistics costs to reasonable levels. Where the feedstock is already collected as a liquid, or as a solid onto a conveyor, storage bin or storage pad, the ability to ‘just-in-time’ collect and deliver the feedstock will save the producer storage, waste management and disposal costs.

Various feedstock pre-treatment methods are utilised to maximise biogas yields in AD processes. Pre-treatment increases the yield of biogas from feedstocks in anaerobic digestion. Substrates composed of high-density fibre, or not readily biodegradable matter, usually require pre-treatment. Technique used for pre-treatment depends on the type of substrate and utilises a wide degree of methods including thermal, chemical, physical/mechanical, ultrasound, microwave, biological and metal addition methods.

Biogas can be produced from a wide range of feedstocks. AD efficiency relates to biogas yield, which vary across feedstock types and regions. The energy value in the feed will also relate to its input cost.

The alternative route to biomethane production – gasification – opens up the possibility of using additional sources of solid biomass feedstock: biomass trash from primary producers, forestry residues and wood processing residues.

## Current Australian and New Zealand example projects

### Malabar biomethane injection project

Lead Organisation Jemena Limited, Location Malabar, New South Wales.

Started November 2020, and fully operational by June 2023.

$16m Total project cost.

Jemena's Malabar Biomethane Injection Plant is already injecting into the NSW gas network and demonstrating the compatibility of biomethane with existing infrastructure. While renewable electricity generation is still intermittent and not yet able to meet 'on-demand needs, renewable gas like biomethane can provide an additional and complementary renewable energy solution.

Entirely compatible with existing gas pipes, appliances and industrial equipment, biomethane offers a pathway to reduce emissions without the need for extensive infrastructure overhauls.

Australia's first biomethane-to-gas project will see thousands of Sydney homes and businesses using renewable green gas for cooking, heating and hot water.

Jemena has signed an agreement with Sydney Water to generate biomethane at the Malabar Wastewater Treatment Plant, in South Sydney. The zero-carbon emission, high-quality biomethane gas will be injected into Jemena's New South Wales gas distribution network – the largest in Australia with 1.4 million customers.

The Malabar Wastewater Treatment Plant (WWTP), located near the Malabar Headland National Park, is one of Sydney Water's multiple Anaerobic Digestion (AD) plants. The bulk of the current AD Biogas output is used for electrical power generation and water heating. The balance of biogas that cannot be used via site processes is combusted through waste gas burners.

The Malabar Biomethane Injection Project will demonstrate the process of upgrading biogas produced from the anaerobic digestion process at Sydney Water's Malabar wastewater treatment plant to biomethane for injection into the gas distribution network. The project involves the installation of gas cleaning and upgrading equipment that will be located at Sydney Water's Malabar wastewater treatment plant. This infrastructure will upgrade biogas to biomethane and will be connected to Jemena's natural gas network. The Malabar facility will also be one of the first participants in GreenPower's renewable gas certification pilot, which will help energy customers access renewable gas in the same way they can purchase renewable electricity.

Origin Energy has signed an agreement with Jemena for the biomethane produced at the Malabar facility and will offer business customers the option to benefit from the renewable gas.

Jemena's research has found that in New South Wales alone there are enough potential sources of biomethane – wastewater plants, landfill and food, agricultural, and crop waste – to generate about 30 petajoules of biomethane each year. This is approximately enough gas to meet the needs of all of Jemena's current residential customers in New South Wales.

Renewable gas is particularly important for heavy industry and manufacturing - providing a pathway to lower emissions. Some industries just aren't able to electrify, either because it is too costly or they rely on gas for their operations and production processes. Industries like steel, fertiliser, tiles and brick manufacturers are all reliant on gas and will need a carbon-neutral or low-emission alternative now and into the future. Biomethane and renewable hydrogen can provide that alternative.

**Figure 4-4 Jemena Malabar biomethane injection project, Malabar, New South Wales**

Source: Renewable gas emerging as a key piece in emissions reduction puzzle (afr.com) (www.afr.com)

## Reporoa organics processing facility, New Zealand

Lead Organisation Ecogas, Location Reporoa, in the central North Island New Zealand.

Started August 2020, and fully operational by October 2022.

$30m Total project cost.

New Zealand's first large-scale food waste-to-bioenergy facility at Reporoa, in the central North Island, is owned by Ecogas, a joint venture between Pioneer Energy and Ecostock Supplies, and situated on land owned by Turners & Growers (T&G), a New Zealand fresh produce business. T&G leased the land to Ecogas and, in return, buying renewable electricity, heat and $CO_2$ from Ecogas to power its tomato glasshouses 450 metres from the facility. The circular economy facility turns 75,000 tonnes of organic waste, from businesses and kerbside food scrap collections throughout the North Island, into sustainable, renewable energy products. The facility creates enough energy to annually power up the equivalent of around 2500 households in the region, produce clean bio-fertiliser for approximately 2000 hectares of local farmland, and provide $CO_2$ and heat to enhance the growth of tomatoes in T&G Fresh's local glasshouse.

The facility uses anaerobic digestion - a technology already used successfully overseas - to create renewable energy (electricity, heat and biogas) as well as Fertify Regenerative Fertiliser. Fertify is applied to farmland around the district as a renewable alternative, closing the food and energy loop by returning nutrients from our food back into our soils.


**Figure 4-5 Ecogas's Reporoa organics processing facility, New Zealand**

Source: https://www.ecogas.co.nz/reporoa

## JBS Australia and Energy360 bioenergy system

Lead Organisation JBS Australia, Location Oakey, Queensland.

Started 2022 and completed in August 2024.

$11.1m Total project cost.

JBS has completed the installation and commissioning of the new biogas harvesting system at Beef City, an integrated feedlot and processing facility at Purrawunda, to offset energy requirements on-site. The completed systems will contribute to a total annual reduction of about 57,000t of carbon dioxide equivalent emissions. JBS previously didn't cover its wastewater lagoons, and this project eliminated this fugitive carbon dioxide.

JBS partnered with AGL-owned biogas handling company Energy360 to install bioenergy infrastructure at Beef City that enables a circular wastewater treatment process.

Two gas-tight pond covers have been installed over pre-existing anaerobic wastewater lagoons, allowing naturally occurring biogas to be captured and redirected for use as a production heat source. These covers also prevent waste odour from entering the atmosphere.

This biogas is now displacing a significant portion of Beef City's natural gas requirements. This provides Beef City with substantial Greenhouse Gas abatement well into the future, as well as reducing costs by lessening the plant's reliance on natural gas, the company said.

The additional inclusion of a de-sulphurisation system underneath the lagoon covers has allowed for more oxygen to be introduced, which lessens the production of other hazardous gases.

The biogas is used to heat boilers, to generate hot water used in processing operations. Daily replacement of LNG has been as high as 10,000 cubic metres of biogas per production day, which significantly lessens our total natural gas consumption and significantly reduces our carbon dioxide equivalent emissions.

**Figure 4-6 JBS Australia and Energy360 bioenergy system, Oakey Queensland**

Source: JBS Australia's Beef City bioenergy system now in operation — JBS Foods (jbsfoodsgroup.com)

## AJ Bush & Sons Boilers and Biogas recovery projects

Lead Organisation AJ Bush & Sons, Location Beaudesert, Queensland.

Started 2018.

$11m Total project cost.

AJ Bush invested in clean technology to improve its production efficiencies and cut energy costs throughout its operations to construct a new Covered Anaerobic Lagoon (CAL) to capture the biogas produced during effluent treatment, for use in firing on-site boilers. The project also involved upgrades to the existing biogas infrastructure at the AJ Bush rendering facility near Beaudesert, Queensland. The $11 million renewable energy project will be developed at AJ Bush Rendering Plant in the Scenic Rim after renewables company BE Power Solutions. The project also entailed a new solar PV PPA of the existing bioenergy PPA located at AJ Bush's rendering facility with ReNu Energy.

The company's plant has the largest rendering capacity in Australia, creating by-products from meat processing for domestic and export markets. By partnering with BE Power Solutions they are able to transform waste streams into energy sources. The facility developed its a hybrid biogas-solar-battery power plant to potentially remove the company from the electricity grid and create a renewable energy hub to attract complementary manufacturing industries seeking affordable power.

The site is located in the Bromelton State Development AREA (SDA). Bromelton is a nationally significant green freight precinct. It is an intermodal, industrial and logistics hub, strategically located within one hour of the Port of Brisbane.

**Figure 4-7 AJ Bush's Beaudesert biogas recovery plant in Queensland**

## 2024 Selected hypothetical Biogas project

This hypothetical project includes a complete facility with a feedstock receival station, pre-treatment, anaerobic digestion and power generation from the biogas produced, although an alternate production pathway is to clean up the biogas to biomethane to be used as a replacement for natural gas or coal seam gas. For the purposes of this report, we have used this configuration to match existing installed projects in Australia. There are several projects where biomethane is proposed, but not yet proven in terms of ongoing profitability in Australia, as yet.

The hypothetical power station capacity has been selected at 2 MW, with nominal 2 x 1,200 kW CHP co-generators. This configuration is less than the 5 MW threshold that would require additional equipment to meet NEM generation standards. The facility would have a Connection Agreement, based on a Large Customer Negotiated Customer Connection Contract (LCNCC) – Single Premises with Generation.

**Table 4-36 Biogas hypothetical plant configuration and performance**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology | | Anaerobic digestion with CHP generators | Complete system involves feedstock logistics, pre-treatment of feedstock, digestors, gas management, CHP units, heat recovery, electrical generation equipment and balance of plant |
| Fuel source | | Organic feedstocks | Agricultural residues, energy crops, food waste, manures, sewage, MSW |
| Make model | | Australian biogas consultants, CHP OEM's | Integrated custom systems from Australian biogas system suppliers and OEM's |
| Unit size (nominal) | MW | 2.4 MW Electrical<br>2.4 MW Thermal | Assumed generation using 2 x 1,200 kW CHP co-generators (2 units to provide redundancy) |
| Number of units | | 1 biogas system<br>2 CHP Units | Assume 2 x generator units for reliability |
| Gas Methane Number | MZ d | 135 | Biogas from AD plant (Minimum 117) |
| Gas Fuel LHV | kWh/Nm$^3$ | 4.5 | |
| **Performance** | | | |
| Total plant size (Gross) | MW | 2.4 Electrical<br>2.4 MW Thermal | Anaerobic digestion plant supplying biogas to 2 x 1.2 MW CHP co-generators |
| Total plant size (Net) | MW | 2 Electrical | |
| Biogas Production | NmÂ$^3$/a | 7,560,000 | @ 55% Methane and 8400 hours |
| Methane Production | NmÂ$^3$/a | 4,158,000 | @ 8400 hours |

| Item | Unit | Value | Comment |
|---|---|---|---|
| Electricity Generation | kWh /a | 16,700,000 | @ 8400 hours |
| Heat Generation | kWh /a | 17,100,000 | @ 8400 hours |
| Digestate | $m^3$ /a | 92,500 | Assume 5% |
| CHP Electrical Efficiency | % | 42 | |
| Site Parasitic Electrical Load | % | 8 | |
| Site Parasitic Heat (Water) Load | % | 25 | |
| Average Planned Maintenance | Days / yr. | 15 | |

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024, given the above discussion on typical options and current trends.

The assumed biogas project involves a whole of facility scope of work including:

- Generation type - Anaerobic digestion of organic feedstocks
- Fuel types - Agricultural residues, energy crops, food waste, manures, sewage, MSW
- Capacity of 900 $Nm^3/h$ biogas
- Annual amount of biogas produced - 7,560,000 $Nm^3/a$ @ 55% methane and 8400 hours
- Onsite generation equipment – 2 MW net generation using 2 x 1,200 kW CHP co-generators, with exhaust gas heat exchangers, jacket water cooler, oil cooler, hot water heat exchanger, gas treatment, oil tanks and stack
- Logistics receivals area, roads, site office and amenities
- Feedstock storage capacity for 2 days
- Sorting, pre-treatment, feeding systems and pasteurization of feedstock
- Anaerobic digestion tank infrastructure for hydrolysis, digestion, outlet and liquid storage tanks
- Ancillary equipment including pumps, heat exchangers, air dosing, tank mixing and access equipment and balance of plant
- Separation, post processing and digestate equipment
- Gas management and flare infrastructure and equipment
- Pipework, valves, instrumentation and process control equipment
- Site wide electrical and power distribution infrastructure
- Commissioning, testing, critical spares and operational readiness

**Table 4-37 Biogas hypothetical project timeline**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Project timeline** | | | |
| Time for development | Years | 2 | includes pre/feasibility, design, approvals, procurement, etc. |
| First Year Assumed Commercially Viable for construction | Year | 2024 | |
| EPC programme | Years | 2 | For NTP to COD. |
| ▪ Total Lead Time | Years | 1 | Time from NTP to long lead items on site. |
| ▪ Construction time | Weeks | 52 | Time from site establishment to COD. |

| Item | Unit | Value | Comment |
|---|---|---|---|
| Economic Life (Design Life) | Years | 20 - 25 | Assuming corrosion resistant materials utilised |
| Technical Life (Operational Life) | Years | 30 | Assuming overhauls of CHP units at OEM intervals |

### Biogas hypothetical project cost estimates

Costs used in this 2024 Biogas hypothetical assessment have been aggregated from OEM quotes from recent projects and a nominal selection of associated infrastructure. CPI and cost escalation are estimated to involve increases of 4% for this type of industrial equipment from 2023. The main contributors to the CAPEX cost growth for building construction costs are due to ongoing skilled labour shortages, wage inflation and the passing through of manufacturing costs from energy intensive materials, recent price increases for electricity and freight and increasing fuel and operational costs.

The key issue in preparing bioenergy CAPEX figures is in defining where the battery limits are on the value chains required for continuous power generation in all states of Australia, across all seasonality issues for the feedstocks and the availability of grid connections of sufficient capacity for where the generating plant is located (usually in regions with low population).

Utilizing unit generation costs from Europe and the America's requires the comparative scenarios to be clearly presented and defined closely. The returns on investment for many Australia bioenergy projects have been modest to low, due to the variability in feedstock availability, price, and logistics input costs; plus, the low pricing on the net electricity revenue and generation certificates, as well as the lack of carbon pricing to date.

The following table provides cost parameters for the hypothetical Biogas project as outlined above.

**Table 4-38 Cost estimates for the hypothetical biogas project**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX – EPC cost** | | | |
| Relative cost | $ / kW | $16,000 | Net basis for 2000 kW. Relative cost does not include land and development costs. |
| Total Capital cost | $ | $29,120,000 | |
| ▪ Equipment cost | $ | $11,648,000 | 40% of EPC cost – typical. |
| ▪ Installation cost | $ | $17,472,000 | 60% of EPC cost – typical. |
| **Other costs** | | | |
| Cost of land and development | $ | $2,912,000 | Assuming 10% of CAPEX. |
| Feedstock supply costs | $M | N/A | Typically, given the scale of the plant, the feedstock would be delivered by road. As such the fuel transport costs become an ongoing OPEX cost. |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / MW (Net) | $416,000 | Aggregated for scope listed above |
| Variable O&M Cost | $ / MWh (Net) | 72.8 | Assuming AD plant and CHP systems over 8400 hrs |
| Annual Fixed O&M Cost | $ | $832,000 | |
| Annual Variable O&M Cost | $ | $1,223,040 | |
| Total annual O&M Cost | $ | $2,055,040 | For 2 MW over 8400 hrs |

### 4.11.6 Biomass generators using wood waste

#### Overview

The use of biomass for electricity generation can take many different forms and cover a variety of technologies, some well proven and others still in the pilot phase. Broadly speaking biomass is considered to cover any organic matter or biological material that can be considered available on a renewable basis. This includes materials derived from animals and/or plants as well as waste streams from municipal or industrial sources.

#### Typical options

Producing electricity from biomass can be completed via the following process:

- Incineration: This involves the combustion of solid biomass in a steam generation boiler, typically grate or circulating fluidised bed (CFB) type. The steam is then used in a traditional steam turbine to generate electricity. The solid biomass can typically be forestry products (ie wood chips, sawdust, etc), harvest residues (ie sugar cane, bagasse, etc), municipal solid waste, or refuse-derived fuel (RDF)
- Anaerobic digestion: This is a biological process where biomass is feed into a reactor where microorganisms assist in the decomposition process. The off gas that is produced, called biogas, is a mixture of methane and carbon dioxide which can be combusted, with some clean up, in either a reciprocating engine or gas turbine to produce electricity
- Gasification: This is a thermochemical process that transforms any carbon-based biomass into a gas by creating a chemical reaction without burning the material. This reaction combines those carbon-based materials with small amounts of air or oxygen to produce primarily a mixture of carbon monoxide and hydrogen. Additional treatment is required to remove any pollutants and or impurities. The gas produced is called “synthesis gas” or “syn gas”. This gas is the consumed in either a reciprocating engine or gas turbine to produce electricity
- Biofuels: This is the process of refining liquid fuels from renewable biomass such as ethanol and biodiesel. Although possible to use in power generation, liquid biofuels are most commonly used in the transport industry.

The following figure shows typical value chains for transforming raw biomass feedstocks for biomass cogeneration applications:

#### Recent trends

Internationally there has been a recent uptake of electricity generation using wood pellet produced from sustainably managed working forests. Examples of such plants include conversion of four 660 MW coal fired units of Drax Power Station in the UK, Atikokan Unit (205 MW), Canada and Thunder Bay Generating Station in Ontario, Canada (163 MW). In the last decade Japan was undergoing a biomass-to-energy boom since the introduction of a feed-in-tariff (FIT) policy in 2012. The FIT is still continuing for projects with less than 10 MW capacity. The Feed-in-Premium (FIP) for capacities larger than 10 MW is decided through a tender system. In Australia the most common form of power generation from biomass is incineration / combustion in subcritical steam boilers. The biomass used as the primary feedstock is typically a bi product from the forestry industry such as wood waste from sawmills or harvest residues such as bagasse from the sugar cane industry. More recently municipal solid waste and RDF feedstocks are also being considered with two plants now under construction in WA and a number considered in the NEM.

Currently the feedstocks used in power generation are bi products from other industries. This generally has the advantage of a low-cost fuel source however the quantities available are limited by the primary harvesting or manufacturing process. Harvesting a feedstock for the sole purpose of power generation has not yet been implemented for a project on the NEM.

The input cost structures are significantly different for other feedstocks, particularly in the harvesting, collection, storage and logistics. Woodchip is used to provide a comparable energy cost for this exercise, since it can be defined as a tradeable commodity that can be used and priced locally, or for export. Other lower cost feedstocks are difficult to price and quantify energy content unless quality is consistent and supply is from consistently available locations across the seasonality spread.

Biomass power plants using incineration or combustion technologies are typically deployed with unit sizes in the range of 20 to 40 MW with or without process heat generation. Significantly higher plant sizes are not viable due to the limitations in available feedstock within a practical transport distance from the plant.

## Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project which includes both power generation and process heat. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024 given the above discussion on typical options and current trends.

**Table 4-39 Configuration and performance**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| 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 | |
| Main steam pressure | MPa | 7 | |
| Main steam temperature | °C | 470 | |
| Process steam pressure | Bar | 5.74 | |
| Process steam temperature | °C | 162.3 | |
| Process steam mass flow rate | kg/s | 16.0 | Approximately 37% of main steam to turbine |
| Condenser pressure | kPa abs | 7.5 | |
| **Performance** | | | |
| Electrical plant size (Gross) | MW | 30 | 25°C, 110 metres, 60%RH |
| Process heat capacity | MW | 44.25 | 25°C, 110 metres, 60%RH |
| Auxiliary power consumption | % | 7.3% | |
| Electrical plant size (Net) | MW | 27.8 | 25°C, 110 metres, 60%RH |
| Seasonal Rating – Summer (Net) | MW | 27.4 | 35°C, 110 metres, 60%RH |
| Seasonal Rating – Not Summer (Net) | MW | 28.0 | 15°C, 110 metres, 60%RH |
| Heat rate at minimum operation (Electric) | (GJ/MWh) HHV Net | 18.092 | 25°C, 110 metres, 60%RH |
| Heat rate at maximum operation (Electric) | (GJ/MWh) HHV Net | 16.255 | 25°C, 110 metres, 60%RH |
| Thermal Efficiency (Electric) at MCR | %, HHV Net | 22.2% | 25°C, 110 metres, 60%RH |
| CHP Efficiency | %, HHV Net | 57.4 | 25°C, 110 metres, 60%RH |
| **Annual Performance** | | | |
| Average Planned Maintenance | Days / yr. | 22.8 | |

| Item | Unit | Value | Comment |
|---|---|---|---|
| Equivalent forced outage rate | % | 4% | |
| Annual capacity factor | % | 89.8% | |
| Annual electricity generation | MWh / yr. | 218,688 | Provided for reference based on assumed capacity factor. |
| Annual degradation over design life - output | % | 1-2% for first 18 months and then flat/low level degradation | |
| Annual degradation over design life – heat rate | % | 0.2% | Assuming straight line degradation. |

Table 4-40 Technical parameters and project timeline

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Technical parameters** | | | |
| Ramp Up Rate | MW/min | 1.2 | Based on 3%/min standard operation |
| Ramp Down Rate | MW/min | 1.2 | Based on 3%/min standard operation |
| Start-up time | Min | Cold: 420<br>Warm: 120<br>Hot: 60 | Standard operation. |
| Min Stable Generation | % of installed capacity | 40% | Without oil support |
| **Project timeline** | | | |
| Time for development | Years | 3 | includes pre/feasibility, design, approvals, procurement, etc. |
| First Year Assumed Commercially Viable for construction | Year | 2024 | |
| EPC programme | Years | 3 | For NTP to COD. |
| ▪ Total Lead Time | Years | 1.75 | Time from NTP to steam turbine on site. |
| ▪ Construction time | Weeks | 65 | Time from steam turbine on site to COD. |
| Economic Life (Design Life) | Years | 30 | |
| Technical Life (Operational Life) | Years | 50 | |

## Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-41 Cost estimates

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX – EPC cost** | | | |
| Relative cost | $ / kW (electrical energy basis)<br><br>$ / kW (electrical and thermal energy basis) | 8,180<br><br>3,156 | Net basis (plant includes process heat as well). Relative cost does not include land and development costs. |
| Total EPC cost | $ | 227,404,000 | Plant includes electrical as well as thermal energy as output (thermal energy is a bleed from steam turbine)<br>Plant electrical cost component of total for reference ($179,352,000) - plant without thermal energy component<br>Plant process heat cost component of total for reference ($32,189,000) - plant with electrical and thermal energy |
| ▪ Equipment cost | $ | 136,442,000 | 60% of EPC cost – typical. |
| ▪ Installation cost | $ | 90,961,000 | 40% of EPC cost – typical. |
| **Other costs** | | | |
| Cost of land and development | $ | 20,466,378 | Assuming 9% of CAPEX. |
| Fuel connection costs | $M | N/A | Typically, given the scale of the plant, the feedstock would be delivered by road. As such the fuel transport costs become an ongoing OPEX cost as part of the fuel delivery cost. |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / MW (Net) | 184,085 | AEMO costs and technical parameter review, 2023 (escalated) |
| Variable O&M Cost | $ / MWh (Net) | 10.74 | AEMO costs and technical parameter review, 2023 (escalated) |
| Total annual O&M Cost | $ | 7,466,602 | |

### 4.11.7 Biodiesel production

#### Overview

Biofuels are renewable fuels derived from biological sources such as waste, vegetable oils, and animal fats. They can be used as substitutes or blends for fossil fuels in transport and other sectors, offering a potential way to reduce greenhouse gas emissions and achieve net zero targets. Unlike fossil fuels, such as petroleum, coal, and natural gas, biofuels can reduce greenhouse gas emissions by recycling the carbon dioxide that is absorbed by the biomass during its growth.

According to the International Energy Agency, biofuel demand in 2022 reached 170 billion litres.1 To align with the Net Zero Scenario, as defined by the Agency, biofuel production would need to more than double by 2030, requiring an average growth of 11% per year. Hence, it is anticipated that demand for biofuels will continue to surge in the 2020's as their appeal to decarbonise hard to abate industries, such as transport, is matched with the pace of decarbonisation efforts required to meet global targets.

The two most common types of biofuels in use today are ethanol and biodiesel. Ethanol is an alcohol which can be utilised as a blending agent with gasoline. Similarly, biodiesel is another liquid fuel which acts as a cleaner-burning replacement for petroleum-based diesel fuel and can also be blended up to 20% for most engines. The International Energy Agency predict ethanol and biodiesel to make up 87% of all biofuels global demand in 2026, with a total of 110 and 50 billion litres per year of ethanol and biodiesel respectively.

The current Biofuels value chain includes the following stages:

1. Feedstock Production
2. Transportation to Bio-Refinery
3. Biofuel Production
4. Biofuel Blending
5. Transportation to End User
6. Storage and Use

Typical traditional feedstocks for biodiesel are:

- Vegetable oils including oilseed such as soybean, canola, cotton, carinata, palm and sunflower.
- Oil trees
- Algae oils
- Tallow from meat works
- Used cooking oil (UCO)

Biodiesel can be added to mineral diesel in any number of different blend concentrations. Some examples are B100 -100% biodiesel; B85 -85% biodiesel, B20 -20% biodiesel and B5 -5% biodiesel.

Worldwide it is generally accepted that blends of B20, or less, can be used in normal diesel engines without any adverse effects. However, some engine manufacturers do not extend warranties for engines running biodiesel blends, although a B20 blend provides a fuel quality benefit with improved lubricity and fuel cetane rating improvement. In Australia, B5 or lower can be used in any engine, but only a small number of engine manufacturers warrant the use of blends with higher biodiesel content. Some individual fleets have had up to B100 in regular use; although these generally have specialist engine maintenance, and the fleet operator assumes legal responsibility for the use of these fuels.

## Processing technologies

There are many potential feedstocks and processing technologies for biofuels and biodiesel production.

The following processes can be used to drive the reaction:

- Common batch process uses a catalyst and heat
- Supercritical processes not requiring a catalyst; instead, high temperature and pressure is used
- Ultrasonic methods use ultrasonic sound waves to cause the mixture of reactants, producing both a heating and mixing effect; this negates the need for catalysts
- Microwave methods that are used to heat and mix the reactants, instead of catalysts
- Lipase catalysed methods use Lipase enzymes as a catalyst to the reaction process.
- Hydrothermal liquification (HTL)
- Thermal
- Gasification
- Hydrotreated Vegetable Oil (HVO)

## Recent biofuels market developments

In renewable fuel markets worldwide, there is a clear difference in pricing for biofuels produced from sustainably sourced waste oil and animal fat feedstocks compared to biofuels produced from virgin oil crop feeds such as soybean and rapeseed. In Europe, renewable diesel produced from sustainable feeds are eligible for double counting capture at US$400-$600/MT higher value than renewable diesel produced with crop oil feeds. In the California market, renewable diesel produced with used cooking oil captures an additional US$250-$300/MT of incentives compared to using virgin soybean oil. With these huge differences in product prices, refiners need to ask if their capital investment is properly deployed to capture this additional value.

The following figure provides an insight into the range of biofuel costs in the US, that the Jim Lane Biofuels Digest publishes every day.

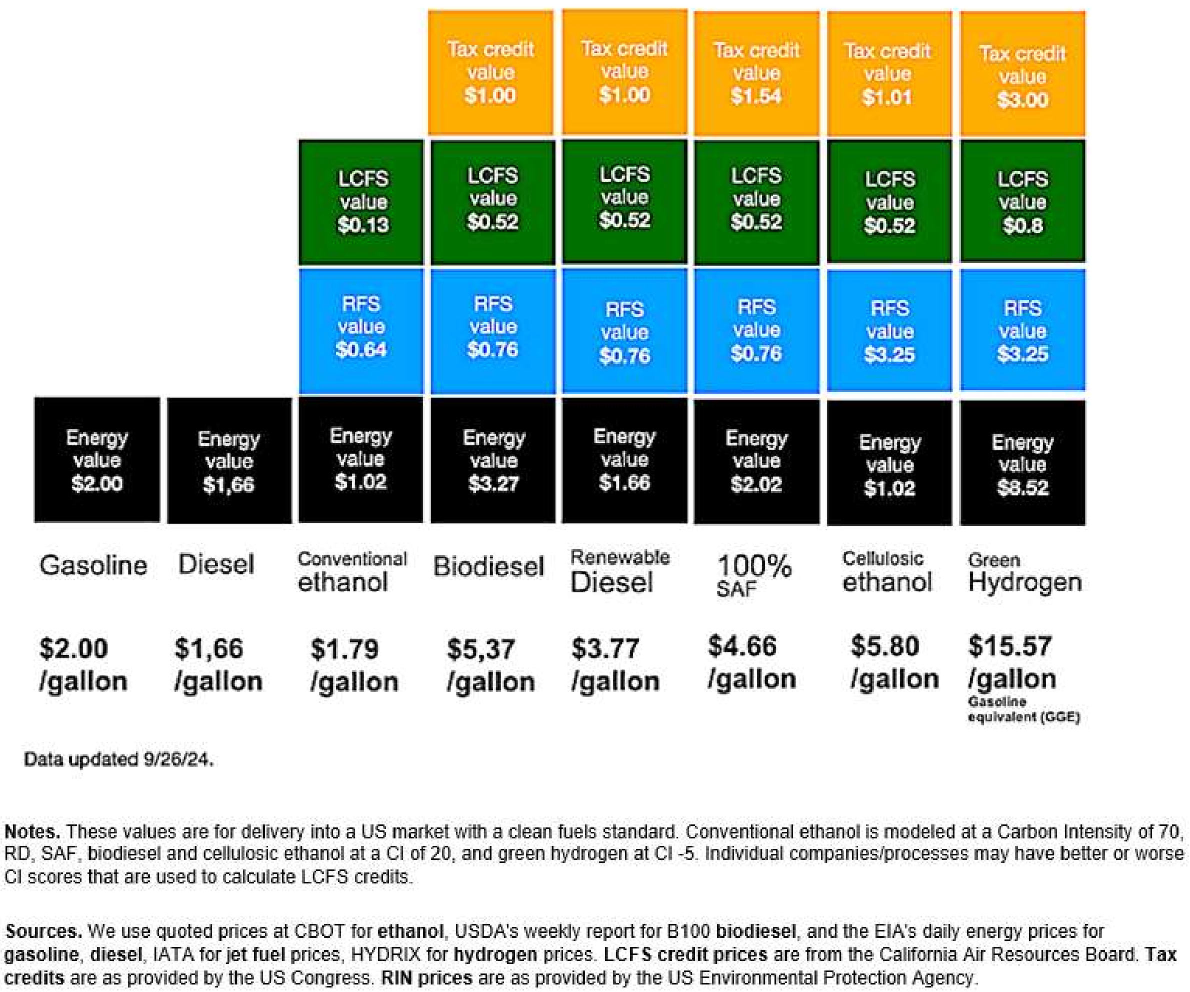



**Figure 4-8 US daily biofuel prices**

Source: Jim Lane Biofuels Digest Daily e-News 26th September 2024: https://www.biofuelsdigest.com/bdigest/

## Biofuels emerging technologies

There have been many recent developments and emerging technologies developed for Biodiesel production. By producing fuel using sources with lower carbon intensity than traditional petroleum-based products, the biofuels sector is well-positioned to play a major role in reducing greenhouse gas emissions through renewable liquid transportation fuels as a solution. The major challenge facing the biodiesel industry is securing the supply of suitable feedstocks for the production of biodiesel, with the diversion of agricultural production from food or feed to fuel. Therefore, there is continual research into the use of alternative or lower grade feedstocks including marine algae, coffee grounds, pongamia, oiltrees and high oil tobacco.

Research into biodiesel production feedstocks from non-food sources is focussed on inedible oils or waste products which have higher free fatty acid levels (FFA). Processing waste oils and animal fats face challenges from high levels of contaminants such as nitrogen, metals and polyethylene compared to virgin oil feeds. In order to maximize product yields and catalyst cycle length, these contaminants need to be removed. This means feedstock pre-treatment and a renewable fuel process technology capable of operating with contaminants. Generally, biodiesel quality feedstock should be below 2% FFA. If biodiesel production methods were developed so that higher FFA levels were acceptable, there would be potential for more meat or agricultural waste products that have higher FFA to be used in biodiesel production. Current biodiesel research is also focused on developing the most efficient methods of obtaining fatty acids from the anaerobic digestion of organic waste streams, such as domestic and animal waste.

There are also recent innovations into small packaged biodiesel production units, whereby this seemingly complex process is simplified to containerised designs for point of source generation on farm. For example, there are biodiesel production units contained in a shipping container that can produce biodiesel from appropriate feedstock in the location where the feedstocks are produced. This system does not require an external source of energy; it uses the biodiesel it produces to generate its own power. Such a system could be used at a meat processing facility to produce biodiesel on site.

There is potential for 'drop-in' biofuels using emerging second-generation processes as alternatives to the traditional FAME biodiesels that have been around for many years. However, real projects are still being developed in Australia, and the cost effectiveness of the second-generation methods still have a significant gap in most countries compared to FAME.

## ‘Green’ and renewable diesel developments

‘Green’ diesel refers to diesel substitute fuels with lower emissions relative to petroleum-derived diesel, but there are in fact a range of products which meet this definition.

Green diesel falls into two broad categories:

- Biodiesel
- Renewable diesel

Biodiesel is produced through transesterification, wherein vegetable oils or animal fats are chemically reacted with an alcohol, as shown in Figure 4-9 below. It can generally only be used up to a 20% blend in diesel equipment before modifications are required, due to its different properties (eg, energy density).

Stringent environmental regulations aimed at curbing greenhouse gas emissions are driving the adoption of Next-Generation renewable biofuels. Governments worldwide are enacting policies to reduce carbon emissions and promote cleaner fuel options. Next-Generation biofuels offer significant reductions in greenhouse gas emissions compared to conventional fossil fuels, making them an attractive alternative. For instance, the European Union's Renewable Energy Directive (RED II) mandates that at least 14% of transportation fuels must come from renewable sources by 2030, driving the development and adoption of Next-Generation biofuels across Europe. Recent advancements involve the use of waste-based feedstocks, such as agricultural residues and municipal solid waste, to produce biofuels with reduced carbon footprints.

Renewable diesel can be produced from a wider range of feedstocks and through a variety of technology platforms and has very similar properties to petroleum diesel. It can be used a ‘drop-in’ substitute and does not require blending, although many of the production pathways are still being scaled up and commercial quantities may not be readily available for several years.

The following sections will compare the fuel characteristics of Biodiesel and HVO, and the different production routes. Renewable diesel offers alternate pathway opportunities in the biofuels space, given the extraordinary growth potential with major oil companies embracing renewable diesel to future proof existing assets.

If this was to occur, the feedstock supply issues will need to see additions from corn or soybeans feedstocks, to include growing other oilseeds like canola and sunflower on a larger scale, importing other vegetable oils, or using other feedstocks such as beef tallow to produce renewable diesel fuel.

Biomass feedstocks (eg spruce, corn stover and wheat straw) can also be used to replace petro-diesel through the production of renewable diesel and gasoline via fast pyrolysis and hydroprocessing technologies. The production costs of renewable diesel are proportional to the feedstock cost. The net energy ratios (NERs) of the process, which is the ratio of the energy content of the output product to fossil fuel inputs, also varies pending the level of preparation and logistics systems available for collection and supply to the processing site. Of the renewable resources, biomass is the most suitable to be directly converted to a liquid renewable fuel to replace fossil fuel. So, the holy grail is in finding a ‘waste’ or low value renewable feedstock that has already been harvested and can be automated for mechanical collection and transport.

Another form of renewable diesel is produced from Hydrotreated Vegetable Oil (HVO), which is a drop-in fuel, with no engine modifications required. HVO fuel has chemical and physical properties like those of diesel fuel, however, its fossil-free composition and low carbon content differentiate it from diesel and make it attractive to those seeking a sustainable fuel option. HVO also has approximately 7% less fuel density, limited aromatic and sulphur content, and a higher cetane value versus diesel fuel.

The properties of HVO and biodiesel closely resemble conventional diesel. However, higher energy density, better cold flow properties, and higher blend ranges, make HVO a better option.

Although both derived from similar feedstocks, HVO renewable diesel and biodiesel have different chemical compositions. HVO has higher energy density, less impurities, and better cold flow properties to biodiesel, allowing for up to 100% blend rates, a key factor leading to its popularity.

**Table 4-42 Comparison of fuel characteristics between HVO, biodiesel, and conventional diesel**

| Property | Unit | HVO Diesel | Biodiesel | Conventional Diesel |
|---|---|---|---|---|
| Density at 15°C | $Kg/m^3$ | 780 | 875 | 820 |
| Engine modification | - | Nil | Nil | Nil |
| Cetane rating | Dimensionless | >70 | 54-56 | >51 |
| Blending range | % | 0-100% | 5-20% | 100% |
| Energy density | MJ/L | 34.4 | 32.6 | 38 |
| Storage stability | - | Stable | Less stable | - |
| Cloud point | °C | -32 | 0 to -17 | -1 to -10 |
| Pour point | °C | -58 | -9 to -15 | -17 to -30 |

The following figure shows typical green and renewable diesel production routes:

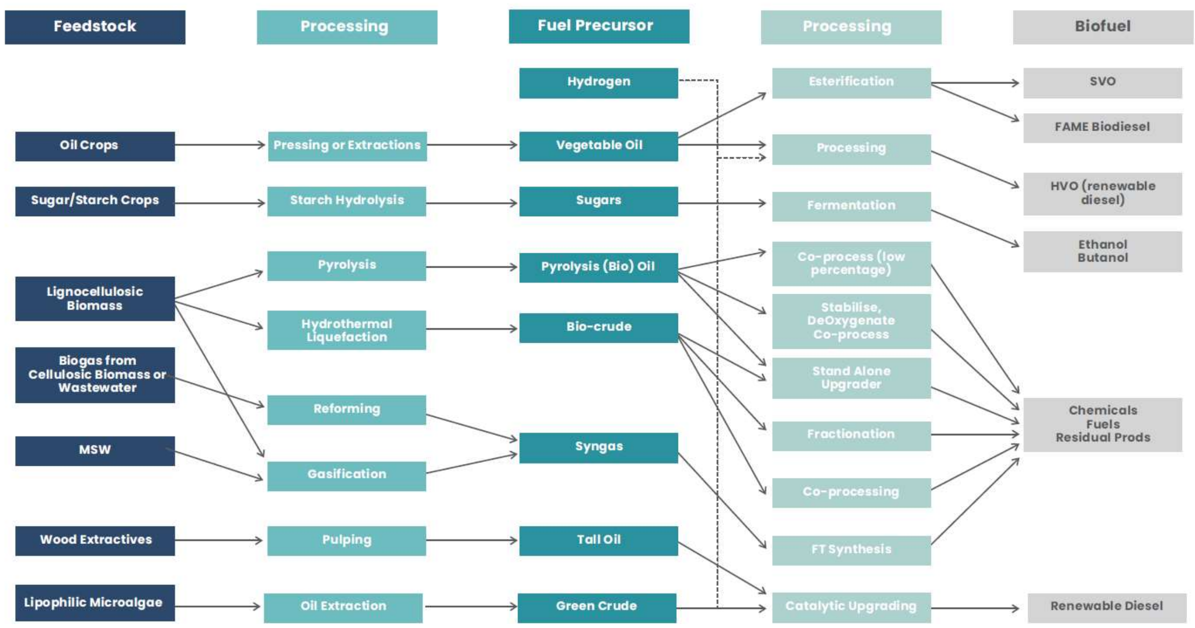



Figure 4-9 Green diesel production routes (source: Deloitte, 2021)

### Biofuels trend in Australia

Biofuel production has grown significantly in Australia from zero commercial production in 2000 to over 200 million litres in 2021. In 2021, ARENA released Australia's first national bioenergy roadmap which states by 2030 the bioenergy sector could create around tens of thousands of new jobs, reduce emissions by 9%, divert waste from landfill, and enhance fuel security.

The Figure below provides an overview of the operating and decommissioned biofuel facilities in Australia. Traditionally, most Australian biofuel facilities have produced bioethanol (80%). However, with the decommissioning of the United Petroleum bioethanol facility in 2020 and the new renewable diesel projects announced in Queensland, the majority of biofuels will be from renewable diesel, which is a direct substitute for conventional diesel, and which is suitable for a 'drop-in' to existing internal combustion engines (ieno blending with conventional diesel is required, it can be used as is).

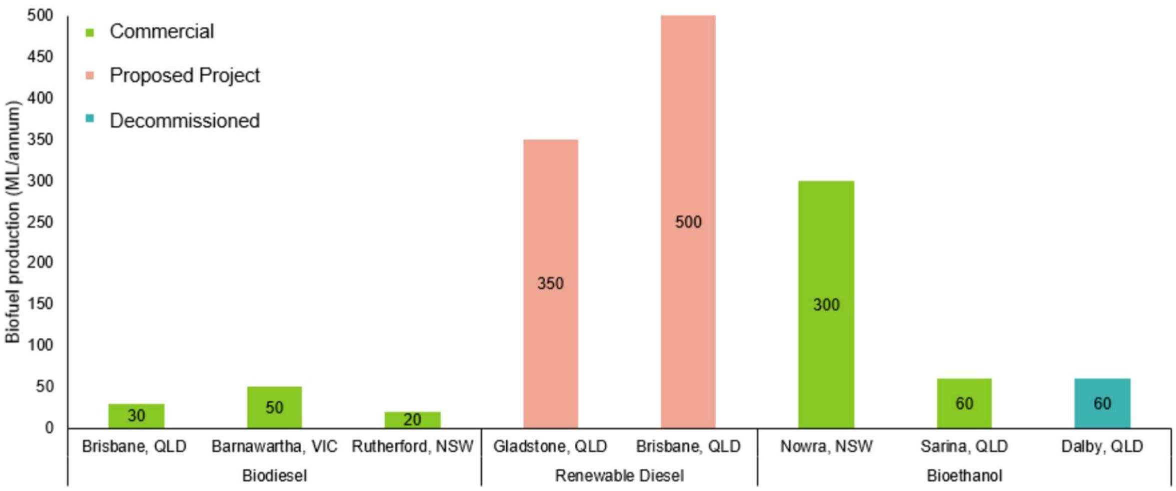



**Figure 4-10 Summary of biofuel production in Australia**

Source: australia-bioenergy-roadmap-report.pdf (arena.gov.au) Low carbon liquid fuels | Austrade International

## 4.11.8 Recent trends on biodiesel cost of production

Renewable diesel and biodiesel share similar input feedstock processes; however, their point of divergence lies in their respective production processes.

HVO and biodiesel can use a diverse range of feedstocks to produce a sustainable and environmentally friendly alternative to conventional diesel fuel.

Feedstocks for HVO diesel and biodiesel can come from either 1st or 2nd generation sources:

- 1st generation feedstocks are derived from primary raw materials, often obtained by repurposing crops meant for food or using land specifically for energy production
- 2nd generation feedstocks are derived from non-food biomass or waste materials.

After oil has been extracted from the feedstock, it can either be converted into FAME biodiesel or HVO diesel.

### HVO Renewable diesel

HVO (Hydrotreated Vegetable Oil) renewable diesel is produced from vegetable oils or animal fats.

Hydroprocessing is the main chemical process involved in making HVO renewable diesel.

Hydroprocessing involves adding hydrogen gas to the feedstock in the presence of high temperature and pressure. This process helps break down the long-chain fatty acids in the feedstock, which improves cold flow properties, reduced viscosity, increases cetane number, and removes impurities.

After Hydroprocessing, the fluid is passed into a hydrocracking stage, which aims to further improve the chemical structure of the HVO to better align with conventional diesel.

### FAME biodiesel

FAME biodiesel, also known as Fatty Acid Methyl Ester biodiesel, is produced from vegetable oils or animal fats through a process called transesterification.

Transesterification is the main chemical reaction where the fats in the feedstock are converted into biodiesel. It involves mixing the feedstock with an alcohol, typically methanol, and a catalyst (usually sodium or potassium hydroxide). The alcohol reacts with the fats in the presence of the catalyst to break them down into glycerin (which can be sold separately) and Fatty Acid Methyl Esters (FAME) – which is the biodiesel.

After the transesterification reaction, the mixture contains biodiesel, glycerin, and other by-products. The glycerin settles to the bottom of the separation unit due to its higher density, and the biodiesel floats on top, which can be extracted and stored separately in its pure form.

## 4.11.9 Comparison of HVO and renewable diesel production process

The following figure depicts a comparison between HVO and renewable diesel production process.

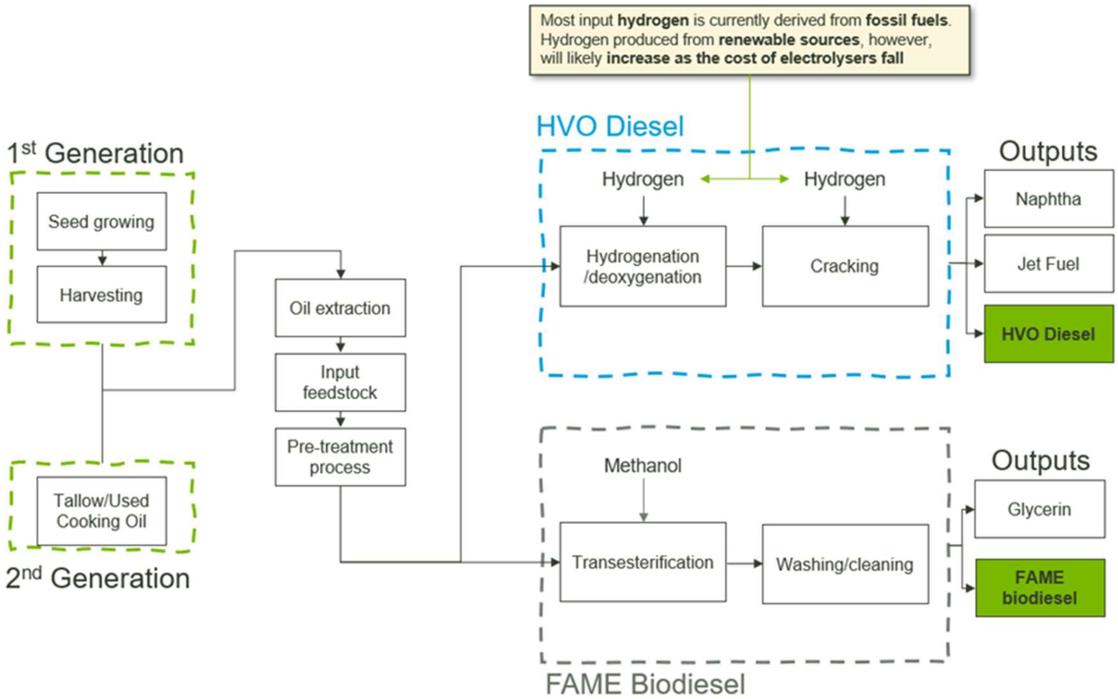



**Figure 4-11 Production process comparison between HVO and FAME biodiesel**

## 4.11.10 Levelised comparison between HVO and biodiesel production processes

On a levelised basis, the production process for FAME biodiesel is both less carbon-intensive and more cost-effective compared to HVO diesel.

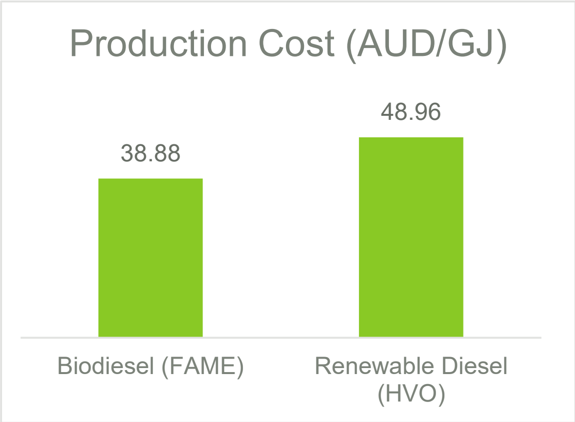
As discussed in the previous section, the FAME production process is less complex, while the additional process steps in hydrotreating the vegetable oil leads to more input energy.

The following chart set compares the levelised production cost and emissions associated with Biodiesel (FAME) and renewable diesel (HVO) using Used-Cooking Oil as the feedstock.

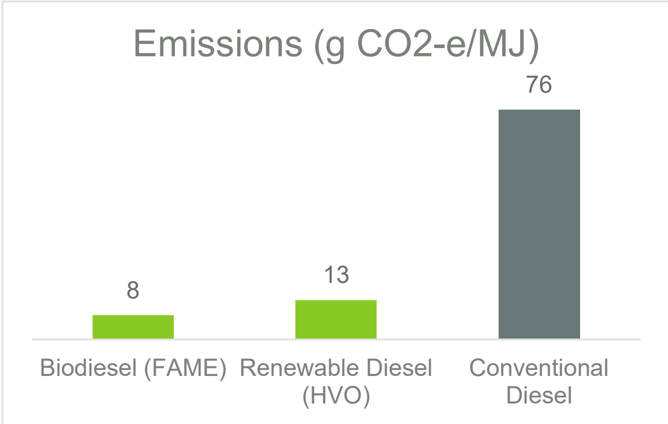
As indicated, FAME processing is a cheaper and more sustainable process.

Carbon emissions associated with conventional diesel refining and production depends greatly on region and method employed. An estimate of the fossil fuel emissions was derived from assuming production accounted for 80% of the emissions, which was the case for HVO and FAME.

The emission intensity for FAME and HVO processing can vary quite dramatically based on energy sources and their origin. For instance, the steam and electricity used for the HVO process is assumed to be fossil fuel derived, which could be substituted with a renewable energy source to lower emissions (Neste, for instance, use renewable energy sources at their Finnish refinery.). The hydrogen is also assumed to be grey, meaning produced from natural gas, which could be substituted with green hydrogen when it becomes more readily available.




**Levelised production cost comparison between FAME and HVO (AUD/GJ)**




**Levelised carbon emission intensity comparison between FAME and HVO (g CO2-e/GJ)**

**Figure 4-12 FAME and HVO levelised production cost and levelised emission intensity**

### Renewable diesel developments in 2022 / 2023

Renewable diesel offers alternate pathway opportunities in the biofuels space, given the extraordinary growth potential with major oil companies embracing the combination of Sustainable Aviation Fuels (SAF) and renewable diesel to future proof existing assets.

If this was to occur, the feedstock supply issues will need to see additions from corn or soybeans feedstocks, to include growing other oilseeds like canola and sunflower on a larger scale, importing other vegetable oils, or using other feedstocks such as beef tallow to produce renewable diesel fuel. Large steps are being taken in the US, Europe and South America.

Biomass feedstocks (eg spruce, corn stover and wheat straw) can also be used to replace petro-diesel through the production of renewable diesel and gasoline via fast pyrolysis and hydroprocessing technologies. The production costs of renewable diesel are proportional to the feedstock cost. The net energy ratios (NERs) of the process, which is the ratio of the energy content of the output product to fossil fuel inputs, also varies pending the level of preparation and logistics systems available for collection and supply to the processing site. Of the renewable resources, biomass is the most suitable to be directly converted to a liquid renewable fuel to replace fossil fuel. So, the holy grail is in finding a ‘waste’ or low value renewable feedstock that has already been harvested and can be automated for mechanical collection and transport.

It seems that the preferred pathway in the future for renewable diesel is to be produced from Hydrotreated Vegetable Oil (HVO), which is a drop-in fuel, with no engine modifications required. HVO fuel has chemical and physical properties like those of diesel fuel, however, its fossil-free composition and low carbon content differentiate it from diesel and make it attractive to those seeking a sustainable fuel option. HVO also has approximately 7% less fuel density, limited aromatic and sulphur content, and a higher cetane value versus diesel fuel. The disadvantage is the cost of production is currently higher than FAME based biodiesel.

The following figure shows a typical renewable diesel production process:

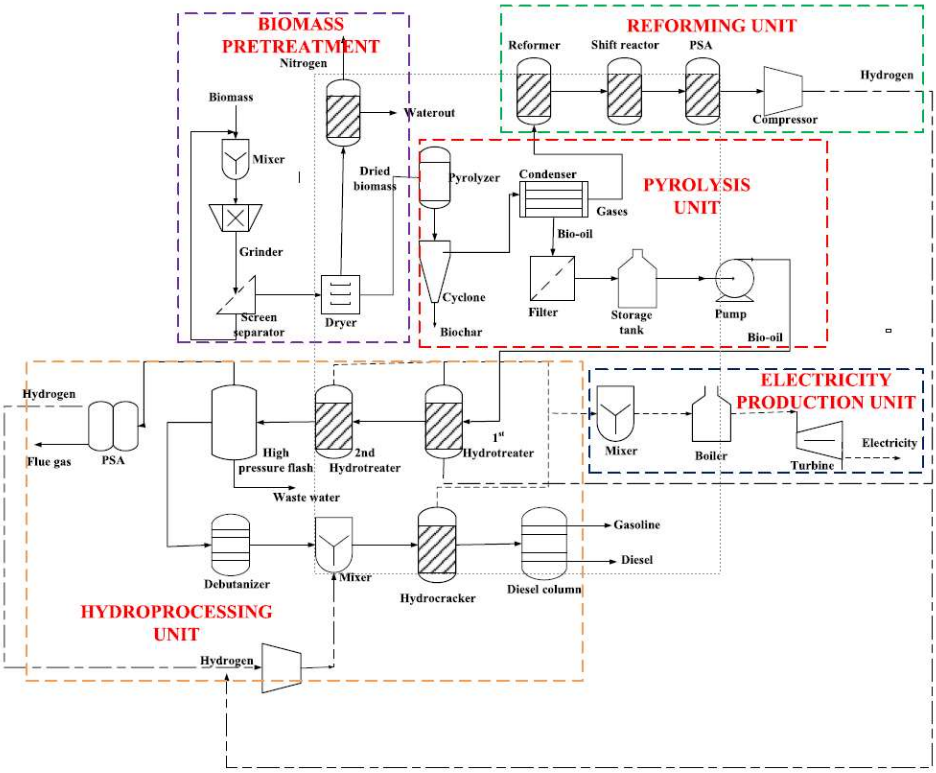



**Figure 4-13 Schematic process diagram of fast pyrolysis and hydroprocessing technology**

(Source: What is the production cost of renewable diesel from woody biomass and agricultural residue - Madhumita Patela, Adetoyese Olajire Oyeduna, Amit Kumara, Rajender Gupta)

Fast pyrolysis is a well-known thermochemical conversion technology that can convert solid biomass to an intermediate liquid product (bio-oil), gas, and biochar in the absence of oxygen and at a high heating rate. The bio-oil can be further upgraded to a transportation fuel through hydroprocessing technology to produce renewable diesel and gasoline. The properties of renewable diesel from biomass are similar to those of petro-diesel. Bio-oil quality and quantity are a function of feed-stock type, pyrolysis reactor, heating rate, and particle size distribution of the feed. Bio-oil yield varies by feedstock because of the differences in the chemical and elemental composition of biomass.

Researchers have studied various pyrolysis reactors such as fixed bed, bubbling bed, fluidized bed, cyclone bed, vacuum reactor, etc. Of the reactors, the fluidized bed reactor typically yields the most bio-oil because it allows for the right contact between biomass and the fluidizing medium.

The production cost of bio-oil and capital cost varies considerable based on the enabling infrastructure available for the feedstock supply chains and fuel offtake value chains. The differences in bio-oil production cost are due to feedstock type, biomass cost (harvesting and transportation cost), bio-oil yield, and pyrolysis plant capital cost. Biomass cost is location-specific and depends on yield, cultivation method, and transportation cost.

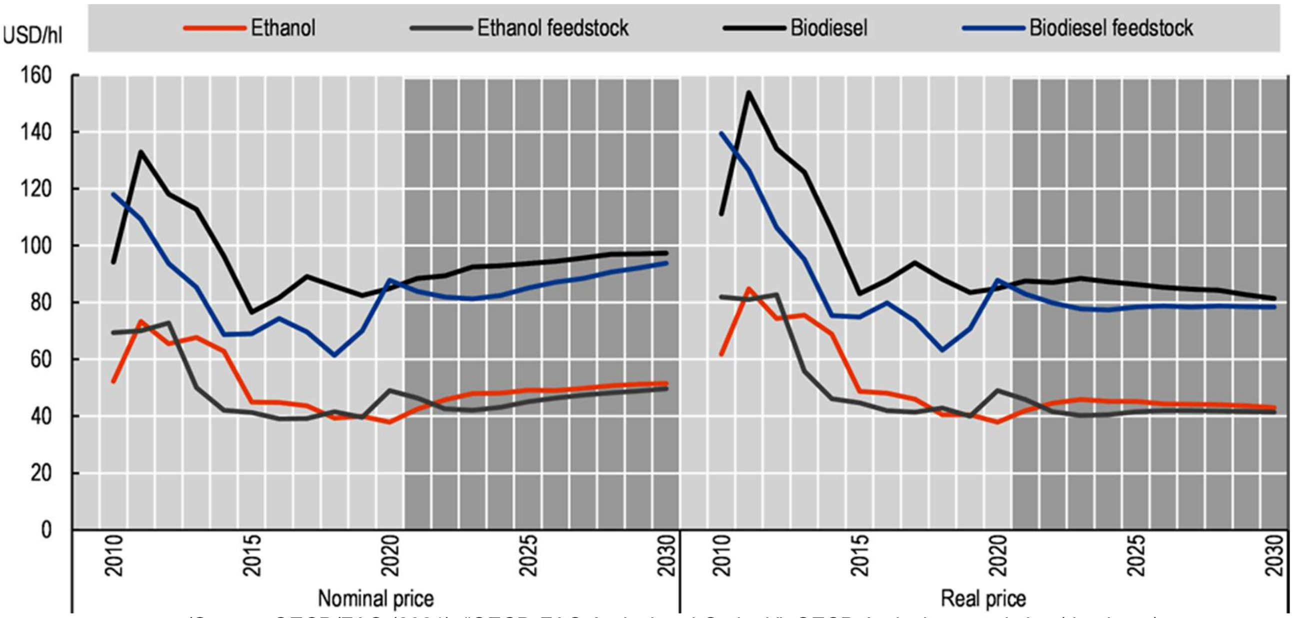
As such, it is difficult in the Australian context to have a 'typical' cost of production and capex cost for renewable diesel, that is comparable to FAME based biodiesel production from Used Cooking Oil (UCO), where a large part of the feedstock supply chain existed in the oils and fats markets.

Neste, the world's largest producer of renewable diesel and the top supplier in California, pointed out that subsidies are key in helping renewable diesel compete with conventional. In the markets where a state-level clean fuel program is available, the cost of Neste's renewable diesel is competitive with conventional diesel. Neste is currently producing more than 1 billion gallons of renewable products annually and is on track to increase its production capacity to 1.9 billion in 2023.

Also in the US, Oregon-based NEXT Renewable Fuels, which has partnered with Shell and BP on the project, anticipates annual production at 700 million gallons of renewable diesel. Wood waste in Oregon would be among the renewable materials used at the plant to create the fuel. Emissions reductions with renewable diesel have led California, Oregon and, most recently, Washington State, to include the fuel in their clean fuel programs, which provide subsidies that help lower costs for the fuel and create bigger demand especially at a time when petroleum-based fuels have reached historic prices.

## Recent trends on biofuels cost of production

The following figures show the correlation of the historical and predicted cost of global feedstock and biofuel prices.




(Source: OECD/FAO (2021), "OECD-FAO Agricultural Outlook", OECD Agriculture statistics (database), http://dx.doi.org/10.1787/agr-outl-data-en)

Notes:

Ethanol: wholesale price, US, Omaha; Biodiesel: Producer price, Germany, net of biodiesel tariff and energy tax. Real prices are nominal world prices deflated by the US GDP deflator (2020=1). As proxy for the biodiesel feedstock price, the world vegetable oil price is used and for ethanol a weighted average between raw sugar and maize is applied.

**Figure 4-14 The evolution of biofuel prices and biofuel feedstock prices**

## Australian biodiesel industry compared to global production

The Fuel Quality Standards Act 2000 of Australia defines Biodiesel as 'a diesel fuel obtained by esterification of oil derived from plants or animals.' Put simply, it is a fuel derived from plant and/or animal matter rather than petroleum sources. Biodiesel is currently a lot more prevalent than renewable diesel in Australia but has limitations in its use. It is produced from vegetable oils and waste fats. Any diesel engine can potentially run on a conventional biofuel blend and the Australian diesel fuel standard allows up to 5% biodiesel in pump fuel. Higher concentrations of conventional biodiesel can cause issues with current infrastructure and engines.

Renewable diesel is an advanced biofuel that is synthetically refined so it meets the fuel quality standard and therefore can be used as a direct replacement for petroleum diesel without the need to blend it with petroleum diesel. Renewable diesel is produced from a wider variety of feedstocks than conventional biodiesel including non-food biomass and feedstock such as straw, cotton trash and urban waste streams. It can also use purpose-grown crops such as grass, woody biomass or algae. Renewable diesel is compatible with existing infrastructure and vehicles, but commercial scale production has yet to occur in Australia, though some pilot scale plants are in operation.

The biodiesel market in Australia continues to struggle to make significant inroads into the diesel markets. This is due to low installed capacity, high feedstock prices and lack of incentives. Biodiesel producers have warned that Australia is over-reliant on the foreign fuel market and called for better investment and a positive policy shift towards domestic biodiesel. The push for a shift in policy also comes with the excise rate for domestic biodiesel currently over 19 per cent. That will gradually rise to 50 per cent in the year 2030 and beyond. The price of biodiesel blends will vary according to bulk supply prices for biodiesel and diesel and the effective excise on biodiesel blend fuels.

Australia's biodiesel is made from a range of feedstocks, primarily tallow and recycled vegetable oil. However, the global prices for oils and fats have increased, driving large export businesses that threaten the continuity of sustainable domestic feedstock left available in Australia.

Questions around storage and engine performance continually emerge that concern businesses interested in using biodiesel as a fuel. This is despite the fact that over 65 countries, including Australia, have developed or are developing renewable fuels policies that include biodiesel. With the latest government energy plans, national markets are encouraged by biodiesel's potential to help reduce carbon emissions from diesel fuel and its ability to improve fuel supply security. In many cases – not all – recurring questions about biodiesel are based on concerns which are unfounded, misinformed or just wrong. Global trials in using biodiesel in marine diesel engines and heavy haul transport have all be positive.

There are benefits of shifting to biodiesel included increased fuel security, by reducing reliance on global oil supply for refined fuel imports, supporting regional industrial development, and reducing carbon emissions. As Biodiesel is zero rated for carbon, it will reduce the carbon cost for those businesses that are liable. With the Government zero rating carbon from biodiesel there is an emission saving of 2.7kilograms of CO2 for every 1L of B100 Biodiesel used in place of Petroleum diesel. Biodiesel can play an important role towards our decarbonisation pathway for Australia's transport, construction activities and reducing emissions.

As an indication - for every 1,000,000L of B20 Biodiesel used, there is a reduction in CO2 emissions of 540 tonnes and 100% reduction in Sulphur emissions.

Biodiesel is environmentally sustainable over its entire life cycle of production and has major reductions in all greenhouse gas emissions. Exhaust emission reductions for Carcinogenic Compounds (95%); Carbon Monoxide (46%); unburnt hydrocarbons (35%) and Particulate Matter (45%). The production of Biodiesel has improved life cycle energy efficiency compared to Petroleum diesel.

The biodiesel industry wants the federal government to push other diesel-intensive sectors to make a shift to biodiesel, by cutting the diesel rebate scheme that benefits industries such as mining and agriculture and cost the taxpayer more than $7 billion in 2020-21.

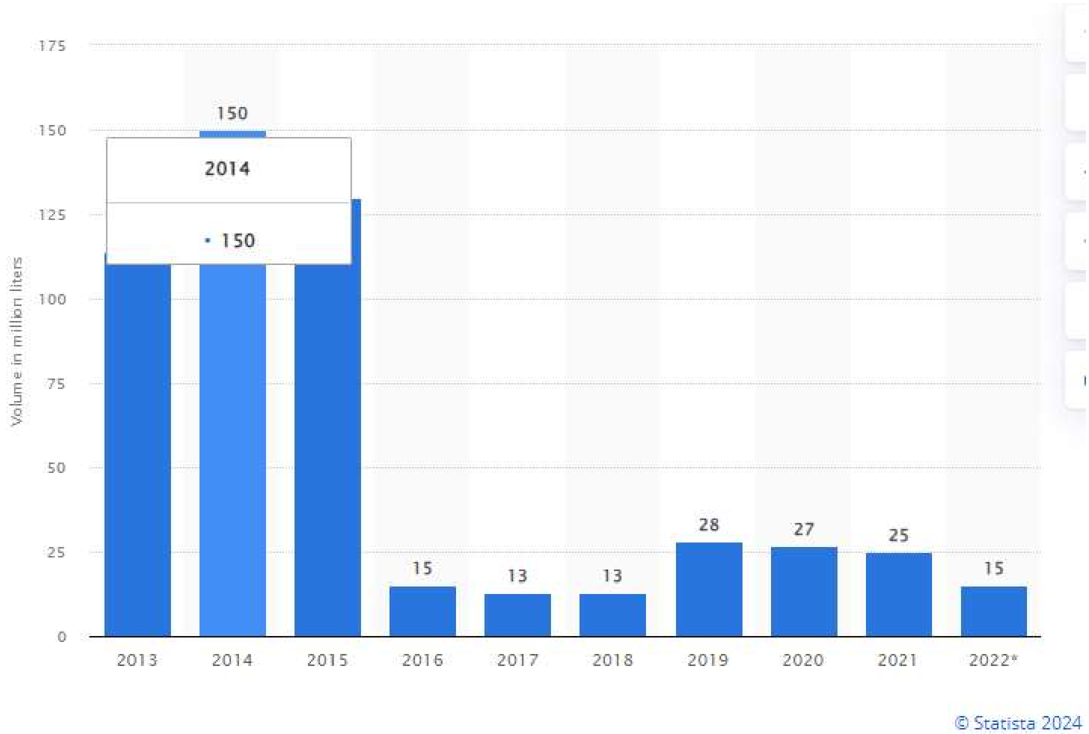



**Figure 4-15 Production volume of biodiesel in Australia from 2013 to 2022**

Australia's biodiesel production of 15 Ml per annum is small in comparison to other countries. According to a 2024 study, worldwide biofuel consumption is set to reach more than 224 million metric tons per annum by 2030. The United States is expected to remain the largest consumer of ethanol and biodiesel, at some 77 million metric tons. Fuel ethanol production is expected to climb to nearly 149 million metric tons by 2030. This would amount to an increase of more than 20 million metric tons compared with 2022 levels.

Ethanol is set to continue to be the most produced biofuel type, as biodiesel production volumes remain nearly half those of ethanol.

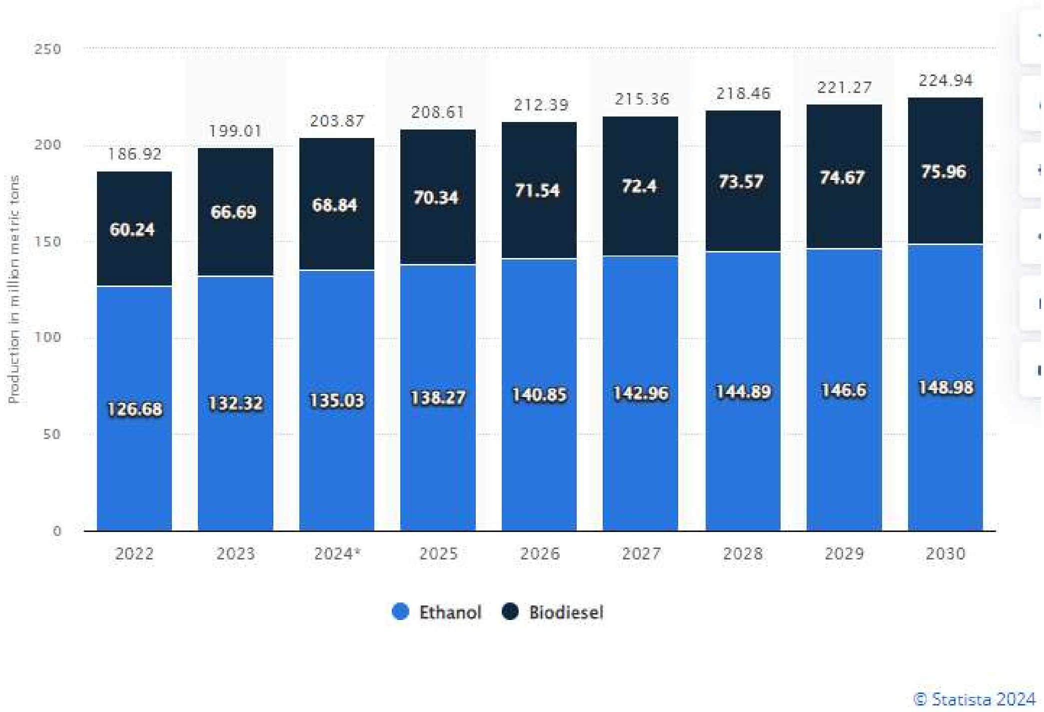



**Figure 4-16 Global production forecast volume of biofuels from 2022 to 2030**

## Current Australian example biodiesel projects

### Cargill canola crush plant and biodiesel facility, Kwinana WA

Lead Organisation Cargil.

Location Kwinana industrial strip, Western Australia.

Project currently in Study phase.

Cargill is investigating the potential to develop a world-class canola crush plant on a site adjacent to the CBH Kwinana Grain Terminal, subject to all necessary regulatory approvals. The project would service both the domestic and export oil and meal market, utilise locally grown canola and expand Western Australia's processing capacity for canola oil, as well supplying to the emerging biofuel market both in Australia and internationally. The combination of Cargill and CBH, the country's largest co-operative, could supply a biofuel production hub earmarked for BP's former oil import terminal at Kwinana. Cargill has been in discussions with several other parties regarding the potential crush plant facility in Kwinana WA, including CBH Group and how their existing supply chain may be able to support accumulation and export connections for the plant.

This is on top of the previous 2023 Cargill investment of US$50 million (A$73m) to upgrade and expand its Newcastle, Narrabri and Footscray oilseed crush facilities. These investments will help Cargill cater to the rising demand from customers for canola and cottonseed products and provide Australian farmers with further access to global markets.

Australian canola is in high demand globally for its use across food products, bio diesel and as a feed stock. With canola production on the rise, Cargill, a key supplier of high-grade canola oil to customers in Australia and Asia, is investing to expand its crush capacity and increase production of canola oil and meal as well as cottonseed oil and meal.

Source: Cargill investigates crush plant in WA | Cargill Australia

## Rio Tinto Biofuel Trial with Pongamia Feedstock

Lead Organisation: Rio Tinto.

Location Townsville, Queensland.

Project currently in Study phase.

Rio Tinto will develop Pongamia seed farms in Australia as part of a new biofuels pilot initiative.

The project will explore the potential of Pongamia seed oil as a feedstock for renewable diesel, a cleaner alternative to traditional fossil fuels. At the same time, the initiative aims to contribute to a new biofuel sector in Australia.

Rio Tinto is in the final stages of acquiring approximately 3000 hectares of cleared land near Townsville in north Queensland to establish farms to study growth conditions and measure seed oil yields. To deliver the project, Rio has partnered with Miday Limited, which will oversee the planting and management of the seed farms. Midway will engage with nurseries, agricultural experts and research organisations throughout the pilot, and prioritise opportunities for Traditional Owners and local communities. The Pongamia seed pilot is an important parallel pathway that could reduce our reliance on diesel in the mid-term.

However, Australia does not yet have a sufficient biofuel feedstock industry to meet domestic demands. The use of a native feedstock like pongamia can assist to scale-up sustainable biofuels industries to enhance the region's fuel security, create local economic opportunities, and contribute to emissions reductions targets.

Source: Rio Tinto launches biofuel trial in Australia - Energy Today (energytodaymag.com.au)

## Renergy energy from waste (biomass) through pyrolysis demonstration plant

Lead Organisation Renergi.

Location Collie, Western Australia.

Started March 2020.

Renergi marked the completed installation of its Collie plant in April 2023.

Trials to continue to late 2023.

$10m Total project cost.

The project involves the design, build and operation of a 1.5 tonne/hour pre-commercial demonstration energy-from-waste (EfW) plant located in the Shire of Collie in Western Australia. Technologies that convert inedible plant material (biomass) and municipal solid waste (garbage) into biofuels and biochar can help to reduce carbon dioxide emissions and improve energy security, while diverting waste from landfill. The EfW plant will use patented grinding pyrolysis technology (the Renergi Process) to convert an estimated 4000 tonnes per year of municipal solid waste, and 8000 tonnes per year of forestry wastes into crude pyrolysis/bio-oil for energy applications, and bio-char for land and other applications.

The demonstration plant was built at Collie in Western Australia's south-west corner, deploying Renergi's patented "grinding pyrolysis" process that converts organic materials into biochar, bio-gases and bio-oil by applying heat in an environment with limited oxygen. Renergi's innovative approach added metal grinding balls with the biomass into a spinning reactor vessel. Thousands of balls of various sizes help to break up the biomass during the 400 to 500 ºC pyrolysis process. Rather than pre-processing the organic feedstock, Renergi's system allows pyrolysis and grinding to occur simultaneously, reducing costs and saving energy.

This plant is co-located within the Shire's landfill site on Coalfields Highway, Collie East. This project will pioneer clean ways of chemically recycling municipal solid waste, including waste plastics, which would have otherwise ended up in landfill or waterways. The plant will help the Shire of Collie to achieve one of the highest waste diversion and recycling rates.

Installed in the Shire of Collie in Western Australia, Renergi's demonstration operation will produce bio-oil, biochar and wood vinegar. All have commercial value.

Bio-oil can be used to fuel electricity generation or refined to produce a renewable component of future aviation fuels, while biochar has many applications, from agriculture to construction.

## Just Biodiesel Pty Ltd Barnawatha BDI biodiesel plant

Lead Organisation Just Biodiesel Pty Ltd.

Location Barnawatha, Victoria.

Started Originally constructed in 2007, shutdown in 2016, re-established operations in 2018.

$50m original project cost in 2007.

The formation of Just Biodiesel Pty Ltd was finalised in December 2018. The Barnawatha BDI biodiesel plant was formerly owned by Australian Renewable Fuels (ARF) and Biodiesel Producers Pty Ltd (BPL). The plant had been shut down in 2016 due to poor margins and then went through successful re-commissioning and start-up phase, and restarted shipping biodiesel in the month of June 2019. The plant can potentially produce up to 50 million litres of biodiesel each year, including B5, B20 and B100 fuels.

Just Biodiesel started out with supply of biodiesel to the Australian market via their distribution partners Refuelling Solutions & Viva Energy Australia. However, in 2020 they were exporting the majority of our biodiesel to customers in the EU and California, having received ISCC & LCFS accreditation for our production process and quality standards. They have an integrated feedstock supply strategy for Tallow and Used Cooking Oil (UCO).

Just Biodiesel are witnessing a global shift in community expectations around renewable fuels, and as an active member of Bioenergy Australia, are well placed to meet these expectations.

**Figure 4-17 Just Biodiesel / refuelling solutions biodiesel plant, Barnawartha**

## Ecotech Biodiesel plant

Lead Organisation Ecotech Biodiesel.

Location Narangba, Queensland.

Started Originally constructed in 2006.

$50m original project cost in 2007.

The Ecotech Biodiesel production plant is located 35 kilometres north of Brisbane in Queensland, Australia. The facility can produce up to 30 million litres with room for a second facility to increase production to 75 million litres. The facility has been in operation since May 2006. They have an integrated feedstock supply strategy for Tallow and Used Cooking Oil (UCO).

Currently in Australia, a Fuel Standard only exists for a B5 blend, with special consideration being granted to some distributors who market a B20 blend. Over time more standards will be set which will eventually encompass a range of blends up to B100. Ecotech is currently supplying Biodiesel for use in B5, B20 and B100 vehicles and generators.

The state-of-the-art Ecotech plant uses sophisticated, world-class German technology which has been employed successfully in Europe since 2000. Ecotech through its subsidiary Bsmart Technology, has the license to sell the technology internationally.

Figure 4-18 Ecotech Biodiesel plant, Narangba, Queensland

## Biodiesel hypothetical project

Since the only current Australian biodiesel production in 2023 is through the Ecotech and Just Biodiesel facilities, which use a FAME biodiesel process fed by used cooking oil, or vegetable oils, the 2023 biodiesel hypothetical design assumes this configuration. The comparative costs of biodiesel and HVO renewable diesel still tips the process selection to the biodiesel design.

For the hypothetical project, the biodiesel feedstock goes through a process of transesterification; the fatty acid-rich feedstock is reacted with alcohol to form ethyl esters of fatty acids (biodiesel) and glycerol (glycerine). Energy or catalysts are used to drive the reaction and to increase the amount of output.

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in Australia in 2023 given, the previous discussion on typical options and current trends.

The hypothetical project is assumed to utilise the proven process of transesterification, methyl ester purification and glycerol recovery and purification to provide the lowest cost of production.

The assumed biodiesel project involves an assumed scope of work including:

- Generation type - Renewable Biofuel Production
- Fuel types - Vegetable Oils from soybean, sunflower, canola or safflower, Used Cooking Oil (UCO), Tallow, etc
- Capacity of 50 ML of biofuel
- Annual amount of biodiesel produced - 50 ML of biofuel and 7200 hours
- Plant construction cost of AUD $1.20 per litre of nameplate capacity
- Other variable input costs of AUD 83.2 cents per litre of biodiesel
- Total fixed costs of AUD 31.2 cents per litre of biodiesel
- Assume biodiesel will be sold into local fuel markets
- Site works and land
- Plant includes oilseed processing plant for a nominal 100,000 tonnes oil seeds
- Biodiesel Processing and Refining Facility
- Feedstock, water, process chemicals and biodiesel storage systems
- Utilities, fuel connections and balance of plant
- Oil seed meal handling and processing

The following table outlines the assumptions used for the hypothetical project.

**Table 4-43 Hypothetical biodiesel plant configuration and performance**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology | | FAME biodiesel process | Complete system involves oilseed processing of vegetable oils, pre-treatment, trans-esterification, biodiesel washing, biodiesel distillation, methanol recovery, oil seed meal processing, storage and handling |
| Feedstock source | | Vegetable oils | Vegetable Oils from soybean, sunflower or safflower, Used Cooking Oil (UCO), Tallow, etc |
| Make model | | Biodiesel OEM's | Integrated custom systems from biodiesel system suppliers and OEM's |
| Unit size (nominal) | ML | 50 ML Biodiesel | Biodiesel processing facility |
| Number of units | | 1 | Assume single facility |
| **Performance** | | | |
| Total plant size (Gross) | ML | 50 | Includes entire facility to make compliant biofuels |
| Biodiesel Production | ML | 50 | @ 7200 hours |
| Oil Seed Processing capacity | Tonnes | 100,000 | @ 7200 hours |
| Average Planned Maintenance/ Seasonal delays | Days / yr. | 65 | |

The following table lists to assumptions used to base the plant construction and design quality.

**Table 4-44 Project timeline**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Project timeline** | | | |
| Time for development | Years | 2 | includes pre/feasibility, design, approvals, procurement, etc. |
| First Year Assumed Commercially Viable for construction | Year | 2024 | |
| EPC programme | Years | 2 | For NTP to COD. |
| ▪ Total Lead Time | Years | 1 | Time from NTP to long lead items on site. |
| ▪ Construction time | Weeks | 52 | Time from site establishment to COD. |
| Economic Life (Design Life) | Years | 20 - 25 | Assuming corrosion resistant materials utilised |
| Technical Life (Operational Life) | Years | 30 | Assuming overhauls of CHP units at OEM intervals |

## Hypothetical biodiesel project cost estimates

Capital costs for biodiesel systems need to be presented with the entire value chain for the feedstocks used when preparing business cases. Where a facility can purchase a liquid feed like used cooking oil (UCO), tallow or vegetable oils, costs are transferred to OPEX and the overall capital cost is reduced to the main biofuel equipment. In regional installations incorporating the agriculture systems for oil seed processing, there is additional capital required for site infrastructure, logistics systems, storage and feedstock sorting and separation. As such the capital costs to install biodiesel production systems will be significantly greater than facilities where the feedstocks can be purchased from a local oils and fats market.

This hypothetical project is meant to be representative of an "average" plant constructed in Australia to process vegetable oils or UCO into biodiesel. There is certainly substantial variation in capacity, production efficiency, and feedstock that could be installed across the industry, and this should be kept in mind when viewing cost estimates from the example case.

With fuel supply issues from the wars in Ukraine and Israel / Palestine, Global Biodiesel prices are stabilising in the 2022 to 2023 period, reaching a typical figure in October 23 of AUD $2.00 per litre. Consequently, the feedstock cost for oils and fats also followed the fuel prices, making the margin for biodiesel production in Australia at a low level. Traditionally, by-product revenue from glycerin was only a few cents, but prices since 2021 also reached such a high level that it globally became a meaningful component of revenue for part of the year.

Capital and OPEX costs used in this 2023 assessment assume a biodiesel production facility including an oilseed crush facility in the front end to produce vegetable oils. The capital costs have been aggregated from OEM quotes and a nominal selection of associated infrastructure, plus an allowance for escalation due to market conditions. CPI and cost escalation are estimated to involve increases of 8% for this type of industrial equipment from 2022.

The main contributors to the CAPEX cost growth for building construction costs are due to ongoing skilled labour shortages, wage inflation and the passing through of manufacturing costs from energy intensive materials, recent price increases for electricity and freight and increasing fuel and operational costs.

The following table provides the cost parameters for the hypothetical biodiesel project as outlined above.

**Table 4-45 Hypothetical biodiesel project cost estimates**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX – EPC cost** | | | |
| Total Capital cost | $ | $60,000,000 | Total cost does not include land and development costs. |
| ▪ Equipment cost | $ | $24,000,000 | 40% of EPC cost – typical. |
| ▪ Installation cost | $ | $36,000,000 | 60% of EPC cost – typical. |
| **Other costs** | | | |
| Cost of land and development | $ | $6,000,000 | Assuming 10% of CAPEX. |
| Feedstock supply costs | $M | N/A | Typically, given the scale of the plant, the feedstock would be delivered by road. As such the fuel transport costs become an ongoing OPEX cost. |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / ML | $312,000 | Aggregated for scope listed above |
| Variable O&M Cost | $ / ML | $832,000 | Assuming current feedstock and energy prices |
| Annual Fixed O&M Cost | $ | $15,600,000 | Annual fixed cost for 50ML of production |
| Annual Variable O&M Cost | $ | $41,600,000 | Annual variable cost for 50ML of production |
| Total annual O&M Cost (Including Fixed + Variable) | $ | $57,200,000 | Annual fixed and variable cost for 50ML of production |

## 4.12 Waste to energy plants

### 4.12.1 Overview

Waste to Energy (WtE) plants use domestic waste or similar waste from industrial use following prevention, reuse and recycle to generate electricity and/or thermal energy (eg hot water or steam or both) by adopting strict environmental guidelines. The thermal energy is used for district heating (or cooling) purposes in homes, offices, hospitals, shopping complexes, etc. The electricity is exported to the grid. In this process the waste reduction is about 90%.

The flue gas cleaning system of today's WtE plants use the strictest emission values prescribed in EU Directive (2010/75/EU).

A significant portion of municipal waste is biodegradable and is considered to be biomass.

The main advantages of waste to energy plants include:

- Reduces landfill requirement
- Energy recovery from non-recyclable waste
- Reduces greenhouse gas emission due to elimination of methane generation in landfill (greenhouse gas potential of methane is 21 times higher than that of $CO_2$)
- Renewable energy generation
- About 90% overall waste reduction.

The technologies behind today's WtE plants are described briefly below.

### 4.12.2 Mass burn technology (incineration of waste)

Around forty percent of total WtE plants in the world use grate boiler technology. This is also known as mass burn technology. Municipal Solid Waste (MSW) is delivered in trucks to a pit inside the plant. Overhead cranes equipped with grapples pick up waste from the pit and feed it to the boiler. MSW is fed to the boiler grate in a controlled way via the inlet chute. The air for combustion is supplied through holes in the grate and nozzles placed at the top of the grate in the combustion zone. The waste burns as it moves along the grate. The thermal energy is extracted in the boiler to generate steam which is fed to the steam turbine generator to produce electricity.

The flue gas is cleaned using scrubbers, activated carbon, catalytic reactors, and bag filters/electro-static precipitators for the removal of $NO_x$, $SO_x$, acids, Hg and particulates respectively. Plants in Europe using this technology meet the strictest environmental requirements of EU Directive 2010/75/EU.

### 4.12.3 Gasification of waste

Gasification is a process that transforms any carbon-based material such as MSW into a gas by creating a chemical reaction without burning the material. This reaction combines those carbon-based materials, known as feedstocks, with small amounts of air or oxygen to produce primarily a mixture of carbon monoxide and hydrogen. Additional treatment is required to remove any pollutants and or impurities. The gas produced is called "synthesis gas" or "syn gas". The temperature at which gasification occurs varies between 600°C to 1,000°C. Fuel is usually shredded before it is fed into the gasifier.

In a gasification based WtE plant, syn gas is burnt either in a reciprocating engine or gas turbine to directly produce electricity, or via burners in a boiler to produce hot water or steam to generate electricity. Gasification is not incineration, rather production of syn gas which is then burnt in a controlled atmosphere to produce thermal energy.

### 4.12.4 Combustion of refuse derived fuel (RDF) in boilers

Refuse derived fuel (RDF) is prepared from MSW after removing non-combustibles (eg glass and metal) using an air knife or similar density separation technique and magnetic separation. The moisture is also removed to less than 15%. The removal of non-combustibles and moisture increases the calorific value of waste as a fuel. It is then shredded to a size less than 25 mm as a final RDF fuel for cofiring in either a conventional boiler with another fuel (eg coal) or for combustion in a moving grate stoker boiler or in a fluidised bed combustion boiler with no other fuel. An RDF processing plant is located close to an MSW receiving station.

### 4.12.5 Recent trends

There are more than 2000 operating WtE plants worldwide. They are mostly located in countries with large population density and having not enough real estate for landfill, such as countries in Europe, China, Japan, Taiwan, Singapore etc.

Australia does not have any operating waste to energy plants. However, two plants are currently under construction/commissioning in Western Australia as listed below. However, there are also a number of other projects at various stages of development.

- Kwinana Waste to Energy (Kwinana, WA): The plant is currently under construction. Acciona has acquired 100% ownership of the plant in an agreement reached with Macquarie Capital and Dutch Infrastructure Fund. There have been delays during construction and the plant is expected to be commissioned in the last quarter of 2024. The plant will process approximately 460,000 tonnes of municipal waste per annum and generate about 38 MW of base load electricity. The project has received ARENA funding.
- East Rockingham (Perth, WA): This Clean Energy Finance Corporation and ARENA funded project is expected to be operational by the end of 2024 following considerable delays during construction. Western Power has completed the energisation of the switchyard in 2022. The plant will process up to 300,000 tonnes of MSW per annum and generate approximately 28.9 MW of electricity. The project capital cost is approximately $511 million.

**Figure 4-19 Kwinana Waste-to-Energy project, Kwinana WA**

### 4.12.6 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024 given the above discussion on typical options and current trends.

**Table 4-46 Configuration and performance**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology | | Sub-critical boiler | Incineration (mass burning) with reciprocating grate and mechanical draft cooling tower. |
| Fuel source | | Municipal waste | |
| Make model | | Western OEM | |
| Unit size (nominal) | MW | 30 | |
| Number of units | | 1 | |
| Steam Pressure | MPa | 7 | |
| Steam Temperature | °C | 470 | |
| Condenser pressure | kPa abs | 7.2 | |
| **Performance** | | | |
| Total plant size (Gross) | MW | 30 | 25°C, 110 metres, 60%RH |
| Auxiliary power consumption | % | 12% | |
| Total plant size (Net) | MW | 26.4 | 25°C, 110 metres, 60%RH |
| Seasonal Rating – Summer (Net) | MW | 25.7 | 35°C, 110 metres, 60%RH |
| Seasonal Rating – Not Summer (Net) | MW | 26.8 | 15°C, 110 metres, 60%RH |
| Heat rate at minimum operation | (GJ/MWh) HHV Net | 19.940 | 25°C, 110 metres, 60%RH |
| Heat rate at maximum operation | (GJ/MWh) HHV Net | 15.388 | 25°C, 110 metres, 60%RH |
| Thermal Efficiency at MCR | %, HHV Net | 23.4% | 25°C, 110 metres, 60%RH |
| **Annual Performance** | | | |
| Average Planned Maintenance | Days / yr. | 22.8 | |
| Equivalent forced outage rate | % | 4% | |
| Annual capacity factor | % | 89.8% | |
| Annual generation | MWh / yr. | 207,675 | Provided for reference based on assumed capacity factor. |
| Annual degradation over design life - output | % | 1-2% for first 18 months and then flat/low level degradation | |
| Annual degradation over design life – heat rate | % | 0.2% | Assuming straight line degradation. |

Table 4-47 Technical parameters and project timeline

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Technical parameters** | | | |
| Ramp Up Rate | MW/min | 1.2 | Based on 3%/min standard operation |
| Ramp Down Rate | MW/min | 1.2 | Based on 3%/min standard operation |
| Start-up time | Min | Cold: 420<br>Warm: 120<br>Hot: 60 | Standard operation. |
| Min Stable Generation | % of installed capacity | 40% | Without oil support |
| **Project timeline** | | | |
| Time for development | Years | 3-4 | includes pre/feasibility, design, approvals, procurement, etc. |
| First Year Assumed Commercially Viable for construction | Year | 2024 | |
| EPC programme | Years | 3 | For NTP to COD. |
| ▪ Total Lead Time | Years | 1.75 | Time from NTP to steam turbine on site. |
| ▪ Construction time | Weeks | 65 | Time from steam turbine on site to COD. |
| Economic Life (Design Life) | Years | 30 | |
| Technical Life (Operational Life) | Years | 50 | |

### 4.12.7 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-48 Cost estimates

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX – EPC cost** | | | |
| Relative cost | $ / kW | 25,512 | Net basis. Relative cost does not include land and development costs. |
| Total EPC cost | $ | 673,542,000 | |
| ▪ Equipment cost | $ | 404,125,000 | 60% of EPC cost – typical. |
| ▪ Installation cost | $ | 269,417,000 | 40% of EPC cost – typical. |
| **Other costs** | | | |
| Cost of land and development | $ | 60,618,000 | Assuming 9% of CAPEX. |
| Fuel connection costs | $M | N/A | Typically, given the scale of the plant, the waste would be delivered by road. As such the waste transport costs become an ongoing OPEX cost. |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / MW (Net) | 235,556 | |

| Item | Unit | Value | Comment |
|---|---|---|---|
| Variable O&M Cost | $ / MWh (Net) | 13.79 | Excludes fuel cost. Fuel cost is dependent on project and site with respect to fuel supply source location. However, fuel cost is anticipated to at least include the handling and delivery cost to site. Avoided disposal cost savings would need to be negotiated for the individual project. |
| Total annual O&M Cost | $ | 9,083,991 | |

# 5 Hydrogen Based Technologies and Storage

## 5.1 Overview

The following sections provide the technical and cost parameters for each of the nominated hydrogen-based technologies and storage, along with a brief discussion of typical options and recent trends. The information in the respective tables has been used to populate the AEMO GenCost 2024 Excel spreadsheets, which are included in Appendix A.

## 5.2 Reciprocating engines

### 5.2.1 General

Refer to Section 4.7.

## 5.3 Gas turbines, including hydrogen conversion of gas turbines

### 5.3.1 General

Refer to Section 4.9.

## 5.4 Electrolysers

### 5.4.1 Overview

The interest in hydrogen as part of the energy mix has increased dramatically in the past few years, as hydrogen offers a potential pathway to a low carbon future when produced using renewable power generation sources. Once produced, hydrogen can then be stored and/or transported either via pipeline, for domestic use, or ocean-going vessel (including as ammonia) for international export. Currently hydrogen is seen as a potential zero emission transport fuel, alternative fuel for iron and steel production, ammonia production, or for potential blending with natural gas in existing gas pipelines.

### 5.4.2 Typical options

Hydrogen is typically produced either by electrolysis of water, or by a thermochemical process which uses fossil fuels. Currently, the majority of hydrogen production is by thermochemical process, although renewable hydrogen—*using water electrolysis and electricity generated by renewable sources*—is gaining momentum.

For this Section 5.4, the focus is the production of hydrogen through a zero-emission electrolysis process. For this there are two primary technology options, being:

- Alkaline electrolysis – a mature electrolyser technology based on submersed electrodes in liquid alkaline electrolyte solution. This technology has long been used in the production of chlorine where hydrogen is produced as a by-product
- Proton Exchange Membrane (PEM) – a less mature electrolyser technology categorised by its semipermeable polymer electrolyte membrane which separate the electrodes.

Designs vary from supplier to supplier but in most cases electrolysers are made up from a number of individual cells or stacks of cells manifolded together for a combined output. Multiple cells are combined into stacks and stacks then combined into modules. Currently electrolysers can be supplied in individual modules ranging from single digit MWs up to 20 MW. In larger facilities a number of modules are combined and used to meet the demand with an element of shared utilities.

### 5.4.3 Recent trends

There are relative benefits of the various technologies and from individual supplier to supplier. Where large industrial scale applications are being proposed the capex cost advantage of low-pressure systems are being maximised and this can be seen from both PEM and Alkaline suppliers.

Several examples of grid services applications are being published globally. The 10 MW PEM electrolyser Shell are installing at their Rhineland Refinery[45], achieving start-up in July 2021 as Europe's largest PEM electrolyser in operation, will provide grid stabilisation services and findings from E.ON show alkaline technology has potential for this also[46]. The role of hydrogen production using electrolysers to provide system services to the NEM is also being studied[47] .

The world's largest PEM electrolyser plant in operation at 20 MW is installed at the Air Liquide hydrogen production facility in Bécancour, Quebec[48]. The world's largest alkaline electrolyser plant being commissioned in 2023 is China's 260 MW Kuqa facility[49].

Globally the trend in electrolysis is to the larger scale, with more projects now planned to be developed at the 100 MW+ scale. Some developments in the GW scale also being considered. Electrolyser OEMs are building giga-factories for the increased manufacturing production of electrolyser capacity requirements expected globally. Recent research by BloombergNEF notes that factories around the world could produce up to 31.7GW of electrolysers per year at the end of 2023, nearly 17 times what was delivered that year and more than seven times the capacity expected to be delivered in 2024 leading to severe overcapacity of manufacturing[50].

For hydrogen production, PEM electrolysers have grown in popularity relative to more traditional Alkaline technology. This is primarily due to the improved dynamic operation of the PEM-based technology, with improved responsiveness, and improved current densities.

PEM typically also produces hydrogen at around 30 bar compared to atmospheric pressures typically achieved with alkaline electrolysers which reduces the need for costly first stage compression depending on end use transportation and application requirements, although some OEMs can offer PEM units with hydrogen delivered at atmospheric pressure.

The Australian Government has recently released its 2024 National Hydrogen Strategy providing the framework to guide Australia's production, use and export of hydrogen, as a focused update from the 2019 release.[51]. The Hydrogen Headstart Program administered by ARENA includes Round 1 shortlisted projects receiving development funding support as listed below, with a Round 2 recently announced:

H2 Kwinana, WA – 105 MW electrolyser size for hydrogen production for ammonia end use

HIF Tasmania, eFuel Facility – 144 MW Electrolyser size for hydrogen production for e-fuels end use

Port of Newcastle Green Hydrogen Project, NSW – 750 MW Electrolyser size for ammonia end use

Hunter Valley Hydrogen Hub, NSW – Phase 1 (50 MW) / Phase 2 (200 MW) Electrolyser size for ammonia and mobility end use

Central Queensland Hydrogen Project, QLD – 720 MW Electrolyser size for ammonia end use

[45] https://www.fch.europa.eu/news/launch-refhyne-worlds-largest-electrolysis-plant-rhineland-refinery

[46] https://www.eon.com/en/about-us/media/press-release/2020/2020-06-30-e-on-and-thyssenkrupp-bring-hydrogen-production-on-the-electricity-market.html

[47] https://www.aemc.gov.au/hydrogen-role-hydrogen-production-industry-providing-system-services-nem

[48] https://www.energize.co.za/article/hydrogen-technology-powers-worlds-largest-pem-electrolyser#:~:text=Cummins%20recently%20provided%20a%2020%20MW%20proton%20exchange,over%E2%80%AF3000%20t%20of%20hydrogen%20annually%20using%20clean%20hydropower

[49] https://www.hydrogeninsight.com/production/world-s-largest-green-hydrogen-project-chinas-260mw-kuqa-facility-to-be-commissioned-at-the-end-of-may/2-1-1457242

[50] https://www.hydrogeninsight.com/electrolysers/severe-overcapacity-the-global-supply-of-electrolysers-far-outstrips-demand-from-green-hydrogen-projects-bnef/2-1-1618327

[51] https://www.dcceew.gov.au/energy/publications/australias-national-hydrogen-strategy

Murchison Hydrogen Renewables Project, WA – 1625 MW Electrolyser size for ammonia end use

The Australian Government has also invested more than $500 million to support the development of hydrogen hubs in regional Australia.

In the 2024–25 Budget, the Australian Government announced a Hydrogen Production Tax Incentive to support the production of renewable hydrogen from 2027–28 to 2039–40. The $2 per kilogram Hydrogen Production Tax Incentive provides time-limited, demand-driven production support to eligible producers of renewable hydrogen through Australia's tax system, forming the basis of government support to the sector to 2040.

Australian and German Governments have recently agreed to expand their existing Energy Partnership to an Energy and Climate Partnership meaning Australia will have the opportunity to export hydrogen to some of the world's largest renewable hydrogen markets, including Germany. This establishes new green supply chains, supporting a Future Made in Australia.[52].

Some recent larger scale planned developments (100 MW+) to be operational at the earliest in 2026, and to 2030 (subject to feasibility and financial investment decision depending on project) include:

- Fortescue Future Industry (FFI's) Gibson Island Green Hydrogen Project for conversion into green ammonia at existing facility, Queensland (500 MW electrolyser plant planned, now in FEED stage)
- South Australian Hydrogen Jobs Plan – development of a 250 MW electrolyser plant in Whyalla, South Australia (under development)
- ABEL Energy Bell Bay Powerfuels Project, Tasmania (100 MW) (due to commence FEED study)
- H2-Hub Gladstone Queensland (up to 3 GW in stages) (development stage).

It is important to note that the choice made between PEM and Alkaline electrolyser technologies is project specific with both having a role to play in the current market. Generally speaking, Alkaline electrolyser technology is lower in cost compared to PEM. Electrolyser plant equipment capex from Chinese Alkaline suppliers can be up to 50% cheaper when compared to Western suppliers, based on market activity on renewable hydrogen development projects in Australia. However, this cost benefit for Chinese Alkaline suppliers may be reduced when considering quality of manufacture and standards of compliance in other countries including Australia

Although PEM is seen as more responsive and/or flexible, improvements have been made with the latest Alkaline electrolysers which has closed the gap in some areas and offers improved benefits in others (such as reduced water consumption and footprint). The requirement for responsiveness benefit should be assessed against the electrolyser application (eg FCAS services) whilst being able to operate reliably using a variable renewable energy supply.

### 5.4.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a current plausible project for installation in the NEM pending commercial feasibility as a number of modules combined together with shared balance of plant to achieve a 100 MW+ scale electrolyser plant, given the above discussion on typical options and current trends based on the 2024 status for this report. The performance data provided in Table 5-1 is based on a 10 MW module.

**Table 5-1 Electrolyser configuration and performance (per 10 MW module, total plant size of 500MW)**

| Item | Unit | PEM | Alkaline | Comment |
|---|---|---|---|---|
| **Configuration** | | | | |
| Technology | | Proton Exchange Membrane | Alkaline | |

[52] https://www.dcceew.gov.au/about/news/australia-germany-strengthen-cooperation-energy-climate#:~:text=Australian%20and%20German%20Governments%20have,zero%20transition%20and%20energy%20security.

| Item | Unit | PEM | Alkaline | Comment |
|---|---|---|---|---|
| Unit size (nominal) | MW | 10 | 10 | Selected based on the range of currently available single stack sizes (or combined as stack modules) |
| Number of modules | | 50 | 50 | |
| Total plant size | MW | 500 | 500 | Net of auxiliaries |
| **Performance (10 MW module)** | | | | |
| Auxiliary power consumption | % | ~5% | ~5% | Excludes compression. Depends on manufacturer, cooling system, etc |
| Seasonal Rating – Summer (Net) | MW | 10 | 10 | Derating not expected at 35°C. Will be dependent on cooling system design. |
| Seasonal Rating – Not Summer (Net) | MW | 10 | 10 | |
| Efficiency | % | 65.7% | 71.7% | HHV basis - Beginning of Life |
| Efficiency | kWhe/kg $H_2$ | 60 | 55 | Typical (whole package), excluding additional compression (shown below). Varies with OEM |
| Hydrogen production rate | kg/h | 167 | 181.8 | |
| Output pressure | bar | ~ 30 bar | Atmospheric | Typical |
| Additional compression power | kW | 125 | 485 | Additional power required to compress hydrogen to 100bar (compression for downstream process) |
| Life cycle design | hrs | 80,000 | 80,000 | Represents typical expected life of cells only. Cells can be refurbished or replaced within the unit to achieve plant life of around 25 years. Some variance across OEMs. |
| Water consumption | L/kg$H_2$ | 13-15 | 13 - 15 | Typical raw water consumption volumes, for hydrogen production only (based on air cooled system).<br>Quantity of rejected water will vary according to original water quality. Typically, PEM technology requires a high quality of water to enter the cells and as such more water is rejected in the purification step. |
| **Annual Performance** | | | | |
| Average Planned Maintenance | Days / yr. | <15 | 15 | Includes consideration for mid-life stack replacement on average annual basis. |
| Equivalent forced outage rate | % | 3% | 3% | |
| Annual degradation | % | 1 | 1 | Increase in specific energy over time to produce same amount of hydrogen. Typical published value. |

Table 5-2 Technical parameters and project timeline

| Item | Unit | PEM | Alkaline | Comment |
|---|---|---|---|---|
| **Technical parameters** | | | | |
| Ramp Up Rate | | 10-100%/sec | 20%/minute | PEM typically 10%-100%/sec. Alkaline typically 20%/minute. Some Alkaline OEMs have faster rates (eg 20% per 6 sec) |
| Ramp Down Rate | | 10-100%/sec | 20%/minute | PEM typically 10-100%%/sec. Alkaline typically 20%/minute. Some Alkaline OEMs have faster rates eg 20% per 6 sec) |
| Start-up time | Min | Cold: 5<br>Warm: 0.5 | Cold: 60<br>Warm: 1 | Quoted start up time varies from vendor to vendor, however typically PEM technology advertises faster start-up particular in the cold start-up case |
| Min Stable Generation | % of installed capacity | 10% | 10% | PEM electrolyser turndown ability is quite specific to suppliers.<br><br>For rapid response, the electrolyser would likely need to be in a hot standby or minimum turndown and as such not turning off the load completely.<br><br>Typically, minimum turndown for PEM modules can range from 5-15%, with Alkaline modules ranging from 10-20% depending on OEM and unit module size. Lower overall plant minimum turndown is possible by combining multi-module configurations in larger MW scale plants if some modules are turned off. However, this is at the consequence of the fast responsive capacity being only available from those modules kept in hot standby or service. |
| **Project timeline** | | | | |
| Time for development | Years | 2.5 | 2.5 | Includes pre/feasibility, design, approvals etc. |
| First Year Assumed Commercially Viable for construction | Year | 2024 | 2024 | Although theoretically viable at this size in 2024, a hydrogen offtake agreement would need to be secured for this volume and at a price that would result in a commercially viable project with government funding support as required (the market will determine this). |
| EPC programme | Years | 2-3 | 2-3 | For NTP to COD. 100 MW+ plant |
| ▪ Total Lead Time | Years | 2 | 2 | Time from NTP to main equipment on site. |
| ▪ Construction time | Weeks | 26 | 26 | Time from main equipment on site to COD |
| Economic Life (Design Life) | Years | 10 | 10 | Assumed time to membrane replacement based on 91.3% capacity factor. If powered purely by renewables capacity factors will be lower. |
| Technical Life (Operational Life) | Years | 25 | 25 | Typical value. |

### 5.4.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above considered as a 100 MW+ size (multiple 10 MW modules arrangement), however the costs are representative of the technology type rather than the specific vendors and models as per above.

Larger scale plants are now under development (100 MW+) in Australia, however, are yet to reach financial investment decision. Pricing variability is seen in the Australian market on projects based on their stage of development, OEM suppliers used, contractor risk premium and margin.

The cost of producing and installing electrolysers for green hydrogen production in China, the US and Europe has risen by more than 50% compared to 2023, research house BloombergNEF (BNEF) has found, rather than the gradual reduction its analysis had previously indicated, mainly due to inflation of materials and labour for Western manufacturers. Delays to international government subsidies have also slowed the scale-up of green hydrogen projects, meaning that electrolyser manufacturers are unable to benefit from economies of scale, resulting in higher prices for longer[53].

This cost increase trend for 2024 from 2023 figures is also being experienced in Australia for large scale 100MW+ projects.

The change from 2023 to 2024 reports have been an increase to the MW size of the hypothetical project from 100 to 500 MW. The market has seen a price increase in electrolyser project costs, however, there is also a scale benefit in the 2024 report cost. The net result in the 2024 report is a cost reduction due to the scale benefit exceeding the cost increase for same MW size electrolyser plant.

The accuracy of pricing is challenging and increases in original projects estimates are also being seen by some developers. Hence, these aspects should be noted for the cost estimate provided. Actual costs for a specific Project should be confirmed based on scope, engineering, and market engagement for pricing.

**Table 5-3 Cost estimates (>100 MW – 1,000 MW plant)**

| Item | Unit | PEM | Alkaline | Comment |
|---|---|---|---|---|
| **CAPEX – EPC cost** | | | | |
| Relative cost | $ / kW | 2,630 | 2,460 | Full EPC turnkey (Total Installed Cost) based on 500MW plant size. Relative cost does not include power generation, land and development costs. PEM range ($2,460-$2,770/kW), Western supply and varies based on OEM. Chinese supply Alkaline and PEM not included in cost range. Lower costs for Chinese supply have been reported up to 50% lower. |
| Total EPC cost | $ | 1,315,000,000 | 1,230,000,000 | Based on 500 MW plant basis. Total cost does not include power generation and transmission, pipelines, hydrogen storage and compression. Total EPC cost does not include land and other owner's costs. |
| ▪ Electrolyser package cost | $ | 531,000,000 | 455,000,000 | Electrolyser package supply cost – typical. |

[53] https://www.hydrogeninsight.com/electrolysers/cost-of-electrolysers-for-green-hydrogen-production-is-rising-instead-of-falling-bnef/2-1-1607220

| Item | Unit | PEM | Alkaline | Comment |
|---|---|---|---|---|
| ▪ BOP & Construction cost | $ | 784,000,000 | 775,000,000 | BOP and construction cost – typical. Excludes compression and storage. |
| **Other costs** | | | | |
| Cost of land and development | $ | 105,200,000 | 123,000,000 | Based on 8-10% of CAPEX. |
| Fuel connection costs | $ | N/A | N/A | |
| Hydrogen compressor | $ | 24,300,000 | 94,300,000 | Supply and install cost (3 x 33% of total hydrogen production flow; see Table 5-1 for pressure basis) |
| Hydrogen transport | $/km | $475,000/km | $475,000/km | DN150 buried pipeline (suitable for 1 x 100 MW unit). Multiple lines for plant size, or larger line size (cost not estimated) |
| **OPEX – Annual** | | | | |
| Fixed O&M Cost | $ / MW (Net) | 52,600 | 49,200 | Based on 2% of CAPEX per annum. Note that this includes allowance for the 10 year stack overhaul. Stack overhaul cost is based on current costs.<br>Excludes power and water consumption costs. |
| Variable O&M Cost | $ / MWh (Net) | | | Included in fixed O&M component. |
| Total annual O&M Cost | $ | 26,300,000 | 24,600,000 | Annual average cost over the design life. Excludes power and water consumption costs. |

## 5.5 Hydrogen fuel cells

### 5.5.1 Overview

Hydrogen can be used for a variety of uses including natural gas blending, ammonia production, and mobility applications. Fuel cells for stationary power generation are also being considered to provide a carbon emission free solution for continuous and backup electricity generation.

Currently only a small percentage of hydrogen-based projects involve fuel cells for stationary power generation applications and are generally currently applied to small mostly off-grid (or behind the meter) installations supporting back-up power for homes, businesses, remote communities, universities, datacentres, and hospitals.

### 5.5.2 Typical options

Below are some of the most commonly used fuel cells[54]:

- Proton Exchange Membrane Fuel Cell (PEMFC): PEMFCs use a polymer membrane for their electrolyte and a precious metal, typically platinum, for their catalyst. PEMFCs operate between 40% to 60% efficiency and are capable of handling large and sudden shifts in power output
- Direct Methanol Fuel Cells (DMFCs): DMFCs also use a polymer membrane as an electrolyte and commonly a platinum catalyst as well. DMFCs draw hydrogen from liquid methanol instead of using hydrogen directly as a fuel

[54] http://www.fchea.org/fuelcells

- Alkaline Fuel Cell (AFC): AFCs use porous electrolytes saturated with an alkaline solution and have an alkaline membrane. AFCs have approximately 60% electrical efficiency
- Phosphoric Acid Fuel Cell (PAFC): PAFCs use a liquid phosphoric acid and ceramic electrolyte and a platinum catalyst. They have similar efficiencies to those of PEMFCs. PAFCs are often seen in applications with a high energy demand, such as hospitals, schools, and manufacturing and processing centres
- Solid Oxide Fuel Cell (SOFC): SOFCs operate at high temperatures and use a solid ceramic electrolyte instead of a liquid or membrane. SOFCs are used in large and small stationary power generation and small cogeneration facilities.

Stationery fuel cell stack sizes vary from kWs to 3 MW. Modular power blocks of 1-2 MW sizes are available from PEM fuel cells suppliers such as Accelera and Ballard and can be combined to develop larger MW scale plants.

Fuel cell installations being developed are offered as a containerised modular solution and can either be provided as standalone plants or installed in combination with other power (eg Rooftop PV) or energy storage (eg Lithium battery) solutions.

### 5.5.3 Recent trends

For stationery fuel cells the uptake has been growing rapidly worldwide, with installed capacity reaching 1.6 GW in 2018. However, only a small portion (approximately 70 MW) is fuelled by hydrogen[55].

Some of the largest technology companies including Apple, Google, IBM, Verizon, AT&T, Microsoft and Yahoo have all recently installed small scale (kW scale) stationery hydrogen fuel cells with some developing MW scale installations as a source of power for their operations.

In 2020, Hanwha Energy commissioned the largest industrial hydrogen-fuel-cell power plant in the world, at the time which was also the first to use only hydrogen recycled from petrochemical manufacturing. The 50-MW plant is located at the Daesan Industrial Complex in Seosan, South Korea[56].

NREL has collaborated with Toyota Motor North America (Toyota) through a cooperative research and development agreement to build, install, and evaluate a 1-megawatt (MW) proton exchange membrane (PEM) fuel cell power generation system at NREL's Flatirons Campus[57]. Toyota Australia has signed contracts with French sustainable energy solutions provider EODev (Energy Observer Developments) to assemble and distribute its stationary hydrogen fuel cell power generators GEH2® (110kW) in Australia commencing in 2024.[58]

Bloom Energy Server's solid oxide fuel cells platform can run on natural gas, biogas, and hydrogen fuel using air and come in a 300 kW module size that can be scaled. A 1 MW plant has been installed at Ferrari's manufacturing facility in Italy offering fuel supply type flexibility required to power the plant[59].

Larger MW scale fuel cell stationery power generation solutions are being considered for data centres as backup or continuous power in Asia. In Australia, stationary fuel cell plants that use hydrogen as fuel are generally small pilot-scale projects and/or installed in commercial buildings and data centres for both power and CHP applications, for example:

- Griffith University in Brisbane has a building which has been run with a 60kW hydrogen fuel cell since 2013[60]

Toyota's Hydrogen Centre of Excellence hydrogen production and refuelling station at Altona, including stationary 30 kW fuel cell for power generation completed in 2021.[61]

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[55] The Future of Hydrogen, Report prepared by the IEA for the G20, Japan, Seizing today's opportunities
[56] https://www.powermag.com/large-scale-hydrogen-projects-take-shape-as-technology-continues-to-evolve/
[57] https://www.nrel.gov/news/program/2022/new-research-collaboration-to-advance-megawatt-scale-hydrogen-fuel-cell-systems.html
[58] https://www.nobletoyota.com.au/news/toyota-set-to-assemble-distribute-stationary-hydrogen-fuel-cell-power-generator
[59] https://www.ferrari.com/en-EN/corporate/articles/a-1-mw-fuel-cell-plant-at-ferraris-maranello-facilities
[60] https://new.gbca.org.au/showcase/projects/sir-samuel-griffith-centre/
[61] https://energys.com.au/green-hydrogen-news/toyota-launches-victorian-hydrogen-production-and-re-fuelling-facility-powered-by-energys-australia

MW scale fuel cell power generation applications are being studied in Australia using renewable hydrogen production and storage for power generation and export during peak times and potential grid stability services.

The drivers for the development of hydrogen fuels cells used for stationary power generation applications will require an available hydrogen supply that is affordable together with fuel cell prices becoming more cost competitive over time as increased capacity is implemented globally.

### 5.5.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2023, given the above discussion on typical options and current trends.

**Table 5-4 Fuel cell configuration and performance**

| Item | Unit | Small | Large | Comment |
|---|---|---|---|---|
| **Configuration** | | | | |
| Technology | | PEM-FC | PEM-FC | Technology offer for the demonstration plant in SA. |
| Make model | | Cummins - Hydrogenics HyPM-XR120 | Cummins - Hydrogenics HyPM-XR120 | Example. |
| Unit size (nominal) | MW | 0.120 | 0.120 | |
| Number of units | | 1 | 12 | (4 x XR30 modules), 1-12 units. |
| **Performance** | | | | |
| Total plant size (Gross) | MW | 0.120 | 1.2 | 25°C, 110 metres, 60%RH |
| Auxiliary power consumption | % | 10% | 10% | Assumption |
| Total plant size (Net) | MW | 0.108 | 1.08 | 25°C, 110 metres, 60%RH |
| Seasonal Rating – Summer (Net) | MW | 0.108 | 1.08 | 35°C, 110 metres, 60%RH |
| Seasonal Rating – Not Summer (Net) | MW | 0.108 | 1.08 | 15°C, 110 metres, 60%RH |
| Heat rate at maximum operation | (GJ/MWh) HHV Net | 11.36 | 11.36 | Based on a fuel consumption of 0.08 kg/kWh (net). OEM provided data. |
| Heat rate at minimum operation | (GJ/MWh) HHV Net | 7.1 | 7.1 | Based on a fuel consumption of 0.05 kg/kWh (net). Typical |
| Thermal Efficiency at MCR (minimum to maximum operation) | %, HHV Net | 50.7-31.6% | 50.7-31.6% | 25°C, 110 metres, 60%RH |
| Hydrogen consumption at MCR | kg/h | 8.64 | 86.4 | |
| **Annual Performance** | | | | |
| Average Planned Maintenance | Days / yr. | - | - | Included in EFOR below. |
| Equivalent forced outage rate | % | 2% | 2% | |

Table 5-5 Technical parameters and project timeline

| Item | Unit | Small | Large | Comment |
|---|---|---|---|---|
| **Technical parameters** | | | | |
| Ramp Up Rate | MW/min | 0.926 | 9.25 | Based on 0% to 100% in 7 secs as per OEM datasheet. |
| Ramp Down Rate | MW/min | 0.926 | 9.25 | Based on 100% to 0% in 7 secs as per OEM datasheet. |
| Start-up time | Min | Cold: 5<br>Warm: 0.5 | Cold: 5<br>Warm: 0.5 | Typical |
| Min Stable Generation | % of installed capacity | 10% | 10% | Typical Continuous Minimum turndown |
| **Project timeline** | | | | |
| Time for development | Years | < 1 | <1 | includes pre/feasibility, design, approvals etc. |
| First Year Assumed Commercially Viable for construction | Year | 2024 | 2024 | |
| EPC programme | Years | < 1 | <1 | For NTP to COD. |
| ▪ Total Lead Time | Years | 0.75 | 0.75 | Time from NTP to Fuel cell delivery to site. |
| ▪ Construction time | Weeks | 13 | 20 | Time from fuel cell on site to COD. |
| Economic Life (Design Life) | Years | 8 | 8 | Based on a capacity factor of 38% with a typical stack replacement frequency of 25,000 operating hours (replacement frequency depending on operating conditions and routine maintenance carried out) |
| Technical Life (Operational Life) | Years | 20 | 20 | |

### 5.5.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 5-6 Cost estimates

| Item | Unit | Small | Large | Comment |
|---|---|---|---|---|
| **CAPEX – EPC cost** | | | | |
| Relative cost | $ / kW | 14,300 | 6,600 | Aurecon in-house database. Includes full turn-key EPC for standalone installation including cooling systems and connection to electrical system LV. Relative cost does not include land and development costs. |

| Item | Unit | Small | Large | Comment |
|---|---|---|---|---|
| Total EPC cost | $ | 1,716,000 | 7,920,000 | |
| ▪ Equipment cost | $ | 1,372,800 | 6,336,000 | 80% of EPC cost – typical. |
| ▪ Construction cost | $ | 343,200 | 1,584,000 | 20% of EPC cost – typical. |
| **Other costs** | | | | |
| Cost of land and development | | 344,000 | 792,000 | Assuming 10-20% of CAPEX due to overall small footprint. |
| Fuel connection costs | $ | Excluded | Excluded | Pressure let-down equipment may be required depending on hydrogen supply pressure. |
| **OPEX – Annual** | | | | |
| Fixed O&M Cost | $ / MW (Net) | 572,000 | 264,000 | Based on 5% of equipment CAPEX per year.[62] |
| Variable O&M Cost | $ / MWh (Net) | - | - | Included in the fixed O&M component. |
| Total annual O&M Cost | $ | 68,640 | 316,800 | Annual average cost over the design life. Dependent of annual capacity factor. Excludes stack replacement. Includes scheduled maintenance and operator allowance. |

## 5.6 SMR and CCS

### 5.6.1 Overview

Steam Methane Reforming (SMR) is a method for producing grey or blue hydrogen by passing methane and steam over a catalyst at high temperature at moderate pressure.

The process follows the two following reactions:

Reforming:

$$CH_4 + H_2O \rightleftharpoons CO + 3\ H_2$$

CO formed in the reforming reaction is then converted by water-gas shift (WGS):

$$CO + H_2O \rightleftharpoons CO_2 + H_2$$

Following reforming and purification, the produced hydrogen can be stored, transported or consumed by a variety of methods. This includes compression and liquefaction for transport by cylinder, pipeline transport and conversion to ammonia for use as chemical feed stock or export. SMR plants are typically installed for production of hydrogen as a chemical feed stock and often produce steam for other plant demands as a by-product. SMR plants currently produce 95% of the world's hydrogen.[63] The International Energy Agency reports low emissions hydrogen production in 2022 less than 1% of total hydrogen production[64].

[62] Eichman J, Townsend A, Melaina M (2016), "Economic Assessment of Hydrogen Technologies Participating in California Electricity Markets", National Renewable Energy Laboratory, NREL/TP-5400-65856
[63] Rapier 2020, Estimating The Carbon Footprint Of Hydrogen Production, https://www.forbes.com/sites/rrapier/2020/06/06/estimating-the-carbon-footprint-of-hydrogen-production
[64] https://www.iea.org/energy-system/low-emission-fuels/hydrogen

Blue hydrogen production is achieved here by implementing Carbon Capture Utilisation and Storage (CCUS) to the waste streams from the plant. Without CCS, it is referred to as grey hydrogen.

The SMR process produce hydrogen and carbon dioxide, typically in ratios of approximately 1kg $H_2$ to 7-10 kg $CO_2$ (including combustion products from the plant process burners). With CCS implemented, this can be reduced to 1 kg $CO_2$ per kg $H_2$.

Carbon Capture is generally performed by passing the hydrogen/carbon dioxide gas stream through an absorption column with one of many commercially available absorbent solution products (usually amine based), and then removing the carbon dioxide from the absorbent in an adjacent stripper column. The carbon dioxide is then usually compressed and transported by pipeline to a well field for injection underground or stored for usage as a product. Carbon capture installations will reduce the efficiency of the SMR, with additional energy requirements for pumping and heat for stripping. Approximately 1% of fossil-fuel sourced hydrogen production currently includes CCS[65].

### 5.6.2 Current trends

Plants currently operating in Australia produce Hydrogen by reforming natural gas or gasification of coal without CCS, and have capacities between 40 and 400 t $H_2$/day (between 18.5 and 141 ktpa).[66]

Reformer technologies have been mature and stable for some years now and are unlikely to improve significantly (Reactor design technologies offered over the last twenty years claim an improvement of approximately 20% over traditional reformers,[67] though this efficiency should already be incorporated into any new plant). Opportunities may exist for retrofitting CCS equipment to SMR plants with the location of storage operations of primary consideration in determining costs. Recent studies have claimed that $CO_2$ emissions from SMR with CCS are approximately 2-3 kg $CO_2$/kg $H_2$ (Zapantis, 2020).

Studies have shown that carbon dioxide transport and storage infrastructure would cost in the order of $5 - $15 /t $CO_2$ for short transport distances to a high value of $75/t $CO_2$ for long transport distances.[68]

Depending on the intended hydrogen consumers, current SMR plant designs are capable of generating more than enough gas to meet demand. For example, the CCS institute report estimates that, in order to blend hydrogen into the New South Wales natural supply at a concentration of 10%, approximately 30,490 Tonnes per annum is required.

This production rate is achievable by the smallest of currently operating SMR plants in Australia. Other consumers are expected to have significantly greater demands (including those current consumers) and would benefit from larger SMR facilities.

### 5.6.3 Selected hypothetical facility and cost estimate

For this study, production of hydrogen by SMR is assumed to be produced at large scale, with the intent of serving local consumers as well as an export facility.

**Table 5-7 SMR plant criteria**

| Item | Low | High | Comment |
|---|---|---|---|
| Hydrogen production rate | 200,000 kg/day | 900,000 kg/day | Based upon North American plants. Given expected future demand, plant size expected to increase above current Australian sizes to typical large international plants. |
| $CO_2$ production rate | 7 kg $CO_2$/kg $H_2$ | 9 kg $CO_2$ /kg $H_2$ | Prior to CCS |
| $CO_2$ emission rate after CCS | | 2 kg $CO_2$ / kg $H_2$ | Assumed |
| Water required | 6.3 kg/kg $H_2$ | 6.3 kg/kg $H_2$ | reported in Zapantis 2020 |

[65] https://www.globalccsinstitute.com/wp-content/uploads/2021/04/CCE-Blue-Hydrogen.pdf
[66] De Vos 2021, Australian hydrogen market study, https://www.cefc.com.au/media/nhnhwlxu/australian-hydrogen-market-study.pdf
[67] https://www.topsoe.com/products/equipment/convection-reformer-htcr?hsLang=en
[68] Electric Power Research Institute, 2015 Australian Power Generation Technology report

| Item | Low | High | Comment |
|---|---|---|---|
| Land Area | 3 Ha for plant, 500 Ha for 500 km $CO_2$ pipeline easement. | | Reported in Zapantis 2020 for 80 T/d plant, includes CCS and excludes gas supply pipeline and infrastructure. |

A mid-range cost has been assigned for $CO_2$ transport and storage. It is assumed here that a SMR plant would be of larger capacity and at a location near hydrogen users, rather than near $CO_2$ storage sites. The larger capacity plant would have a higher $CO_2$ generation rate, enabling improved per-tonne pipeline transport costs, though the location would require a longer pipeline to the storage facility. Thus, $CO_2$ transport and storage costs are assumed to be $32ft/t $CO_2$.[69]

**Table 5-8 SMR plant cost estimate**

| Item | Low | High | Comment |
|---|---|---|---|
| Hydrogen production rate | 200 tonne/d | 900 tonne/d | |
| Cost of production | AUD $2.31/kg $H_2$ | AUD $3.46/kg H2 | Reported in Zapantis 2020.[70] Note- the low and high-cost figures refer to range of costs not plant size, larger plants are normally more efficient |
| CAPEX | AUD $1,459/kW $H_2$ | | (with no carbon capture) |
| CAPEX | AUD $2,026/kW $H_2$ | AUD $2,667/kW $H_2$ | (with carbon capture)[71] |
| Total Capex Cost | AUD $672 M | AUD $3,003 M | Total CAPEX with CCS |
| OPEX / year | AUD $19.95 M | AUD $90.3 M | |

Based on the CAPEX data listed in Table 5-8, an SMR plant of 900 tonne $H_2$/day capacity would cost of the order of AUD $2.1B without carbon capture and $2.9B with. These estimates are for the plant only and do not include transport and storage costs for $H_2$ or $CO_2$.

## 5.7 Hydrogen storage

### 5.7.1 Overview and selected options

The inclusion of hydrogen storage at a hydrogen production site is dependent on the use case (offtake arrangement) for that hydrogen. The requirement for storage is particularly prevalent when hydrogen production is connected to a downstream processing facility which requires a steady feed flow (eg an ammonia or liquefaction plant).

Bulk hydrogen storage has several difficulties to overcome. Hydrogen is a light gas with low density, with 1kg occupying approximately 11m$^3$ at ambient conditions. Storing this volume would be impractical, so a storage facility must reduce the volume of hydrogen by some means. The main industrial storage options are the following:

- Pressurised Tanks: Hydrogen is compressed to high pressure as a gas. Whilst pressures of up to 700 bar are possible, most compressed storage is less than 200 bar, owing to operating and safety concerns.[72] These may range from a small 49L gas cylinder containing 0.65 kg Hydrogen at 164 Bar to large industrial vessels.[73] Hydrogen pressure vessels are classified by material, with four main types. Type I is all metal construction, typical max pressure of 200 Bar. Type II is mostly metal, with composite overwrap in the hoop direction and typical maximum pressures of 200 Bar. Type III is metal lined with a full composite wrap,

[69] Electric Power Research Institute, 2015 Australian Power Generation Technology report fig 138
[70] Zapantis 2020- Replacing 10% of NSW Natural Gas Supply with Clean Hydrogen: Comparison of Hydrogen Production Options
[71] IEA (2019), The Future of Hydrogen, Assumptions annex, IEA, Paris https://www.iea.org/reports/the-future-of-hydrogen
[72] Anderson and Gronkvist, 2019. Large-scale storage of hydrogen, International Journal of Hydrogen Energy, (44) pp. 11901-11919
[73] Lee's Loss Prevention in the Process Industries, Chapter 22.14

typical maximum pressures of 700 Bar. Type IV are all composite construction, typical maximum pressures of 700 Bar. Many new projects are considering type IV pressure vessels to store hydrogen[74]

- Cryogenic Liquid Hydrogen Storage: hydrogen is cooled to approximately -252°C. This is then stored as a liquid in insulated tanks, known colloquially as Dewar flasks. This requires a liquefaction plant for cooling to low temperatures, and specially designed insulated tanks, typically with vacuum-sealed double-shell thermal insulation. These tanks are operated at atmospheric pressure, and a small amount of hydrogen is lost in evaporation. Liquid hydrogen is not very dense, with a density of approximately 70 kg/m$^3$
- Geologic hydrogen storage: Hydrogen is injected under pressure into an underground gas reservoir such as depleted natural gas well and salt cavern. This is considered in more detail below under Section 5.8.

Whilst there are other possible mechanisms such as adsorption onto surfaces and formation of metal hydrides, these methods have yet to be developed industrially at scales considered for this report and are not considered further. Note that hydrogen is an explosive gas and all large storage sites will be considered a Major Hazard Facility (MHF) and will be governed by MHF legislation.

### 5.7.2 Recent trends

The current trend in compressed gas storage tanks is towards higher pressure storage. This is partly driven by the requirements of hydrogen vehicles, which have limited space for an onboard tank. The higher the pressure, the greater the density of hydrogen and thus the mass of hydrogen stored. This is weighed against the greater risk of rupture and explosion at higher pressure, as well as the specialised materials and wall thickness required to store a gas at high pressure with associated higher costs.

The hydrogen automotive vehicle industry has seen the development of high pressure tanks. Commercial fuel cell electric vehicles such as the Toyota Mirai and the Honda Clarity both rely on compressed hydrogen for pressure vessels for onboard hydrogen storage.

The maximum pressure is 700 bar, although industry is aiming to go higher. The pressure is extremely high and demands an extremely robust tank. At these pressures, Type III or IV pressure vessels are used.[75]

There has recently been an increase in the size and number of cryogenic liquid hydrogen storage facilities. Part of this is driven by the desire to make bulk liquid hydrogen into a commodity which may be shipped, requiring large storage facilities at supply and delivery terminals. The largest liquefaction plant is currently 32 tpd liquid Hydrogen.[76] Plans are under way to build a plant with 90 tpd capacity.[77]

Japan has seen heavy development in Hydrogen storage, partly as a means of lowering greenhouse gas emissions. The world's first liquefied hydrogen carrier, the 116 m Suiso Frontier was recently launched by Kawasaki Heavy Industries.[78] The same company has also announced the design of 10,000m$^3$ storage facility for liquid hydrogen, but this has yet to be built.[79]

Nasa currently operates the largest hydrogen storage tank at Cape Canaveral at the US, for fuelling of spacecraft, with a maximum capacity of 270 t or roughly 3800m$^3$.[80]

[74] Rivard et al 2019- Hydrogen Storage for Mobility: A Review Materials, 12, 1973; doi:10.3390/ma12121973
[75] Rivard et al 2019- Hydrogen Storage for Mobility: A Review Materials, 12, 1973; doi:10.3390/ma12121973
[76] Decker 2019- Latest Global Trend in Liquid Hydrogen Production
[77] Hydrogen Liquefiers | Air Liquide (engineering-airliquide.com)
[78] Be water: Japan's big, lonely bet on hydrogen - Nikkei Asia
[79] Kawasaki Completes Basic Design for World's Largest Class (11,200-cubic-meter) Spherical Liquefied Hydrogen Storage Tank | Kawasaki Heavy Industries, Ltd.
[80] Anderson and Gronkvist, 2019. Large-scale storage of hydrogen, International Journal of Hydrogen Energy, (44) pp. 11901-11919


**Figure 5-1 Hydrogen storage tank, Cape Canaveral (picture NASA)**

Whilst traditional cryogenic tanks with venting are dominant, NASA recently announced an attempt to avoid the evaporation losses of traditional liquid hydrogen storage. The proposed method involves cooling tanks via an external heat exchanger.[81]

### 5.7.3 Selected hypothetical project and cost estimate

For the purpose of hydrogen storage from a SMR plant, a cryogenic storage liquid hydrogen storage facility has been selected as a hypothetical project. This would be a facility for bulk storage of hydrogen, such as a marine import or export facility. The hypothetical facility has been sized according to the requirements of 10 days storage for a plant production of 27 t/day. This nominal size of 27 t/day was chosen as performance and cost data are available from a US study[82].

**Table 5-9 Liquid hydrogen storage hypothetical technical parameters**

| Item | Value | Units | Comment |
|---|---|---|---|
| Hydrogen production rate | 27000 | kg $H_2$/ day | Based on a proposed plant for Los Angeles, by Connelly et al.[82] |
| Electricity Usage | 12 | kWh / kg $H_2$ | Medium value from Connelly et al[82], Connelly recommends 10-20 |
| Energy Usage per day | 324,000 | kWh /day | |
| Storage requirement | 10 | Days | Assumed |
| Mass Liquid $H_2$ Stored | 270 | T Liquid $H_2$ | Note this is similar in size to the largest vessel, multiple small tanks would be better than a single large vessel |

**Table 5-10 Liquid hydrogen storage hypothetical project cost parameters**

| Item | Value | Units | Comment |
|---|---|---|---|
| Cost of Liquefaction and storage Plant Capex | 203 | $M AUD | From Connelly et al[82] |
| OPEX costs | 2.14 | $ AUD /kg $H_2$ | OPEX costs with CAPEX Component removed from US Study |
| OPEX / Year | 23.3 | $M AUD /yr | |

[81] Innovative Liquid Hydrogen Storage to Support Space Launch System | NASA
[82] Connelly et al 2019 - Current Status of Hydrogen Liquefaction Costs

| Item | Value | Units | Comment |
|---|---|---|---|
| Mass Liquid $H_2$ Stored | 270 | T Liquid $H_2$ | Note this is similar in size to the largest vessel, multiple small tanks would be better than a single large vessel |

For the purpose of storage of hydrogen from an electrolyser plant, pressurised tanks are assumed as the storage type with assumptions as provided in Section 3.2.5.

### 5.7.4 Hydrogen pipelines and associated costs

Transmission and distribution of hydrogen to end users requires a pipeline network. Hydrogen is normally transferred to users in standard piping materials, such as mild steel, stainless steels or HDPE. There are certain issues relevant to hydrogen piping. Durability of some metal pipes may degrade over time when exposed to hydrogen, particularly with high purity hydrogen at high pressures, a phenomenon known as hydrogen embrittlement. This effect is highly dependent on metals used but presents an issue adding hydrogen to existing gas networks. For many common piping materials such as HDPE or PVC there are no concerns about hydrogen damage.[83]

Leakage is also an issue with hydrogen as hydrogen is more mobile than natural gas, particularly in plastic piping. Permeation rates of hydrogen are approximately 4-5 times that of methane in typical HDPE pipes, leading to increased hydrogen losses compared to natural gas. Leakage losses can be minimised with a new network designed for hydrogen.[37]

There has been some blending of hydrogen into existing natural gas networks. Hydrogen is less energy dense than natural gas on a volume basis than natural gas. This can lead to issues for end users with burners not designed for a mixture of natural gas and hydrogen. Hydrogen typically cannot be raised above 10% in existing gas networks before problems occur.

In some cases, an existing natural gas network may be re-purposed as a hydrogen transmission network. APA is planning to convert 43 km of the existing Parmelia Gas Pipeline in Western Australia to hydrogen with pipe steel compatibility confirmed during a feasibility study in 2023.[84]

Leakage and embrittlement are however widely understood, and hydrogen pipelines are becoming more common. There are currently approximately 1600 miles of hydrogen pipelines in the United States at time of writing.[85] Whilst some existing gas networks may be repurposed for hydrogen, the likelihood is that new hydrogen distribution networks will be required for Australia’s hydrogen targets to be met.

Pipeline costs vary tremendously, depending upon pipeline materials, size capacity, pipeline materials and the terrain being traversed. Costs in flat level, terrain are much cheaper than buried lines in mountain. GIS tools have seen widespread use in hydrogen piping design. To estimate costs in an Australian context, Aurecon has assumed that costs are based on a new low-pressure hydrogen distribution network, separate to existing natural gas networks for the purpose of domestic hydrogen use from SMR plant. Indicative costs are based on the assumption that the network must distribute hydrogen equivalent to 10% of the annual NSW natural gas consumption. This is not assumed to contain all the small bore lines to end users, only the main distribution headers assumed to be DN150.

Two distribution options are presented below, one with a buried HDPE network operating at low pressure (3 Bar) and a buried steel pipe network operating at medium pressure (7 Bar). One factor to consider in network design is that the low density of hydrogen leads to a lower mass flow. This can be partially mitigated by operating at higher pressure, but this is unlikely to be acceptable within an urban area.

Indicative costs for a new hydrogen distribution network using hydrogen produced from a SMR plant are shown below and assume direct injection of hydrogen without storage.

Transport of hydrogen produced from a hypothetical 10 MW electrolyser plant is assumed to be via a pipeline with assumptions as stated in Section Hydrogen-based technologies and storage.

[83] Melaina et al 2013, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues https://www.nrel.gov/docs/fy13osti/51995.pdf
[84] APA ASX release May 2023 https://www.apa.com.au/news/asx-releases/2023/the-parmelia-gas-pipeline/
[85] US Department of Energy Hydrogen Pipelines | Department of Energy

**Table 5-11 Indicative costs for a new hydrogen distribution network**

| Item | Value (HDPE) | Value (Steel) | Units | Comment |
|---|---|---|---|---|
| Design Throughput | 83.5 | 83.5 | tonne $H_2$/ day | 10% of NSW Natural Gas Consumption[86] |
| Design Throughput | 1.0 | 1.0 | kg/s | 10% of NSW Natural Gas Consumption |
| Gas Pressure | 3 | 7 | Bar | Assumed |
| Pipeline Velocity | 15 | 15 | m/s | Assumed-[87] refer IEA G20 Hydrogen report: Assumptions |
| Hydrogen Density | 0.25 | 0.59 | kg/m$^3$ | At 3 and 7 Bar, and 15C—calculated |
| Main Header Size | 160 | 150 | mm | Assumed SDR 11 HDPE for Gas service for HDPE. Sch 40 for steel |
| Maximum Gas Flow / header | 0.05 | 0.15 | kg/s | Calculated |
| Number of parallel pipelines required | 20 | 7 | | Calculated based upon maximum gas flow per pipe |
| Length of pipelines | 60 | 60 | km | Assumed |
| Pipeline Cost | 445 | | $AUD /m | Based upon a South Australian project |
| Transport pipeline cost | | 84,000 | $AUD /km/inch | Based upon Aurecon inhouse data |
| Network Cost | 533 | 210 | $M AUD | |

## 5.8 Geological hydrogen storage

### 5.8.1 Overview

Commercial scale hydrogen production, like any chemical, requires a storage solution to ensure balance between facility inflow (supply) and outflow (demand). Geologic hydrogen storage (GHS) offers an alternative to pressure vessels for gaseous hydrogen storage. GHS refers to storage of hydrogen molecules in underground stores, primarily:

- Porous rocks (aquifers, depleted gas/oil reservoirs)
- Artificially created underground spaces (salt caverns, lined rock caverns, disused mines).

The only geologic storage technology to be used at commercial scale is salt caverns (TRL 8). All other GHS technologies are currently under development (TRL 5-6), with pilot projects predominately in Europe and the USA (Argonne National Laboratories, 2019). To date, limited research has been conducted in assessing the potential for Australian GHS.

**Table 5-12 Geological storage technology comparison**

| Parameter | Salt cavern | Depleted reservoir | Aquifer |
|---|---|---|---|
| Technology Readiness Level (TRL) | 8 | 6 | 5 |
| Capital Cost | Middle | Lowest | Highest |

[86] Zapantis 2020- Replacing 10% of NSW Natural Gas Supply with Clean Hydrogen: Comparison of Hydrogen Production Options
[87] IEA G20 Hydrogen report: Assumptions Annex

| Parameter | Salt cavern | Depleted reservoir | Aquifer |
|---|---|---|---|
| Operating Cost | Highest<br>(Up to 10 gas cycles per year) | Lowest<br>(Up to 2 cycles per year) | Lowest<br>(Up to 2 cycles per year) |
| Technical Considerations | ▪ Large volume of water required for cavern leaching<br>▪ Brine disposal following cavern leaching | ▪ Impurities resulting in production of methane, $H_2S$<br>▪ Reactivity of hydrogen with liquid remaining liquid hydrocarbons | ▪ Risk of gas leakage (aquifer tightness)<br>▪ Impurities resulting in production of methane, $H_2S$ |

Geologic storage systems typically operate between 70-200 bar. As pressure increases, the total amount of gas storage increases at the expense of installing additional above ground equipment. All geologic storage systems have an above ground and below ground component. An example schematic for a salt cavern option is provided in Figure 5-2.

- Above ground equipment includes gas treatment (dehydration and chemical injection), compression (including cooling) and pressure let-down. These systems are common to all GHS projects and account for 10-30% of total project capital depending on storage pressure
- Below ground equipment consists of the reservoir (including costs to purge), tunnels and associated drilling and completions infrastructure. For lined caverns a below ground cost will also include installation of the reservoir liner. Below ground costs account for 60-90% of total project capital.

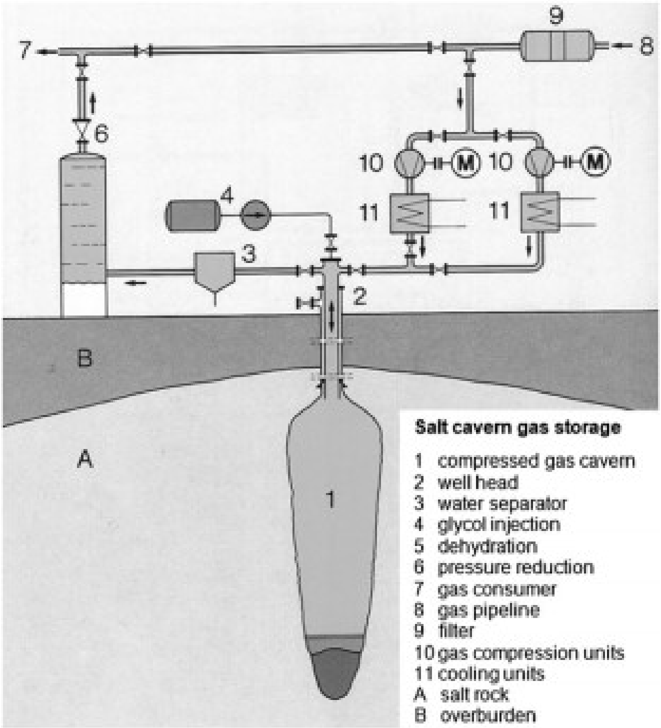


Figure 5-2 Salt cavern storage schematic (Ozarslan, 2012)

## 5.8.2 Recent trends

There are currently only four locations in the world which operate GHS at >95% purity of hydrogen. Table 5-13 provides a summary of major operating sites.

Table 5-13 Geologic hydrogen storage operating sites (Zavir, Kumar, Foroozesh, 2021)

| Project Name | Operator | Hydrogen Purity | GHS Type | Working Pressure (bar) | Mean Depth (m) | Cavern Volume ($m^3$) | Max. Storage Mass (tonne) |
|---|---|---|---|---|---|---|---|
| Teesside (UK) | Sabic Petroleum | >95% | Bedded salt | 45 | 365 | 210,000 | ~750 |
| Clemens (USA) | ConocoPhillips | >95% | Salt dome | 70-137 | 1,000 | 580,000 | ~5,500 |
| Moss Bluff (USA) | Praxair | >95% | Salt dome | 55-152 | 1,200 | 566,000 | ~6,000 |
| Spindletop (USA) | Air Liquide | >95% | Salt dome | 68-202 | 1,340 | 906,000 | ~12,500 |

With increasing focus on commercial scale hydrogen project, several pilot studies across the northern hemisphere have been commissioned. These will assess the viability of storing hydrogen in depleted gas reservoirs.

In July 2021, the Future Fuels Cooperative Research Centre (CRC) released a report mapping underground hydrogen storage potential in Australia. The CRC estimates that ~310 million tonnes of hydrogen storage in depleted gas reservoirs is possible. Despite this, the technology readiness level of converting depleted reservoirs to hydrogen storage facilities is low, with current viable storage location limited to areas with large salt deposits. These projects will be confined to Western Australia, South Australia and the Northern Territory (as per Figure 5-3).

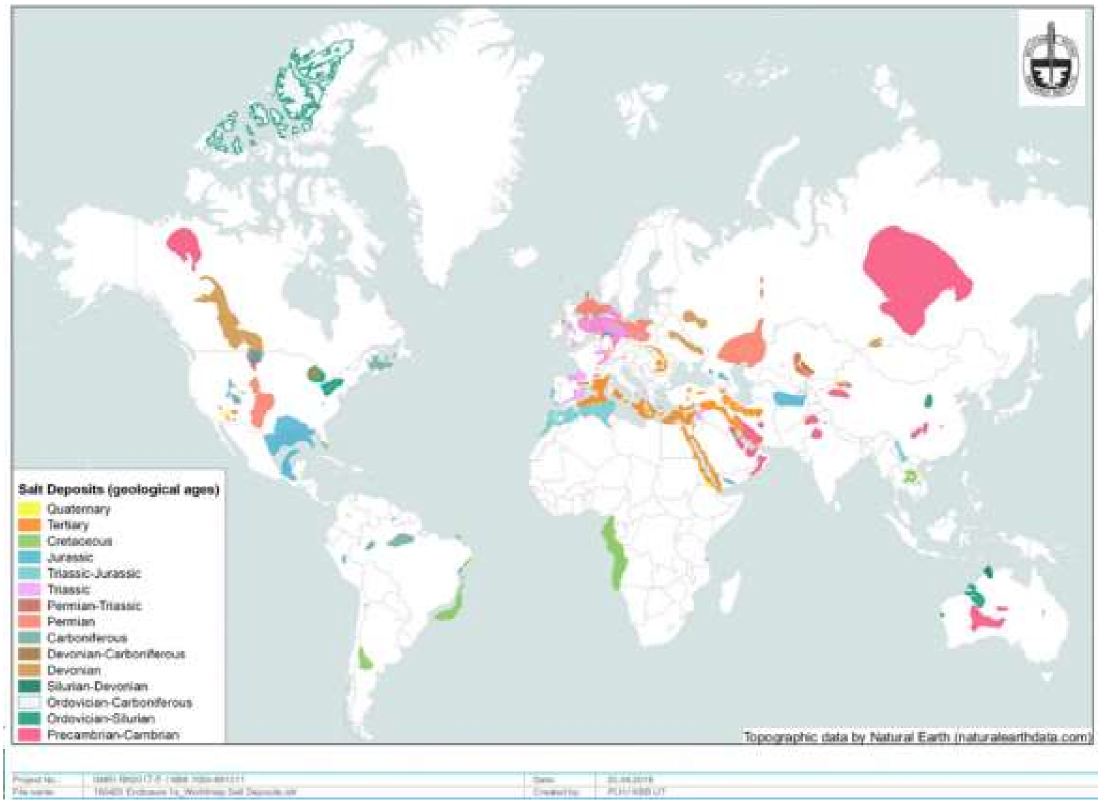


Figure 5-3 Global salt deposit locations (Engie, 2019).

### 5.8.3 Selected hypothetical project and cost estimate

The selected hypothetical project is a salt cavern that reflects operating conditions of existing projects in the UK and USA. The potential for salt cavern storage at this scale in an Australian context has yet to be explored.

**Table 5-14 Hypothetical geologic storage project parameters**

| Item | Unit | Value | Comments |
|---|---|---|---|
| **Configuration** | | | |
| Cavern Volume | $m^3$ | 300,000 | Average sized cavern, unknown if viable in Australian context |
| Maximum Storage Capacity | tonne | ~2,200 | Stored hydrogen mass at operating temperature and pressure |
| Mean Depth | m | 1000 | Salt deposits can range from 200-1500m in depth. |
| Working Capacity | $m^3$ | 210,000 | 30% cushion gas, required to maintain pressure for withdrawal and injection |
| **Performance** | | | |
| Hydrogen Purity | % | > 95% | Commercial grade hydrogen |
| Gas Cycling Requirements | - | 10 annual cycles | Impacts operating costs |
| Operating Pressure | bar | 100 | |
| Operating Temperature | °C | 30-40 | |
| Energy Consumption | MWh/tonne | 1.2 | Energy for hydrogen compression (assumed from 10 Bar to 100 Bar) |
| **Project Timeline** | | | |
| Project Development | months | 12-18 | From concept to FID (engineering only, not approvals which may take longer) |
| Project Execution | years | 5-7 | From FID to commissioning |
| Major Turnaround Cycle | years | 3-4 | Driven by compressor maintenance requirements |

The following table provides the cost parameters (excluding owner's costs) for the hypothetical project as outlined above, noting that costs are reflective of the project in the table above.

**Table 5-15 Hypothetical project CAPEX and OPEX costs**

| Item | Unit | Value | Comments |
|---|---|---|---|
| **CAPEX** | | | |
| Engineering | $M AUD | 7-10 | Includes engineering and geotechnical activities |
| Below Ground Costs | $M AUD | 35-58 | Cavern and tunnel excavation, leaching |
| Leaching and Brine Disposal | $M AUD | 5-11 | Assumes $2.10 per barrel for brine disposal |
| Above Ground Costs | $M AUD | 15-37 | Includes compression, treatment and let-down kit, as well as piping |
| **OPEX** | | | |
| Operations and Maintenance | $M AUD per year | 1.1 -2.1 | Assumes OPEX is 2.2% of capital costs of above and below ground CAPEX. |

# 6 Ammonia Production Facility

## 6.1 Overview

Ammonia production commenced at an industrial scale in the early twentieth century with the development of the Haber-Bosch process, which reacts hydrogen with nitrogen over a metallic catalyst, typically under high pressure and temperature. The synthesis process follows the equation below and the reaction is exothermic.

$$N_2 + 3H_2 \rightleftharpoons 2NH_3 + 42 \text{ kJ/mol}$$

Traditionally the hydrogen is sourced from a hydrocarbon source such as natural gas or coal and the nitrogen from the atmosphere. While there are a variety of process available the dominant is Steam Methane Reforming (SMR), where natural gas is the feedstock.

The vast majority of ammonia produced today is used as fertiliser (around 70%), however it is also used in explosives, and as a refrigerant. The global production of ammonia is in the order of 180 million tonnes per year, of which approximately 1% occurs in Australia. Australia has 2 ammonia production plants in Western Australia, 4 in Queensland and 1 in New south Wales, all using natural gas as a feedstock. Ammonia production accounts for approximately 1 - 2% of global $CO_2$ emissions.

Ammonia is being re-visioned as a potential 'zero carbon fuel', this being true as no carbon is emitted during consumption, however in the conventional process of SMR $CO_2$ is released in the manufacturing process. Where this $CO_2$ is captured and stored/used the ammonia is known as 'blue'. Where the process no longer uses hydrocarbons as a hydrogen source, and instead uses renewable energy and water, the resulting ammonia can be referred to as being 'green'.

Green ammonia offers a potential solution for decarbonising difficult-to-abate sectors such as fertiliser production & maritime transport (via direct combustion).

Traditional ammonia plants range from approximately 250 tonnes per day up to over 3,000 tonnes per day. Ammonia licensors are now producing designs for plants that exceed 5,000 tonnes per day in response to growing global demand.

## 6.2 Recent trends

Over the past years and decades, the trend in conventional ammonia plants has been towards large plants as they are able to achieve higher efficiencies and generally have a lower specific capex (cost per annualised unit output). Given the significant carbon dioxide emissions associated with ammonia production, both producers and technology providers are looking at ways to reduce the carbon footprint. Some producers are exploring the potential of blending 'green' hydrogen from an electrolysis process into their existing plants, as a step toward a full replacement of the hydrocarbon-based hydrogen supply. Several global ammonia technology companies are either developing electrolysis technology internally or are forming partnerships with suppliers to be able to offer an integrated plant.

While the ammonia synthesis process in a plant using electrolysis as a hydrogen supply will still rely on the Haber-Bosch process, the process will need to change to cater for the pure hydrogen feed and the possibility of a fluctuating feed rate, resulting from the variable renewable energy source. Options to mitigate the impact of a fluctuating renewable energy supply include the use of energy storage (such as large-scale batteries), or hydrogen storage. Generally, the optimal solution is identified during the design phase, and this optimisation provides the lowest levelised cost of ammonia (LCOA).

While traditionally synthesis plants were operated in a steady state regime, having a plant which is able to turn down to match generation is now advantageous. Modern ammonia plant designs allow for turndown ratios as low as 10%.

While the larger plants will continue to be more efficient and cost effective, as the access to green hydrogen is much more geographically distributed than natural gas, building a plant closer to the end user is becoming more feasible. This can result in reduced transport and storage costs which can negate and compensate for the efficiency penalties of having a smaller plant. As such the technology providers are again offering smaller plants to suit this emerging market.

## 6.3 Selected hypothetical project

For the purposes of this document, it has been assumed that the ammonia plant would be used as a means to export renewable energy, in a chemical form, to customers not connected to the NEM. The plant is understood to include the required balance of plant equipment necessary to produce ammonia and export it in liquid form. It does not include the hydrogen supply equipment, (including storage) or the downstream storage and export infrastructure.

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is viewed as a typical project for development as an export solution in 2024 given the above discussion on typical options and current trends.

Due to its size this plant will be classified as a Major Hazard Facility (MHF). This classification extends the project approvals pathway and overall development timeline.

**Table 6-1 Hypothetical ammonia production facility configuration and performance data**

| Item | Unit | Value | Comments |
|---|---|---|---|
| **Configuration** | | | |
| Ammonia Synthesis | | Haber-Bosch Process | |
| Nitrogen Supply | | Air Separation Unit (ASU) | |
| Cooling | | Cooling tower | |
| Waste Heat Recovery | | Steam Turbine Generator | Process will produce excess heat in the form of steam which can be used to generate electricity |
| **Performance** | | | |
| Daily Ammonia production (rated) | tpd | 1,000 | |
| Energy Consumption | MWh/t($NH_3$) | 0.8-1.5 | Includes power demand of the synthesis loop, the air separation unit (ASU) and power for hydrogen compression |
| Hydrogen consumption | kg($H_2$)/t($NH_3$) | 180 | Based on synthesis consumption with 98% efficiency, not inclusive of fuel demands for heating, etc. |
| Water Consumption | $m^3$/t($NH_3$) | 0.2-1.0 | Cooling water make-up rate. Varies depending on cooling method, heat integration, water quality and climate |
| **Annual Performance** | | | |
| Annual Ammonia output (typical) | tpa | 350,000 | Based on 350 online days per year (approximately 96% availability) |
| Stream Days | No. | 350 | As above |

**Table 6-2 Hypothetical ammonia production facility technical parameters and project timeline**

| Item | Unit | Value | Comments |
|---|---|---|---|
| **Technical Parameters** | | | |
| Minimum Turndown | % of rated capacity | 10-60% | Turndown capability varies across technology providers |
| Synthesis Loop Pressure | bar | 150-200 | Synthesis loop pressure is unique to the technology providers equipment and catalyst. |
| Catalyst | | Iron based | Specifics around catalyst vary from vendor to vendor |

| Item | Unit | Value | Comments |
|---|---|---|---|
| Footprint | | 100m x100m | |
| **Project Timeline** | | | |
| Project Development | months | 18 - 24 | From concept to FID |
| Project Execution | months | 18-30 | From FID to commissioning |
| Economic Life (Design Life) | years | 25 | |
| Operational Life | years | 25 | |
| Major Turnaround Cycle | years | 3-4 | Driven by catalyst change and major rotating equipment overhaul |

## 6.4 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 6-3 Hypothetical ammonia production facility cost estimate**

| Item | Unit | Value | Comments |
|---|---|---|---|
| **CAPEX** | | | |
| Pre FID Engineering | $M | 4 | |
| Execution Cost (TIC) | $M | 600-1000 | Includes air separation unit, installation, project management. Excludes ammonia storage and hydrogen production and storage, owner's costs and duties |
| **OPEX** | | | |
| Operations and Maintenance | $M per year | 9-15 | Assumes 1.5% of CAPEX as operating costs. Excludes power and water consumption |

# 7 Desalination and Water Treatment

## 7.1 Desalination plant

### 7.1.1 Overview

Desalination is the process of removing salinity (dissolved salts) from a saltwater source. It has been commonly used for more than 100 years in dry climates such as the Middle East, Spain, Malta, Cyprus and parts of the United States where access to traditional water supplies is limited.

In Australia there are large-scale desalination plants in Sydney, Perth, the Gold Coast and Adelaide, as well as the Wonthaggi in Victoria which are built to produce sustainable drinking water supply from seawater.

### 7.1.2 SWRO process description

Seawater is drawn in from the ocean through specially designed intake structures. A pre-treatment step is required, which involves either dual-media filtration and chemical dosing for coagulation/flocculation or ultrafiltration, to remove colloidal material and organic matters and reduce water turbidity and silt density index (SDI) in order to prevent damage and fouling of the RO membranes. The pre-treated seawater is passed through cartridge filters before being processed by a seawater reverse osmosis system where relatively high-pressure is applied to water to force it to move from an area of higher salt concentration to an area of lower salt concentration. Seawater is pushed against fine membranes under high pressure and dissolved impurities, such as salt and other minerals, are removed to produce a low total dissolved solids permeate water and a concentrated reject brine stream. The brine is safely returned to the ocean via an outfall through a diffuser structure to avoid any detrimental effects on the aquatic life and the quality of sea water in the discharge area. Permeate is then re-mineralised so it can be blended with other treated water or directly distributed to homes, businesses, and industries in the region to reduce its corrosivity.

The amount of filtered water can be determined from recovery ratio (RR) using equation as follow:

$$Q_p = Q_d * (RR)$$

$$Q_b = Q_d * (1 - RR)$$

Whereby $Q_p$ is volume of permeate produced ($m^3$/day), $Q_b$ is volume of brine produced ($m^3$/day), and $Q_d$ is volume of desalination plant feed water ($m^3$/day). RR is typically between 0.3 to 0.55 for seawater desalination[88].

In order to maintain the efficiency of reverse osmosis unit, the membrane requires chemical cleaning in place (CIP) to remove foulants accumulated on the surface of membranes. Membrane cleaning waste, containing low levels of spent detergent and produced in very small quantities (0.1% or less by volume) compared to concentrate flows, is produced when the membranes are cleaned. Membrane CIP waste and backwash water from the pre-treatment process are typically treated to remove solids or other contaminants and adjust pH prior to being added to the desalination concentrate for discharge.

The typically energy requirement for reverse osmosis process describe is about 9-12 kWh/$m^3$ permeate water. In a multi-pass reverse osmosis process, energy savings can be achieved by reusing the high-pressured brine in the subsequent reverse osmosis step to drive desalination process. As such the energy requirement can be lowered to 2.5-5 kWh/$m^3$ permeate water. However, the energy recovery option has not been included in the CAPEX estimate.

### 7.1.3 Recent trends

Two basic technologies have been widely used to separate salts from ocean water: thermal evaporation and membrane separation.

[88] Metcalf and Eddy 5th Edition Table 11-30

In the past decade, desalination using semi-permeable seawater reverse osmosis (SWRO) membranes has come to dominate desalination markets because of its advantages of high efficiency, simple equipment, and convenient maintenance.

Developments in SWRO desalination technology during the past two decades, combined with a transition to large capacity plants, co-location with power plant generation and enhanced competition from the Build-Own-Operate-Transfer (BOOT) method of project delivery, have resulted in a dramatic decrease of the cost of desalinated water.

One of the key factors that contributed to the decreased cost of seawater desalination is the advancement of the SWRO membrane technology. High-productivity membrane elements are designed with features to yield more fresh water per membrane element: a higher surface area and denser membrane packing. Increasing active membrane surface area allows for significant productivity gains using the same diameter membrane element.

No major technology breakthroughs are expected to dramatically lower cost of seawater desalination in the near future. But the steady reduction of production costs, coupled with increasing costs of water treatment driven by more stringent regulatory requirements, are expected to accelerate the current trend of increased reliance on the ocean as a water source. This will further establish ocean water desalination as a reliable, drought-proof alternative for many coastal communities worldwide.

### 7.1.4 Selected hypothetical project

The selected hypothetical project is a large-scale desalination plant in Australia with production capacity of 40,000 ML/year and located less than 2 km away from feed source with a recovery ratio of 0.4.

### 7.1.5 Cost estimate

The following table provides the cost parameters for the hypothetical full-scale desalination plant project.

**Table 7-1 Cost estimate for full-scale desalination for 100,000 ML/year plant to produce potable water**

| Parameter | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX** | | | |
| CAPEX | $M | 1,700-2,700 | 40,000 $ / (ML/year) based on Australia Water Association – Desalination Fact Sheets – Summary of Australian Desalination plants[89]<br>The cost has been standardised to 2024 value using current Australian inflation rate.<br>Energy recovery option has not been included in the CAPEX. |
| CAPEX breakdown | | | Reference: McGivney and Kawamura (2008) Cost Estimating Manual for Water Treatment Facilities – Reverse Osmosis Treatment Plant |
| ▪ Development cost | % | 20 | |
| ▪ Construction cost | % | 80 | |
| CAPEX Construction Cost Breakdown (% of construction cost) | | | |
| ▪ Intake and brine discharge structure | % | 30 | |
| ▪ Pre-treatment | % | 15 | |

89 http://www.awa.asn.au/AWA_MBRR/Publications/Fact_Sheets/Desalination_Fact_Sheet.aspx

| Parameter | Unit | Value | Comment |
|---|---|---|---|
| ▪ Reverse Osmosis Plant | % | 25 | |
| ▪ Post-treatment (remineralisation) | % | 2 | |
| ▪ Product storage and distribution | % | 10 | |
| ▪ Electrical and instrumentation | % | 8 | |
| ▪ Civil/site and permits | % | 10 | |
| **OPEX - Annual** | | | |
| Power | $M | 22 | In-house Aurecon database, 350-500 $ / ML permeate produced, averaged value is used to determine the cost. Not including energy recovery. Cost could be 20-50% lower if energy recovery is implemented. Energy recovery option has not been included in the OPEX. |
| Chemical | $M | 8.8 | In-house Aurecon database, 100-200 $ / ML permeate produced, averaged value is used to determine the cost. |
| Labour | $M | 8.8 | In-house Aurecon database, 100-200 $ / ML permeate produced, averaged value is used to determine the cost. |
| Operation and maintenance | $M | 13 | In-house Aurecon database. 200 - 300$ / ML permeate produced, averaged value is used to determine the cost. Average value, including replacement and maintenance of equipment and membranes |

Note that the type of intake and outfall selected for a desalination plant is one of the most important technical considerations for a plant's cost-efficient design and optimum operation. Important factors need to be evaluated such as the most suitable intake type (submerged vs. open intake), the distance of the intake relative to the plant, the type of intake screens, the type of intake structure, the type of intake pipeline (buried vs. above ground), and environmental considerations with regards to impingement and entrainment of marine life. Each of these items has a significant cost impact. To illustrate the potential significance of intake and discharge structure costs, SWRO plant discharges located close to marine habitats that are highly sensitive to elevated salinity require elaborate concentrate discharge diffuser systems, with costs that can exceed 30% of the CAPEX. In contrast, the desalination plants with the lowest water production costs have concentrate discharges either located in coastal areas with very high natural mixing or are combined with power plant outfall structures, allowing good initial mixing and better discharge plume dissipation. The intake and discharge facility costs for these plants can be less than 10 % of the CAPEX.

## 7.2 Water treatment (demineralisation) for hydrogen production

### 7.2.1 Overview

Demineralisation is a water purification process to remove salt and mineral from feedwater to produce highly purified water.

### 7.2.2 Processing technology

The water demineralisation process proposed for different water sources is presented in Table 7-2.

Table 7-2 Demineralisation process for different water source

| Water source | Treatment process to achieve the demineralised quality |
|---|---|
| Seawater | Ultrafiltration + reverse osmosis with energy recovery+ ion exchange/ Electrodeionization (EDI) (See Section 7.1.2 for details) |
| Surface water, dam, river water | Clarification +ultrafiltration, reverse osmosis+ ion exchange/ EDI |
| Recycled water (municipal) - assuming secondary effluent after BNR | Ultrafiltration, reverse osmosis, ion exchange/ EDI |
| Underground/ borewater | Low salinity - Ultrafiltration, ion exchange/ EDI |
| | High salinity - Ultrafiltration, reverse osmosis, ion exchange/ EDI |
| Potable water | Reverse osmosis + Ion exchange/ EDI |

### 7.2.3 Selected hypothetical project

The selected hypothetical project is a demineralised plant (or water treatment plant) to produce highly purified water (ASTM Type **I** or Type **II**) for a 10 MW electrolyser plant using potable water. Relevant process parameter is presented in Table 7-3. Water balance around the demineralised plant is determined using a recovery ratio (RR) similar to a desalination plant as discussed in Section 7.1.2. Typical RR is around 86% with potable water as feedwater. RR would vary with different feedwater source, depending on the water quality.

A major wastewater source for this type of plant is brine. Wastewater from membrane backwash and chemical cleaning (CIP) will also be produced but the volume is minimal when compared to brine production.

Table 7-3 Process parameter of a demineralised plant for a 10 MW electrolyser plant

| Item | Unit | Value | Comment |
|---|---|---|---|
| Demineralised water requirement | $m^3/d$ | 60.0 | In-house Aurecon database |
| Potable water requirement | $m^3/d$ | 69.5 | In-house Aurecon database |
| Brine production | $m^3/d$ | 9.5 | In-house Aurecon database. |
| Power consumption | MWh/day | 1.2 | In-house Aurecon database, 15-30 kWh/m3 permeate water, averaged value is used to determine cost |
| Recovery ratio | % | 86 | In-house Aurecon database |

### 7.2.4 Cost estimate

The following table provides the cost parameters the demineralised plant (or water treatment plant) to produce highly purified water for a 10 MW electrolyser plant using potable water.

Table 7-4 Water treatment plant cost estimate (10 MW electrolyser plant)

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX** | | | |
| CAPEX | $M | 1.3 – 1.6 | In-house Aurecon database. |
| **CAPEX breakdown** | | | |
| ▪ Development cost (including equipment) | % | 10 | |
| ▪ Construction cost | % | 90 | |
| **OPEX - Annual** | | | |
| Power | $ | 5,500-11,000 | In-house Aurecon database |
| Chemical | $ | 1,100-2,800 | In-house Aurecon database |

| Item | Unit | Value | Comment |
|---|---|---|---|
| Labour | $ | 30,000 – 40,000 | In-house Aurecon database, system is fully automated. |
| Operation and maintenance | $ | 16,000 -27,500 | In-house Aurecon database. Average value, including replacement and maintenance of equipment and membranes |

# 8 Hydropower and PHES

## 8.1 General

Utility scale hydropower (also known as hydroelectric or hydro) schemes harness the energy in water due to flow discharge and head. Head is water level differential between the intake structure and outlet of the turbines. Hydropower technology is utilised for both generation and energy storage, as follows:

- Generation – Also referred to as conventional hydro, these schemes use inflows from a watercourse or river to produce electricity. There are several sub-categories although simplistically they either have no substantial water storage, that is called run-of-river, or they have a reservoir that could store the water for days and months so that it could be used at peak hours. Therefore, reservoir schemes are dispatchable without being intermittent.
- Storage – Pumped Hydropower Energy Storage (PHES) schemes are in essence large-scale water batteries. They consume excess electricity on the grid to pump water to an upper reservoir that sits at a higher elevation compared to the lower reservoir to store the energy. The water then can be released in reverse to the lower reservoir to produce electricity during peak hours which is normally signified by higher prices. Like BESS, the primary input of pumped storage schemes is electricity whilst the water in the scheme is broadly cycled between two reservoirs as a mechanism to store or generate power. These schemes have several sub-categories but simplistically they are either closed-loop or open-loop depending on whether any of the reservoirs is a result of damming a river. It is important to note that depending on the site climate, some water may be required for topping up the system or be released from the system during flood events.

Alongside electricity generation and storage, the flexibility and scale of hydroelectric schemes allows them to provide several grid services, including frequency regulation, spinning reserve, black start, voltage stabilisation, peaking, load levelling and stabilising functions (Var compensation) depending on the size (power – MW or energy – MWh) and type of the scheme. Typically, larger schemes provide more services and to a greater extent or depth within the grid than smaller ones.

Large schemes comprise of significant civil works that include reservoirs/dams, intakes, outlets, waterways that may include pipelines and/or tunnels, powerhouses that may be aboveground or underground, access infrastructure such as roads and tunnels, and power evacuation including transmission infrastructure. Generally, hydroelectric plants benefit significantly from scale (i.e. larger schemes have lower unit costs of power and energy) although for conventional hydropower the catchment yield is a limitation.

Owing to the significant infrastructure requirements, the financial and technical viability of hydroelectric schemes are site specific and are heavily influenced by site topography, geology, hydrology, related water rights, environmental requirements, land use limitations, proximity to the electricity grid, and presence of access infrastructure. The need for significant capital outlays and the requirement for long development periods or lead times counterbalanced by the very long economic life of hydroelectric schemes, means that local, state, and national policies also have a significant impact on the assurance provided to developers of hydroelectric schemes and thus their viability.

## 8.2 Conventional hydropower

### 8.2.1 Overview

Hydroelectricity is a mature technology proven over nearly one and half centuries now and remains the largest source of renewable electricity generation, globally. It has among the best resource conversion efficiencies at about 90% – water to wire, and with relatively small maintenance and rehabilitation efforts, schemes remain operational for more than eighty years.

### 8.2.2 Typical options

Whilst planning and developing viable generation hydroelectric schemes includes a synthesis of various inputs, the topography and hydrology of a given site are the primary resource inputs that dictate how much hydroelectricity can be realised. Thus, utility-scale run-of-river and reservoir hydroelectric schemes have installed capacities ranging from tens to thousands of megawatts. Globally, there are several schemes with more than 10,000 MW installed capacity. However, Australia being the driest continent in the world, its potential for conventional hydropower is limited, most of which has already been harnessed. The 950 MW Murray 1 power plant, in the Snowy Hydro scheme is the largest operational station.

### 8.2.3 Recent trends

Given the long construction time of conventional hydroelectric plant and complexities associated with environmental approval, prospects of constructing new conventional hydroelectric plants in Australia are very limited. However, significant opportunities may be found in upgrading or expanding existing plants to improve their output and/or installing plants on existing water infrastructure that is not equipped with generating equipment i.e., exploiting the so-called hidden hydro. Annex XVI of the International Energy Agency's hydropower/hydroelectricity group advocates and provides information on hidden hydro. In this vein, the planned redevelopment of the Tarraleah scheme in Tasmania that will increase output from some 100 MW to some 220 MW with 20 hours of reservoir storage can be considered.

Globally, more variable renewable energy generation is being installed to help reduce the progress of carbon emissions induced climate change. To gain synergies between alternative renewable technologies, hybrid power plants or power plant parks are being proposed where such technologies operate collectively for an optimised solution. One such pairing, that is likely to gain traction with time, is between existing reservoir hydroelectricity schemes and floating solar PV. In such developments, solar panels are placed on the reservoir and thus use existing hydroelectricity real estate and grid connection whilst the reservoir scheme profits from supplemental generation especially when water flows are low and, if a significant area is covered by the panels, potential reduction in evaporation losses. At the 340 MW Urrá hydroelectricity plant in Colombia, a pilot 1.5 MW floating solar system was installed to supply the auxiliary loads of the hydroelectricity plant.[90] Similar installations could help in reducing the running costs of existing plants and, if further advanced to appropriate scales, provide additional generation on the grid.

### 8.2.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project upon which costing is based. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2024 ie exploitation of hidden hydro by refurbishing or redeveloping aged schemes, given the above discussion on typical options and current trends.

**Table 8-1 Configuration and performance**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology / OEM | | Francis Turbine | Several OEMs exist including Andritz, GE Vernova, Voith Siemens, Toshiba, Hitachi Mitsubishi |
| Make model | | Various | Supplier specific and customised to site |
| Unit size (nominal) | MW | 50 | ISO / nameplate rating |
| Number of units | | 2 | Typical minimum number for Francis units |
| **Performance** | | | |
| Total plant size (Gross) | MW | 100 | |

[90] https://www.hydroreview.com/environmental/noria-energy-launches-floating-solar-project-at-colombias-urra-dam/

| Item | Unit | Value | Comment |
|---|---|---|---|
| Auxiliary power consumption | - | 1% | Of power at transformer HV terminals. Less than 1% to 2% depending on balance of plant, distance from metering point to power transformers, etc. |
| Total plant size (Net) | MW | 99 | |
| Seasonal rating – Summer (Net) | MW | 99 | Net output only depends on available flow from river or reservoir |
| Seasonal rating – Not Summer (Net) | MW | 99 | Net output only depends on available flow from river or reservoir |
| **Annual Performance** | | | |
| Average planned maintenance | Days / year | 7 | |
| Equivalent forced outage rate | - | 2% (varies between 1%-2%) | For typical overall plant availability of 98% |
| Effective annual capacity factor (P50, year 0) | - | 32% | Based on nominal capacity. Value is Australasia/Oceania regional average from IPCC 2011 - Hydropower |
| Annual generation | MWh | 280,000 | Provided for reference. |
| Annual degradation over design life | - | 0.1% pa | Assuming straight line degradation, i.e., proportion of initial energy production. |

**Table 8-2 Technical parameters and project timeline**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **Technical parameters** | | | |
| Ramp up rate | MW/s | 5 | Based on 10s for full load of each unit |
| Ramp down rate | MW/s | 5 | Based on 10s for full load of each unit |
| Start-up time | Min | 1-2 | Start-up time of each unit to full capacity. Simultaneous start of units is typically not practical or designed for. |
| Min stable generation | % of installed capacity | 40% | |
| **Project timeline** | | | |
| Time for development | Years | 2 – 4 | Includes feasibility assessment, design, approvals, etc. to Financial close / Final Investment Decision.<br>Where upgrade works do not include extensive civils works (e.g., upgrade of electromechanical equipment only), the lower end of the range is more appropriate. |
| First year assumed commercially viable for construction | Year | 2024 | Very mature technology |
| EPC programme | Years | 3 – 5 | For NTP to COD, depending on extent of upgrade / refurbishment |
| ▪ Total lead time | Years | 1-2 | Construction and turbine supply, and operation are intertwined, although the first unit may start operations a year to six months earlier |
| ▪ Construction time | Years<br>(Weeks) | 2-3<br>(100-150) | Construction and turbine supply, and operation are intertwined, although the first unit may start operations a year to six months earlier |

| Item | Unit | Value | Comment |
|---|---|---|---|
| Economic Life | Year | 30 to 50 | Plants usually last a very long time. Economic life is therefore often assigned by the discounting rate applied in a project's economic / commercial analysis. Typically, private developers apply higher rates which show lower economic life whilst public developers may apply lower rates that show higher economic life. |
| Design Life | Years | 80 to 100 | Electro-mechanical elements are usually designed for some 40-50 years whilst civil infrastructure is designed for 100 years. Major refurbishment of Electro-mechanical elements usually occurs at 25-30 years intervals to ascertain suitability of operation. None the less, the facility as a whole is expected to last for more than 80 years. |
| Technical Life (Operational Life) | Years | 80 to 100 | Includes site specific assessment and life extension but not repowering for electrical package / civil infrastructure |

### 8.2.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 8-3 Cost estimates**

| Item | Unit | Value | Comment |
|---|---|---|---|
| **CAPEX Construction** | | | |
| Relative cost | $ / kW | 5,250 | Based on Aurecon internal benchmarks. There has been an ongoing increase in turbine prices in the last 12-24 months despite the easing of shipping constraints, removal of supply chain bottlenecks, and stabilisation of commodity price movements. Relative cost does not include land and development costs. |
| Total cost | $ | 525,000,000 | |
| ▪ Equipment cost | $ | 105,000,000 | ~20-30% of overall costs |
| ▪ Civil and other cost | $ | 420,000,000 | ~70-80% of overall cost |
| **Other costs** | | | |
| Other development cost (eg, land and development) | $ | 52,500,000 | Assuming ~10% of total costs |
| Fuel connection costs | $ | N/A | |
| **OPEX – Annual** | | | |
| Fixed O&M Cost | $ / MW (gross) | 105,000 | Average annual cost over the design life. O&M costs typically increase steadily over the project life. |
| Variable O&M Cost | $ / MWh (gross) | - | Included in the fixed component. |
| Total annual O&M Cost (includes fixed and variable costs) | $ | 5 to 15M (average 10M) | Annual average cost over the operating life. |

## 8.3 Pumped hydroelectric storage (PHES)

### 8.3.1 Overview

Pumped Hydropower Energy Storage (PHES) utilises the same technology as conventional hydro to provide dispatchable electricity but adds a reverse mode for pumping that enables the facility to store energy when there is excess generation on the grid. Globally, PHES is also referred to as Pumped Storage Plant (PSP), Pumped Storage Hydropower (PSH), Pumped Hydro Storage (PHS), Pumped Storage, or even Pumped Hydro. More than 90% of the world's electricity storage is provided by PHES.

### 8.3.2 Typical options

Amongst the many ways PHES may be implemented, options regarding a scheme's water circuit (open or closed loop) and primary energy conversion equipment are amongst the major ones to influence a plant's costs and performance.

Open loop systems have a direct connection to a watercourse (river or lake) and rely on it to provide first fill water for charging the scheme and top up water to make up for evaporation and infiltration losses from the system. Typically, such inflow to the system is by the watercourse flowing into the lower reservoir of a PHES. Closed loop systems, on the other hand, do not have such a direct connection to a water course and, thus, first fill and top up water is delivered to the scheme through dedicated infrastructure (abstraction and pipelines) from a nearby watercourse. The water is supplied to the scheme as and when needed. Therefore, open loop systems generally require less infrastructure and provide greater assurance of the availability of water for the scheme and can be less expensive in that sense. However, open loop systems potentially impact watercourses and the users of such watercourses more and therefore can be more onerous to plan and permit.

Key equipment options include the pumping / generating arrangement (reversible units, ternary sets, and dedicated pumps and turbines) and the type of speed regulation of units (fixed speed, variable speed, "hydraulic short circuit"). Plants with reversible units provide the most compact powerhouse civil works, followed by ternary sets, and then dedicated pumps and turbines. The dedicated units are no longer common due to this demerit. However, flexibility of operation is reversed among the options i.e., dedicated units are more flexible than ternary sets which are more flexible than reversible units. Variable speed units alter their rotational speed to run at the best possible efficiency and thus have a wider operating range than fixed speed units especially when pumping. Such increased flexibility allows for more energy and grid services capability but at increased equipment and civil works costs.

### 8.3.3 Recent trends

Like conventional hydro, upgrading of existing plants to achieve more utility out of them and using hydropower assets to firm variable renewable energies are areas of interest for PHES. Moreover, by adopting closed-loop systems, the favourable scale and economies of PHES can be exploited even in the driest continent in the world.

To support the energy transition to cleaner but variable renewables such as solar and wind, many PHES projects are being developed across the globe. In Australia, these include the 2,000 MW / 350,000 MWh Snowy 2.0 and the 240 MW / 2,000 MWh Kidston projects under construction with several others across the country in the development stage. Whilst the former is an open-loop system utilising existing reservoirs, the latter is a closed-loop system being developed at an end-of-life mine.

PHES is being looked at for medium to long term storage options for NEM deployment. In 2017 several projects were proposed in SA with scale of 200-300 MW and 8-12 hours storage. Since then, multiple projects have been proposed across different NEM jurisdictions with majority of proposed projects in QLD and NSW. Scale of PHES schemes being proposed have also increased, with projects ranging in scale from 300 to 5,000 MW capacity that have intraday (one full cycle within a day; so, less than 11 hours) or interday (one full cycle spanning over more than two days; so, more than 24 hours). Interestingly, the government-led developments trend towards GW+ with interday duration whilst the private-led developments are 100 MWs with intraday cycles.

With advancements in BESS technology, BESS is expected to provide short to medium term (≤ 8 hours) storage whilst new PHES developments are tending towards 10+ hours to more than 24 hours of storage. Selection of capacity and storage is dependent on both site factors as well as the intended operating purpose and "fit" to owner or offtaker portfolio and end customer base.

Should the rather large utility-scale BESS technology projects advance further with $/MWh reduction or stabilisation they may soon displace the sub-GW intraday PHES developments given the significant risks and uncertainties associated with environmental permitting, water licencing, and cost/time blow out uncertainties for venture capital investors. Governments seem to be more equipped with tools to develop large-scaled PHES projects until they reach financial close at which point private sector could get involved in a PPP arrangement.

In addition to the Snowy 2.0 and Kidston projects under construction, publicly announced projects include:

- Borumba - 2,000 MW / 24 hours
- Pioneer-Burdekin - 5,000 MW / 24 hours
- Muswellbrook - 250 MW / 8 hours
- Oven Mountain - 600 MW / 12 hours
- Central West - 325 MW / 8 hours
- Lake Lyle - 335 MW / 8 hours

There are also several other projects under development.

The development of PHES in end-of-life mines is a recent development that extends the usefulness of mine infrastructure by giving it a new lease of life as a PHES scheme. The PHES project would typically get at least one pit to be modified into a reservoir, access and water supply infrastructure and possibly land and water access rights. Some of the mine's closure budget may also be attributed to the PHES potentially making such a scheme of interest. Mine PHES also has the benefit of fewer new environmental impacts as it is developed on already disturbed sites which potentially makes for easier mitigation of new impacts and easier permitting.

Nonetheless, such schemes also come with their own challenges that need to be well planned for including the high likelihood of poor water quality related to acid rock drainage (especially for gold mines, the geology in platinum mines tends to be favourable). Additionally, having to fit the PHES into pits or stopes whose geometry is not developed for retaining water with long-term level fluctuations poses a challenge in ensuring that water loss is minimal and that reservoir slopes are stable.

The relatively steep geometries of mine pits and/or stopes also lead to increased water level variations during plant operation increasing the head range of PHES beyond what reversible fixed speed units, which are the contemporary choice, can accommodate. Therefore, if modifying the geometry of the pits and/or stopes is not sufficient to provide a workable solution, alternative turbine technologies that can accommodate higher variations in head such as variable speed units or fixed speed multi-stage units may be adopted. The alternative units attract higher equipment costs and for variable speed units, a lack of natural inertia has been seen as unfavourable especially where big synchronous coal generators are being decommissioned.

For the latter, PHES with virtual inertia akin to grid forming batteries (see Section 9.2.3 below) allows for the benefits of variable speed technology to be exploited whilst still providing system strength. A recent development in the technology is the commissioning of the world's first Fully Fed AC/AC Modular Multilevel Converter (MMC) for PHES at the 2 x 80 MW Malta Oberstufe Pumped Storage Hydropower Plant in Austria[91]. Scalable AC/AC MMC technology is proven in railway power supply and is expected to increase

[91] A. Christe, A. Faulstich, M. Vasiladiotis, and P. Steinmann, World's first fully rated direct ac/ac MMC for variable-speed pumped-storage hydropower plants, IEEE transactions on industrial electronics, February 2023

the size limit of fully converter fed PHES units from some 100 MW to some 400 MW[92] whilst providing high torque over a wide operating range starting from standstill, smaller motor-generator units, faster and simpler turbine – pumping mode transitions, higher plant cycle efficiency, and power balancing during pumping.

### 8.3.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM, given the above discussion on typical options and current trends.

**Table 8-4 PHES configuration and performance**

| Item | Unit | 10 hours | 24 hours | 48 hours | Comment |
|---|---|---|---|---|---|
| **Configuration** | | | | | |
| Fixed speed reversible units | | | | | |
| **Capacity** | | | | | |
| Power Capacity (gross) | MW | 500 | 2,000 | 2,000 | Current projects under development range from 300 to 5,000 MW |
| Plant net power output | MW | 495 | 1980 | 1980 | |
| Seasonal ratings summer typical (net) | MW | 495 | 1980 | 1980 | 35°C, 110 metres, 60%RH |
| Seasonal ratings not summer (net) | MW | 495 | 1980 | 1980 | 15°C, 110 metres, 60%RH |
| Minimum stable generation | % | 40 | 40 | 40 | |
| Energy Capacity | MWh | 5,000 | 48,000 | 96,000 | Current projects typically consider storage of 10 hours or less for private developers or above 24 hours for government led projects |
| **Annual Performance** | | | | | |
| Average Planned Maintenance | Days / yr. | 7 – 15 days | 7 - 15 days | 7 - 15 days | Plants with multiple units will increasingly have lower average planned maintenance outages as unit(s) that would be out for maintenance represent a smaller portion of the plant's capacity. |
| Equivalent forced outage rate | % | 1 - 2 | 1 - 2 | 1 - 2 | Dependent on level of long-term service agreement, retention of strategic spares etc. |
| Annual number of full cycles | | 300 | 150 | 75 | The plant will most of the time operate in partial cycles rather than full cycle |

[92] M. Basic, P. Silva, and D. Dujic, High Power Electronics Innovation Perspectives for Pumped Storage Power Plants, Hydro 2018, IEEE

| Item | Unit | 10 hours | 24 hours | 48 hours | Comment |
|---|---|---|---|---|---|
| Annual energy storage degradation over design life | % | <0.1% | <0.1% | <0.1% | As the friction losses increase in waterways linings, they will get recoating to restore the smoothness.<br>Similarly, regular equipment maintenance and major refurbishments every 30 years will ensure that the unit efficiencies are not dropped. |

**Table 8-5 Technical parameters and project timeline**

| Item | Unit | 10 hours | 24 hours | 48 hours | Comment |
|---|---|---|---|---|---|
| **Technical parameters** | | | | | |
| Ramp Up Rate | MW/hr | 10,000+ | 10,000+ | 10,000+ | 0 to 100% rated MW capacity depends on the technology. Regardless it is far less than the 5 minutes market settlement |
| Ramp Down Rate | MW/hr | 10,000+ | 10,000+ | 10,000+ | As above. |
| Auxiliary load | % | 1 | 1 | 1 | |
| Round trip efficiency (Beginning of Life [BOL]) | % | 75-80 | 75-80 | 75-80 | Round trip efficiency varies based on the waterway length and transmission line length and losses. |
| **Project timeline** | | | | | |
| Time for development | Years | 3-5 | 3-5 | 3-5 | |
| Total EPC Programme | Years | 3-6 | 4-8 | 4-8 | |
| Total Lead Time | Years | 1.5-2.5 | 1.5-2.5 | 1.5-2.5 | |
| Construction time | Years | 1.5-3.5 | 2.5-5.5 | 2.5-5.5 | |
| Economic Life | Years | 30 to 50 | 30 to 50 | 30 to 50 | Plants usually last a very long time. Economic life is therefore often assigned by the discounting rate applied in a project's economic / commercial analysis. Typically, private developers apply higher rates which show lower economic life whilst public developers may apply lower rates that show higher economic life. |
| Design Life | Years | 80-100 | 80-100 | 80-100 | Electro-mechanical elements are usually designed for some 40-50 years whilst civil infrastructure is designed for 100 years. Major refurbishment of Electro-mechanical elements usually occurs at 25-30 intervals to ascertain suitability of operation. |
| Technical Life (Operational Life) | Years | 80-100 | 80-100 | 80-100 | Includes site specific assessment and life extension but not repowering for electrical package / civil infrastructure |

### 8.3.5 Cost estimate

PHES project costs vary significantly depending upon various project attributes as discussed in this section of the report. Due to variable nature of PHES project costs, we provided range of prices for both plant configurations. Favourable geotechnical conditions, shorter tunnels, above ground power houses, or existing suitable lower reservoirs may have costs towards the lower end of the range. The following factors could impact on making a project more expensive in terms of $/MW:

- Lower head differential between upper and lower reservoirs
- Smaller installed capacity (economy of scale)
- Out of range net head ratio that requires separate pumps and turbines rather than reversible units
- Unfavourable geology for the surface and underground structures
- Longer transmission line or underground transmission line due to environmental constraints
- Water top-up and initial fill requirements

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 8-6 Cost estimates**

| Item | Unit | 500 MW x 10 hours storage | 2,000 MW x 24 hours storage | 2,000 MW x 48 hours storage | Comment |
|---|---|---|---|---|---|
| **Construction costs for PHES (with dedicated grid connection)** | | | | | |
| Relative cost - Power and storage component | $ / kW | 5,000 – 9,000 | 4,200 to 7,350 | 5,250-8,400 | Depending on the complexity of upper and lower reservoir, and the grid connection this range may change.<br>For the same installed capacity, it is expected that extending the duration increases the cost per kW, as larger reservoirs are needed.<br>Smaller size and duration will have a cost premium per kW of installed capacity. |
| Total EPC cost | $M | 2,500 – 4,500 | 8,400 – 14,700 | 10,500 – 16,800 | Based on announced projects and projects at various stages of development. |
| ▪ Equipment cost | $M | 300 - 750 | 1,050-2,625 | 1,575-2,625 | As above. |
| ▪ Installation cost | $M | 2,200 – 3,750 | 7,350-12,075 | 8,925-14,175 | As above. |
| **Other development costs** | | | | | |
| Land and other development costs | $M | 200 - 400 | 1,050-1,575 | 1,575-2,100 | |
| **OPEX – Annual** | | | | | |
| Fixed O&M Cost | $ / MW (gross) | 95,000 | 73,500 | 84,000 | Average annual cost over the design life. O&M costs typically increase steadily over the project life. |
| Variable O&M Cost | $ / MWh (gross) | - | - | - | Included in the fixed component. |
| Total average annual O&M Cost (Fixed and variable O&M) | $M | 47 | 147 | 168 | Highly variable between OEMs.<br>Indicative annual average cost over the operating life |

It is anticipated that the modern PHES equipment fleet will be under more operational fatigue as it requires to generate and pump more during the day compared to conventional storage hydropower. As such, the annualised O&M cost for PHES (especially for ternary sets) may be higher than conventional hydropower stations, if the same installed capacity is assumed for both.

# 9 Battery Energy Storage System

## 9.1 General

A battery energy storage system (BESS) stores electricity from the network or co-located generation plant, for use at a later point as needed. This section details four BESS types that are relevant to the Australian energy market. These types are:

- large-scale lithium-ion battery storage,
- large scale vanadium redox flow battery storage,
- residential battery storage and
- large-scale iron air battery storage.

## 9.2 Large-scale lithium-ion battery storage

### 9.2.1 Overview

Large scale lithium-ion technology batteries come in many forms. For the purposes of this section, only three types will be identified as they are currently the dominant technologies in Australia. These include lithium nickel-manganese-cobalt oxide (NMC), lithium nickel-cobalt-aluminium oxide (NCA) and lithium iron phosphate (LFP). The battery Original Equipment Manufacturers (OEM) each specialise in a specific technology to try and gain market share with the respective inherent qualities. However as improved performance and manufacturing techniques evolve, it can be seen that the LFP technology is currently replacing the other technologies. This is due to its lower inherent thermal runaway temperature making it a safer option.

A large-scale Battery Energy Storage Systems (BESS) consists of several primary components, including the battery system, battery management system, power conversion stations (bi-directional inverters, step-up transformer(s)), power plant control system and other balance of plant. The BESS can be connected to the grid via AC coupling or if co-located with a solar installation or similar can be connected via DC coupling.

### 9.2.2 Typical options

A large-scale BESS can be used for a wide range of network services as follows:

- Arbitrage (market participation) – buying energy (charging the BESS) at one market price and selling the energy (BESS dis-charge) at another, typically higher, market price.
- Load (generation) shift – Controlling the time of use of the energy stored during high VRE generation periods and releasing at low VRE generation periods.
- Capacity firming – providing energy during variable or intermittent periods of RE generation to stabilise (smooth) the generation. This provides better grid control of voltage and power fluctuations,
- Primary Frequency Response (PFR) – This is the event where the BESS increase or decrease the real power dispatch point to respond to an increase or decrease in frequency. This service has been mandated by AEMO as a compulsory service for all scheduled and semi-scheduled generators since 2020. This type of service also includes Fast Frequency Response (FFR) where the BESS will need to respond within a very short time period typically 2 seconds or less.
- Frequency control (contingency) – This is where the BESS injects or absorbs reactive power to control the frequency during a contingency event (outside of the operating band width). Events of this type include large load or generation trips. This is known as contingency Frequency Control Ancillary Service (C-FCAS). A typical example of this type of service is provided by the Hornsdale Power reserve (HPR) where the installation provides FCAS on a continuing basis.

- Frequency control (regulation) – This is where the BESS injects or absorbs reactive power to control the frequency as part of an ongoing regulation service (within the operating bandwidth). This is known as regulation Frequency Control Ancillary Service (R-FCAS).
- Voltage support – The BESS injects or absorbs reactive power (Q) to support the voltage on the network. This is provided by the four quadrant inverters used for each BESS installation. The four modes are absorbing or injecting Q during charge and absorbing or injecting Q during discharge.
- Black Start – Some BESS installations have ability to be grid forming by configuring their software to provide an internal 50Hz voltage sine wave. With this ability the BESS is able to set a voltage on a blacked-out grid so other generators can synchronise and the grid can recover.
- Spinning reserve displacement – This is a service where energy is held back by the BESS to ensure power support if a generator trips or fails to meet their allocation and there is a shortfall in the market generation.
- Synthetic inertia – This service is when the BESS can supply power to the grid during a fault event such that the grid protection systems can operate reliably. This beneficial in systems where there is a lot of VRE generation.
- System strength – Part of the grid forming BESS ability is to provide additional power/energy (generation) to improve the strength of the grid by providing voltage and frequency stability. This can counter act any oscillatory actions by other grid following VRE generation.
- Islanding – Similar to the black start capability in that during a grid black out, a grid forming BESS can keep the “lights on” and ensure the grid or section (island) of the grid continues to operate.
- Peak shaving – During periods of high VRE generation (eg Roof top solar in the middle of the day) the BESS can absorb energy and store it for discharge at a later time when VRE generation is low.
- System integrity protection systems (SIPS) – Because of the intrinsic speed of a BESS, it can inject power very quickly. This can be used to control overloading of transmission lines prior to the line tripping. This reduces the need for load shedding post trip. This helps to maintain a grid that is more stable and robust. A BESS can also be used to protect NEM interconnectors or increase transfer flows, with examples including the following:
  - Hornsdale Power Reserve and the Dalrymple BESSs participating in the SIPS of the SA-Vic Heywood interconnector and
  - the Victorian Big Battery is contracted to provide a SIPS service for the Vic-NSW interconnector (VNI)
- Power factor support – The BESS ability to inject or absorb Q allows it to support the power factor of the grid which supports the voltage.
- Reliability improvement – BESS installations can provide further direct support to loads during periods of short but large load increase such as large motor start ups at mine sites etc.
- Fuel savings – For some installations where there are multiple small rotating (diesel) generators (for variable loading eg a mine site), a BESS can be used during periods of small load increase. This saves the need for another generator to start up when one is at full capacity. This then reduces the number of generators that are required to be used, which saves fuel.

The modular nature of a BESS enables it to be sized in both power and energy to meet highly specific and varied project requirements. It is common practise to perform detailed network technical studies to identify the services that the BESS can be utilised for. This then allows the Developers to understand how big the BESS can be sized in relation to power and duration. Currently in Australia the BESS size is typically 200MW and 400MWh (2 hour storage) with recent significant pressure to up scale.

### 9.2.3 Recent trends

#### Development pipeline

Aurecon is currently aware of 371 BESS projects currently in-service, being developed or announced (pipeline) across Australia. Of these 30 large-scale Li-ion BESS are operating (in-service) within Australia, with the largest being the 300 MW / 450 MWh Victoria Big Battery in Victoria. Twenty-five of these systems are connected to the National Electricity Market (NEM), with the other five batteries in remote locations. One of these is the 100 MW / 200 MWh Kwinana BESS connected to the South-West Interconnected System and the other four are smaller batteries located at remote mine sites.

Further large-scale BESS are currently under construction, ranging in size from the 10 MW / 10 MWh Lincoln Gap BESS to the 850 MW / 1680 MWh Waratah Super Battery, with many more projects in the development pipeline[93]. The Waratah Super Battery, due to be constructed in 2025, will be located at the site of the old Munmorah coal-fired power in NSW and will become one of the largest BESSs in the world, with its capacity largely serving a SIPS Contract for the NSW Government.

Some recently commissioned BESS installations in Australia and those expected to be constructed in 2024 include[94]:

- Torrens Island (SA) – 250 MW / 250 MWh (operational)
- Hazelwood (Vic) – 150 MW / 150 MWh (operational)
- Chinchilla (Qld) – 100 MW / 200 MWh (operational)
- Kwinana (WA) – 100 MW / 200 MWh (operational)
- Bouldercombe (Qld) – 50 MW / 100 MWh (operational)
- Darwin (NT) – 35 MW / 35 MWh (constructed)
- Latitude Solar Battery (NSW) – 5 MW / 11 MWh (operational)
- Broken Hill (NSW) – 50 MW / 50 MWh (operational)
- Western Downs (Qld) – 270 MW / 510MWh (operational)
- Blyth (SA) – 200 MW / 400 MWh (in construction)
- Greenbank (QLD) – 200 MW / 400 MWh (in construction)
- Capital Battery (ACT) – 100 MW / 200 MWh (in construction)
- New England (NSW) – 50 MW / 60 MWh (in construction)
- Tom Price (WA) – 45 MW / 12 MWh (in construction)
- Tailem Bend II Hybrid (SA) – 41.5 MW / 41.5 MWh (in construction).
- Waratah Super Battery (NSW) – 850 MW / 1680 MWh
- Collie 1 (WA) – 340 MW / 1363 MWh (in construction)

The current fleet of operating large-scale BESS incorporate an average of 1.56 hours of energy storage (weighted by plant power rating), which is an increase from 1.4 hours in 2023. Of the current pipeline that Aurecon is aware of, the average stored capacity is 1.86 hours. The average storage capacity is expected to increase towards 2.3 hours in the coming years (considering in construction and announced projects) and will include systems with up to 8 hours of storage. Of the projects under construction in Australia, ten integrate storage durations of greater than 2 hours. The trend towards longer storage durations is consistent with expectations associated with falling battery prices in the medium to long term and a likely shift towards arbitrage as a primary BESS application on the NEM.

The large-scale BESS development pipeline demonstrates an increase in BESS power capacities, with the average power capacity of BESS projects increasing from under 100 MW for assets operating today to

[93] https://reneweconomy.com.au/big-battery-storage-map-of-australia/
[94] https://reneweconomy.com.au/big-battery-storage-map-of-australia/

above 200 MW for projects that are in construction or have been announced [76]. In line with this trend towards larger BESS capacities, Aurecon has considered a 200 MW BESS as the basis for the hypothetical project considered in Sections 9.2.4 and 9.2.5. However, the technical and cost attributes can be scaled to represent other power capacities as needed.

BESS projects are trending towards longer lifetimes, with developers increasingly considering an operational lifetime of 25 years (5 years beyond expiration of a typical battery extended warranty). Repowering BESS projects out to a total lifetime of 50 years is also being considered for some projects but does not form part of the core business case for these projects.

## Costs

Capital cost of battery energy storage has decreased over the 2023/24 financial year period. As shown in Figure 9-1 below, there was a steady increase in the costs for energy storage from 2021 to 2023 with the peak being in 2023. However, in this last year (2024), there has been a significant decrease in the cost. For a one hour storage duration the cost decreased by 10%. This decrease, increased proportionally for the two, four and eight hour durations, with the maximum being 34% drop for the eight hour duration. The average decrease across the 1 to 8 hour storage durations, inclusive of the substation, being 23%. It is Aurecon's opinion that this decrease was substantially brought about by the reduction in lithium carbonate price. By July 2024 this price had fallen.to approximately 30% of the July 2023 price. The 2024 costs are nearly back to the 2021 costs.

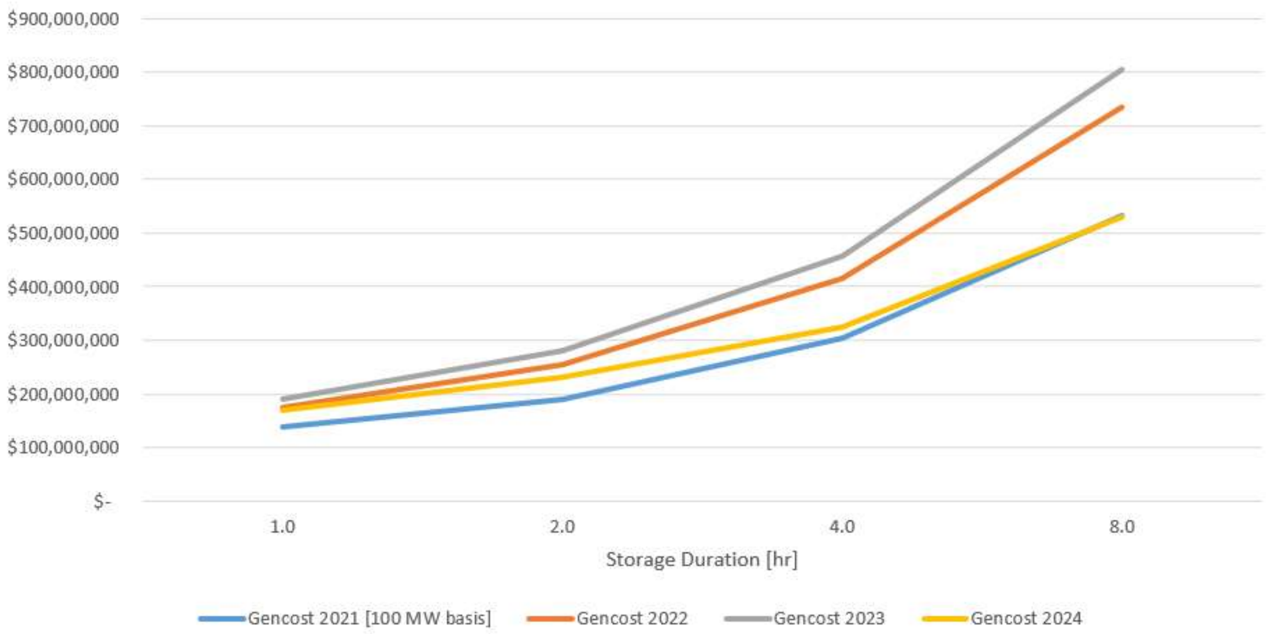


**Figure 9-1 Aurecon internal energy storage cost estimates**

Operations and maintenance (O&M) contracts are both location and project application specific. There is a wide range of O&M costs being offered by the market based on different contracts and pricing structures. A large component of O&M cost is labour and spare parts and some efficiencies in costs may be achieved as the systems and capabilities of O&M providers improve. Aurecon's updated 2023 analysis of BESS O&M costs includes extra data points which have resulted in inclusion of apparent outlier data from 2022; as such, estimated average O&M costs have increased significantly. Aurecon notes that both the estimates from 2022 and 2023 fall within the large range of expected O&M costs of AUD $2-15/kWh.

## Applications

BESS projects are being developed by a range of electricity sector players, including generators, transmission and distribution operators, renewable energy developers and C&I customers (particularly in the mining industry). Proponents of large-scale renewable plants (ie, solar and wind farms) are also increasingly interested in large-scale BESS integration for co-location at the same grid connection point. For co-located installations developed to date, the BESS is typically arranged to be AC coupled to the variable renewable energy generator. There are some development synergies associated with GPS studies, reduced losses and development approvals when developing BESS projects in parallel with VRE projects. However, in the last twelve months there has been interest in BESS being DC coupled with a solar farm. Waroona Solar Farm/BESS and Blind Creek Solar Farm are examples of this type of project inter-connection. Both projects are connecting individual BESS containers to the DC side of the inverter via DC/DC converter. See Section 9.2.1 above. The Developer has chosen to do this as it has calculated that it will reduce charging losses.

When a BESS installation is inter-connected (AC coupled or DC coupled) with another VRE generator, the combined system is called a hybrid BESS-RE system. AEMC reforms, which will take effect from mid-2024 will enable hybrid BESS-RE systems to be registered under a single Integrated Resource Provider (IRP) category, which will further encourage co-location of BESS plants with solar and wind projects. These configurations have the potential to result in better utilisation of fixed or existing infrastructure and reduced VRE energy production losses. These losses include general electrical charging losses and inverter clipping losses for PV plants.

The AEMC is also considering applying more stringent requirements for Primary Frequency Response (PFR) by requiring PFR to be provided by a BESS connected to the NEM at all times. This may result in adverse financial impacts due to the resulting increased battery cycling/energy throughput. This impact is however expected to be at least somewhat offset by another reform, being the introduction of double-sided frequency performance payments for the allocation of regulation FCAS costs, which is due to commence on 8 June 2025. The implication of this is that PFR provided by a BESS can potentially provide an additional (modest) revenue source.

Due to restrictions placed on generators in South Australia by the Office of the Technical Regulator and the advent of the Fast Frequency Response (< 1 second) FCAS market in October 2023, many generators are also increasingly looking to install battery systems with their generation to meet Fast Frequency Response (FFR) requirements. The 'Very Fast' FCAS market is expected to be beneficial for battery systems as it better values the inherent fast-ramping capabilities of Li-ion BESS.

There is considerable interest in large-scale BESS being implemented with advanced 'grid forming' inverters, particularly for the provision of inertia and system strength support. Grid-forming inverters are able to operate independently from synchronous generation and provide a greater role in supporting grid stability. In a recent internal review, it was noticed that there are 22 grid forming BESS system currently in-service or being developed, with 3 grid following systems expected to be retrofitted for grid forming in the future.

With 341 BESS projects in the development pipeline, it is expected that many will have grid-forming capability. This is expected to become the normal operating mode for batteries in the coming years, as grid connection barriers are overcome. In particular, projects are highly incentivised to be implemented in grid forming mode to avoid system strength charges under the new system strength framework.

It is expected that Developers will also place more emphasis on the technical capabilities of the BESS systems to maximise the different revenue avenues available. This includes ancillary market for inertia. This market does not exist at the moment, but it is expected to be, as spinning reserve decreases.

### 9.2.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical AC coupled project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM, given the above discussion on typical options and current trends.

**Table 9-1 BESS configuration and performance**

| Item | Unit | 1 hour | 2 hours | 4 hours | 8 hours | Comment |
|---|---|---|---|---|---|---|
| **Configuration** | | | | | | |
| Technology | | Li-ion | | | | |
| **Performance** | | | | | | |

| Item | Unit | 1 hour | 2 hours | 4 hours | 8 hours | Comment |
|---|---|---|---|---|---|---|
| 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 | Based on Aurecon internal database of similarly sized projects,<br>Indicative figures (highly dependent on BESS arrangement, cooling systems etc.). |
| Auxiliary load | % | 0.85 | 0.95 | 1.2 | 1.75 | Based on auxiliary power consumption (operating) |
| Auxiliary load | % | 0.15 | 0.3 | 0.6 | 1.2 | Based on standby auxiliary power above |
| 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. Potentially no de-rate, or up to approx. 4% at 35°C. |
| Seasonal Rating – Not Summer (Net) | MW | 198.3 | 198.1 | 197.6 | 196.5 | |
| **Annual Performance** | | | | | | |
| Average Planned Maintenance | Days / yr. | - | | | | Included in EFOR. |
| Equivalent forced outage rate (EFOR) | % | 1 - 2 | | | | Dependent on level of long-term service agreement, retention of strategic spares etc. |
| Annual number of cycles | | 365 | | | | Typical default assumption is on average one cycle per day. However, this is highly dependent on functional requirements and operating strategy. |
| Annual energy storage degradation over design life | % | 1.8 | | | | Indicative average annual degradation figure provided for 20-year BESS, assuming LFP battery chemistry. Significant range dependent battery supplier, or approx. 60 – 65% energy retention after 20 years (based on one cycle per day). Degradation dependent on factors such as energy throughput, charge / discharge rates, depth of discharge, and resting state of charge. |

| Item | Unit | 1 hour | 2 hours | 4 hours | 8 hours | Comment |
|---|---|---|---|---|---|---|
| Annual RTE degradation over design life | % | 0.2 | | | | Indicative average annual RTE degradation figure provided for 20-year BESS (resulting in total of approx. 4% reduction in RTE over project life), assuming LFP battery chemistry. Significant range of 2-6% total degradation in RTE after 20 years (based on one cycle day) observed across different battery suppliers. |

Table 9-2 Technical parameters and project timeline

| Item | Unit | 1 hour | 2 hours | 4 hours | 8 hours | Comment |
|---|---|---|---|---|---|---|
| **Technical parameters** | | | | | | |
| Ramp Up Rate | MW/min | 10,000+ | | | | 0 to 100% rated MW capacity within less than a second (150 ms typical however for specific applications higher performance is available). |
| Ramp Down Rate | MW/min | 10,000+ | | | | As above. |
| Round trip efficiency (Beginning of Life [BOL]) | % | 84 | 84 | 85 | 85 | Typical round trip efficiency (@ BOL), at the point of connection (including auxiliaries), for a full cycle of charge and discharge |
| ▪ Charge efficiency (BOL) | % | 92 | 92 | 92.5 | 92.5 | Assumed to be half of the round-trip efficiency. |
| ▪ Discharge efficiency (BOL) | % | 92 | 92 | 92.5 | 92.5 | Assumed to be half of the round-trip efficiency. |
| Allowable maximum state of charge (SOC) | % | 100 | | | | Performance and costs presented relate to the useable BESS energy storage capacity / state of charge (SOC), with operation permissible throughout this full range.<br>Some battery OEMs quote battery capacity inclusive of unusable capacity. For these OEMs a max and min SOC of 90% and 10% respectively could be expected. It is not however necessary to apply these adjustments to the performance and cost figures presented in this report. |
| Allowable minimum state of charge (SOC) | % | 0 | | | | As above. |

| Item | Unit | 1 hour | 2 hours | 4 hours | 8 hours | Comment |
|---|---|---|---|---|---|---|
| Maximum number of cycles | | 7,300 | | | | Typical warranty conditions based on one cycle per day for 20 years for LFP batteries. Warranties to cover a 20-year battery life may incur additional cost, as indicated herein.<br>Design life for lithium-ion deployed on large scale BESS projects varies from approx. 3,650 to 7,300 depending on the application and lithium-ion battery chemistry. |
| Depth of Discharge | % | 100 | | | | 100% in terms of typically defined 'useable state of charge.' |
| **Project timeline** | | | | | | |
| Time for development | Years | 1-2 | | | | |
| Total EPC Programme | Years | 1.6 | 1.8 | 2.0 | 2.2 | For NTP to COD. |
| ▪ Total lead time | Years | 1.0 | 1.2 | 1.4 | 1.6 | |
| ▪ Construction time | Weeks | 44 | 52 | 60 | 68 | Significantly dependent on BESS arrangement. |
| Economic Life (Design Life) | Years | 20 | | | | Dependent on battery chemistry. 20 years available at one cycle per day with LFP batteries, which are of increasing prominence in large scale BESS proposals. Warranties to cover a 20-year battery life may incur additional cost, as indicated herein. |
| Technical Life (Operational Life) | Years | 20 | | | | Life may potentially be extended to approx. 25 years depending on condition assessment after initial 20-year life. Thereafter potential to extend project life with battery upgrades. |

### 9.2.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 9-3 Cost estimates**

| Item | Unit | 1 hour | 2 hours | 4 hours | 8 hours | Comment |
|---|---|---|---|---|---|---|
| **CAPEX – EPC cost for 200 MW BESS (with dedicated grid connection)** | | | | | | |
| Relative cost - Power component | $ / kW | 526 | 526 | 525 | 522 | Indicative cost for power related components and other costs independent of storage duration |
| Relative cost - Energy component | $ / kWh | 326 | 314 | 274 | 266 | Indicative cost for energy related components |
| Total EPC cost | $M | 170.5 | 230.8 | 324.1 | 530.0 | Based on Aurecon internal database of similarly sized projects and scaled for additional energy storage capacity. |

| Item | Unit | 1 hour | 2 hours | 4 hours | 8 hours | Comment |
|---|---|---|---|---|---|---|
| ▪ Equipment cost | $M | 141.3 | 191.3 | 268.6 | 439.3 | As above. |
| ▪ Installation cost | $M | 29.2 | 39.5 | 55.5 | 90.7 | As above. |
| **CAPEX – EPC cost for 200 MW BESS (co-located with large renewable installation)** | | | | | | |
| Relative cost - Power component | $ / kW | 471 | 471 | 471 | 471 | Indicative cost for power related components and other costs independent of storage duration |
| Relative cost - Energy component | $ / kWh | 326 | 314 | 274 | 266 | Indicative cost for energy related components |
| Total EPC cost | $M | 159.3 | 219.7 | 313.3 | 519.7 | Based on an estimated $10,000,000 savings in transformer and associated grid voltage equipment (ie cost worn by co-located project) |
| ▪ Equipment cost | $M | 132.0 | 182.1 | 259.7 | 430.8 | As above. |
| ▪ Installation cost | $M | 27.3 | 37.6 | 53.6 | 88.9 | As above. |
| **Other costs** | | | | | | |
| Cost of land and development | $ | 10,000,000 | | | | |
| **OPEX – Annual** | | | | | | |
| Fixed O&M Cost | $/MW (Net) | 5,400 | 8,000 | 12,800 | 22,500 | Provided on $/MW basis for input into GenCost template only. |
| Variable O&M Cost | $/MWh (Net) | - | - | - | - | BESS long term service agreements not typically based on fixed / variable. |
| Total annual O&M Cost (excluding extended warranties) | $k | 1,080 | 1,600 | 2,560 | 4,500 | Highly variable between OEMs.<br>Indicative annual average cost over the design life<br>Does not include battery replacement cost at end of Economic Life (Design Life) |
| Extended warranty (20-year battery life) | $/MW (Net) | 3,600 | 5,300 | 8,400 | 14,800 | Indicative annual average cost for 20-year extended warranties for LFP batteries |
| Total annual O&M Cost (extended warranties) | $k | 720 | 1,060 | 1,680 | 2,960 | Highly variable between OEMs.<br>Indicative annual average cost over the design life |
| Total annual O&M Cost (Fixed O&M + extended warranties) | $k | 1,800 | 2,660 | 4,240 | 7,460 | Highly variable between OEMs.<br>Indicative annual average cost over the design life |

# 9.3 Vanadium redox flow battery storage

## 9.3.1 Overview

Large-scale vanadium-redox flow batteries (VRFB) have the potential to complement lithium-ion and other storage technologies in medium duration energy storage applications. Assessment of this technology is presented in the following sections to provide indicative performance and cost data for a battery technology potentially capable of storage durations of 24 and 48 hours. It should be noted that no VRFB projects have been built or proposed at storage durations approaching these levels. With vanadium-redox being a ‘pure flow’ variant of flow battery technology (with energy storage capacity de-coupled from power rating), it appears possible that it could potentially be developed at such storage durations if required. This would however require further development by VRFB OEMs.

## 9.3.2 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM, given the above discussion on typical options and current trends.

**Table 9-4 Vanadium-redox BESS configuration and performance**

| Item | Unit | 24 hours | 48 hours | Comment |
|---|---|---|---|---|
| **Configuration** | | | | |
| Technology | | Vanadium-redox flow | | |
| **Performance** | | | | |
| Power Capacity (gross) | MW | 200 | | |
| Energy Capacity | MWh | 4,800 | 9,600 | |
| Auxiliary power consumption (operating) | MW | 12 | 12 | Indicative figures (highly variable, dependent on BESS arrangement, cooling systems etc.). Driven primarily by power rating rather than energy storage capacity and volume of electrolyte |
| Auxiliary power consumption (standby) | MW | 6.8 | 6.8 | Figure provided is indicative mid-range figure. Significant range depending on supplier, technology maturity, required standby mode and site conditions. Indicative range of 1 to 5% of power rating, with the upper end reflecting systems held in active fast response standby mode. |
| Auxiliary load | % | 6.0 | 6.0 | Based on operating power consumption |
| Auxiliary load | % | 3.4 | 3.4 | Based on standby power consumption |
| Power Capacity (Net) | MW | 188 | 188 | |
| Seasonal Rating – Summer (Net) | MW | 188 | 188 | Dependent on inverter supplier. Potentially no de-rate, or up to approx. 4% at 35°C. |
| Seasonal Rating – Not Summer (Net) | MW | 188 | 188 | |

| Item | Unit | 24 hours | 48 hours | Comment |
|---|---|---|---|---|
| **Annual Performance** | | | | |
| Equivalent forced outage rate | % | 1.5 - 3% | | Dependent on level of long-term service agreement, retention of strategic spares etc. |
| Annual number of cycles | | 365 - 730 | | Flow batteries have high cycling potential, with assumption presented based on 1 – 2 cycles per day without appreciable degradation impact. Actual cycling dependent on use case and economically rational cycling opportunities. |
| Annual degradation over design life | % | 0.5 | | Indicative average annual degradation figure. |

**Table 9-5 Vanadium-redox BESS technical parameters and project timeline**

| Item | Unit | 24 hours | 48 hours | Comment |
|---|---|---|---|---|
| **Technical parameters** | | | | |
| Ramp Up Rate | MW/ min | 10,000+ | | 0 to 100% rated MW capacity within less than a second if held in active standby mode with pumps running (150 ms typical, dependent inverter response times) |
| Ramp Down Rate | MW/ min | 10,000+ | | As above. |
| Round trip efficiency | % | 62 | 62 | Indicative round trip efficiency, at the point of connection (including auxiliaries), for a full cycle of charge and discharge. Significant range dependent battery product. Variability between suppliers expected. |
| ▪ Charge efficiency | % | 81 | 81 | Assumed to be half of the round-trip efficiency. |
| ▪ Discharge efficiency | % | 81 | 81 | Assumed to be half of the round-trip efficiency. |
| Allowable maximum state of charge (SOC) | % | 100 | | Vanadium-redox batteries can be fully discharged. |
| Allowable minimum state of charge (SOC) | % | 0 | | As above. |
| Maximum number of cycles | | 9,000-18,000 | | Represents 1-2 cycles over a 25-year period; dependent on battery product. |
| Depth of Discharge | % | 100 | | Vanadium-redox batteries can be fully discharged. |

| Item | Unit | 24 hours | 48 hours | Comment |
|---|---|---|---|---|
| **Project timeline** | | | | |
| Time for development | Years | 2 | | |
| Total EPC Programme | Years | 2.5 | 3 | For NTP to COD. High level estimate only (no VRFB projects of this scale have as yet been proposed). Assumes some parallel equipment supply and construction activities. |
| ▪ Total lead time | Years | 1.5 | 2 | High level estimate only (no VRFB projects of this scale have as yet been proposed) |
| ▪ Construction time | Years | 1.5 | 2 | High level estimate only (no VRFB projects of this scale have as yet been proposed) |
| Economic Life (Design Life) | Years | 25 | | 20 to 25-year warranted lifetime is reasonable for vanadium-redox flow batteries, with the battery stack typically needing replacement at approximately 10 years. The electrolyte may be useable in future projects or sold on the wholesale market at end of project life. |
| Technical Life (Operational Life) | Years | 25 | | Technical life may potentially be extended beyond economic life with appropriate maintenance and/or equipment refurbishment. |

### 9.3.3 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 9-6 Cost estimates**

| Item | Unit | 24 hours | 48 hours | Comment |
|---|---|---|---|---|
| **CAPEX – EPC cost for 200 MW BESS (with dedicated grid connection)** | | | | |
| Relative cost – Power component | $ / kW | 2,936 | 2,936 | Indicative cost for power related components and other costs independent of storage duration |
| Relative cost – Energy component | $ / kWh | 290 | 290 | Indicative cost for energy related components |
| Total EPC cost | $M | 1,981 | 3,375 | Indicative total cost |
| ▪ Equipment cost | $M | 1,624 | 2,767 | As above. |
| ▪ Installation cost | $M | 357 | 608 | As above. |
| **CAPEX – EPC cost for 200 MW BESS (co-located with renewable installation)** | | | | |
| Relative cost – Power component | $ / kW | 2,876 | 2,876 | Indicative cost for power related components and other costs independent of storage duration |

| Item | Unit | 24 hours | 48 hours | Comment |
|---|---|---|---|---|
| Relative cost – Energy component | $ / kWh | 290 | 290 | Indicative cost for energy related components |
| Total EPC cost | $M | 1,969 | 3,363 | Based on an estimated $10,000,000 savings in transformer and associated grid voltage equipment (ie cost worn by co-located project) |
| ▪ Equipment cost | $M | 1,615 | 2,757 | As above. |
| ▪ Installation cost | $M | 354 | 6706 | As above. |
| **Other costs** | | | | |
| Cost of land and development | $ | 15,000,000 | | |
| **OPEX – Annual** | | | | |
| Fixed O&M Cost | $/MW (Net) | 51,000 | 79,000 | Indicative, provided on $/MW basis for input into GenCost template only. |
| Variable O&M Cost | $/MWh (Net) | - | - | BESS long term service agreements not typically based on fixed / variable. |
| Total annual O&M Cost | $k | 10,200 | 15,800 | Highly variable between OEMs.<br>Indicative average cost over the design life<br>Does not include mid-life stack replacement |

## 9.4 Residential battery storage

### 9.4.1 Overview

Residential Battery Energy Storage Systems (RBESS) form a rapidly growing market segment in Australia. There are a range of system architectures available, most of which use lithium-ion (Li-ion) technologies. The RBESS industry is relatively immature, as manifested by product quality problems and volatility among market players. An example of this is the recent re-call of RBESS batteries from LGChem. However, this is expected to normalise as the industry becomes more established over the coming years.

Batteries are used by consumers for a range of services, most notably improved utilisation of rooftop PV energy yield, as a back-up reliability measure for grid outages and off-grid power supplies. Price reductions in Li-ion batteries over the medium to long term are expected to drive increased uptake of RBESS.

As residential battery systems become more common in Australia, there will be greater potential to aggregate energy storage to perform services similar to large-scale BESS. Such Virtual Power Plants (VPPs) are already emerging. In September 2021, the Australian Energy Market Commission (AEMC) announced a National Electricity Market (NEM) rule change that will enable aggregated small batteries to participate in the ancillary services market from mid-2024. VPPs may challenge grid-scale batteries in some markets but are expected to have differing economics and technical capability when compared to larger systems. The RBESS economics is based on many small units being produced and sold whereas the grid scale BESS rely on economies of scale. Also, the technical capability of the RBESS generally follow a “set and forget” (static) mode performance whilst the grid scale BESS has a dynamic control system.

### 9.4.2 Typical options

As with large-scale BESS, residential battery storage is dominated by Lithium-ion technologies, with Lithium Iron Phosphate (LFP) being the most common battery chemistry. This is followed by Lithium Nickel Manganese Cobalt Oxide (NMC). There are also single instances of Lithium Nickel Cobalt Aluminium (NCA) and Lithium Titanate battery products on the market.

Energy consumers use home batteries to provide several key services including storage of excess solar energy generation, arbitrage/load shifting, contingency FCAS (with VPP aggregated systems), back-up during grid power outages and off-grid operation. The back-up system may include all home circuits or selected essential circuits only, with the former entailing a larger storage capacity to support higher energy loads. RBESS systems also have potential to provide distribution network support services such as load flow and voltage constraint management, particularly if aggregated through a VPP.

RBESS may be coupled with the DC circuit associated with a rooftop solar installation or the AC circuits of a household. Depending on how the system is electrically arranged, integrated home battery systems may consist of one or more battery cells connected in series, charge controllers and/or 'two-way' inverters (which also rectify AC current to DC, when coupled with the AC circuit). They may also include smart system controllers to enable various services such as arbitrage and power back-up, often with an interactive user interface. Many RBESS products are designed to be paired directly with a compatible solar inverter to provide more sophisticated functionality.

RBESS power capacities of 2-10 kW are readily available, with most products falling in the range of 3-6 kW[95]. The systems often integrate up to 2 hours of storage, but this also varies considerably, with storage durations of 1.0-2.5 hours being common. There are a large range of products offering different system components, services and levels of quality, as reflected in the broad price range. The total number of home battery products on the market has increased significantly relative to 2022 and the majority of these are batteries only or are 'all-in-one' (including both a battery and solar inverter), with a smaller number of products offering batteries equipped with a battery inverter only.

As with the growing market penetration of electric vehicles (EV), it is expected that RBESS will be used as a means to provide generation shift. The RBESS will be charged at high VRE (roof top solar) generation and the energy stored until required to charge the EV typically over-night. Hence running the EV on self-generated "free energy".

### 9.4.3 Recent trends

The Clean Energy Council estimates that 50,000 household batteries with a combined capacity of 347 MWh were installed in Australia in 2021, which is a 144% increase on the 34,731 batteries installed in the previous year[96]. This aligns with an analysis conducted by SunWiz which estimated that 47,100 RBESS systems were installed in 2022 with 57,000 RBESS systems installed in 2023, giving a total RBESS capacity in Australia of 2,770 MWh[97]. There was also an increase in the number of batteries being installed alongside new solar installations (1 out of 7 solar installations in 2023 compared to 1 out of 12 in 2021). There is an active home battery state rebate scheme in the Northern Territory, with an interest-free loan scheme for home batteries also available in Victoria. The CEC analysis noted that the length of household battery warranties have increased; however, Aurecon notes that 10 years still seems to be the standard offering, with some vendors warranting the systems to 15-20 years.

Despite the growth of the RBESS market, it is still a relatively immature sector. An independent testing facility performing accelerated testing on battery products has highlighted the large variation in product quality [98]. The study, completed in 2022, found that faults, failures and underperformance were common across many products, generally attributed to poor product development and/or poor integration with external system components. Possibly in response to these problems, there is a trend in the industry towards fully integrated battery systems (ie those containing compatible batteries, inverters and other components from the same manufacturer) to avoid interfacing issues. Another trend that was brought to light in the study is a

[95] https://www.solarquotes.com.au/battery-storage/comparison-table/
[96] Clean Energy Australia Report 2023, Clean Energy Council
[97] "SunWiz reports residential battery installs at record high, D. Carroll, pv magazine, 30 March 2023
[98] Public Report 12 (Final Report) – Lithium-ion Battery Testing, ITP Renewables, March 2022

shift towards high-voltage systems which are more efficient and easier/cheaper to install due to the smaller required cable sizes. The study has also found a large variation in energy capacity degradation rates across the products tested, while system efficiency was less variable.

The average cost of a system is estimated by Aurecon to have dropped by approximately 10% relative to 2022, which is likely to be primarily driven by greater competition in the industry but also by recent reductions in lithium carbonate commodity prices.

### 9.4.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM, given the above discussion on typical options and current trends.

**Table 9-7 RBESS configuration and performance**

| Item | Unit | 2 hours | Comment |
|---|---|---|---|
| **Configuration** | | | |
| Technology | | Li-ion | |
| **Performance** | | | |
| Power Capacity (gross) | kW | 5 | |
| Energy Capacity | kWh | 10 | |
| Auxiliary power consumption (operating) | W | 50 | Indicative figures (variable dependent on system components and services performed). |
| Auxiliary load | % | 1.0 | Based on operating power consumption |
| Power Capacity (Net) | kW | 4.95 | |
| Seasonal Rating – Summer (Net) | kW | 4.95 | Dependent on inverter supplier. Potentially no de-rate or up to approximately 4% at 35°C. |
| Seasonal Rating – Not Summer (Net) | kW | 4.95 | |
| **Annual Performance** | | | |
| Equivalent forced outage rate | % | 4.3 | This will be highly variable depending on the quality and serving arrangements for a particular RBESS system, noting that product faults are common. A range of 1 day to 1 month may be reasonable, giving an outage rate of 0.3% to 8.3%. The midpoint of this range has been considered but this should be reviewed as further data becomes available. |
| Annual number of cycles | | 365 | Typical default assumption is one cycle per day, however this is highly dependent on functional requirements and operating strategy. |
| Annual degradation over design life | % | 1.8 | Indicative average annual degradation figure provided for 10-year RBESS, assuming LFP battery chemistry. Significant range dependent battery supplier, or approximately 79 – 85% energy retention after 10 years (based on one cycle per day). Degradation dependent on factors such as energy throughput, charge / discharge rates, depth of discharge, and resting state of charge. |

**Table 9-8 RBESS technical parameters and project timeline**

| Item | Unit | 2 hours | Comment |
|---|---|---|---|
| **Technical Parameters** | | | |
| Ramp Up Rate | kW/min | 10,000+ | 0 to 100% rated kW capacity within approximately 250 ms typical for frequency response, within approximately 1s typical for response to external commands. |
| Ramp Down Rate | kW/min | 10,000+ | As above |
| Round-trip efficiency | % | 90 | Energy retention, at the point of connection (including auxiliaries), for a full cycle of charge and discharge. Range of 77-95% lifetime round-trip efficiency observed in RBESS battery testing study[99]. |
| Charge efficiency | % | 95 | Assumed to be half of the round-trip efficiency. |
| Discharge efficiency | % | 95 | Assumed to be half of the round-trip efficiency. |
| Allowable maximum state of charge (SOC) | % | 100 | Performance and costs presented relate to the useable RBESS energy storage capacity / state of charge (SOC), with operation permissible throughout this full range. |
| Allowable minimum state of charge (SOC) | % | 0 | As above. |
| Maximum number of cycles | | 3,653 | Typical warranty conditions based on one cycle per day for 10 years for a RBESS. |
| Depth of Discharge | % | 100 | 100% in terms of typically defined 'useable state of charge. |
| **Project Timeline** | | | |
| Time for development ordering, installation | Days | 90 | Pragmatic assumption. |
| Economic Life (Design Life) | Years | 10 | 10 years is a typical warranted period for RBESS. |
| Technical Life (Operational Life) | Years | 10 | Given the volatility of the RBESS market and observed problems with product quality, it is reasonable to assume that many RBESS products will not reach or operate beyond their warranted period. |

## 9.4.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 9-9 Cost estimates**

| Item | Unit | 2 hours | Comment |
|---|---|---|---|
| **Installation costs for 5 kW RBESS (AC-coupled, not including new PV inverter)** | | | |
| Relative cost – Power component | $ / kW | - | Correlation based on power and energy storage ratings do not follow readily identifiable patterns due to the wide range of products |
| Relative cost – Energy component | $ / kWh | - | As above |
| Total cost | $ | 13,500 | |

[99] Public Report 12 (Final Report) – Lithium-ion Battery Testing, ITP Renewables, March 2022

| Item | Unit | 2 hours | Comment |
| --- | --- | --- | --- |
| Equipment cost | $ | 10,800 | As above. |
| Installation cost | $ | 2,700 | As above. |
| **Other Costs** | | | |
| Operational costs | $ | - | Maintenance costs due to faults or component failures should be covered under the product warranty. |
| Economic Life (Design Life) | Years | 10 | 10 years is a typical warranted period for RBESS. |
| Technical Life (Operational Life) | Years | 10 | Given the volatility of the RBESS market and observed problems with product quality, it is reasonable to assume that many RBESS products will not reach or operate beyond their warranted period. |

## 9.5 Large-scale iron air battery storage

### 9.5.1 Overview

Iron-air batteries are an emerging long duration energy storage technology with a significantly higher energy density compared with most other battery options. It offers deep storage complementary to large-scale lithium-ion BESS. The mechanism of energy storage in an iron-air battery is termed "reversible rusting". This process converts rust (iron oxide) to iron when an electrical input is applied (charge mode). The resulting iron can be converted back to rust when required and this will generate an electrical output (discharge mode).

A similar process can be performed with other metals, however, iron is particularly chosen for grid-scale storage applications due to its high abundance, low cost, rechargeability, relatively longer life cycle and non-toxic nature.

Figure 9-2 depicts the electrolytic process of an iron-air battery.

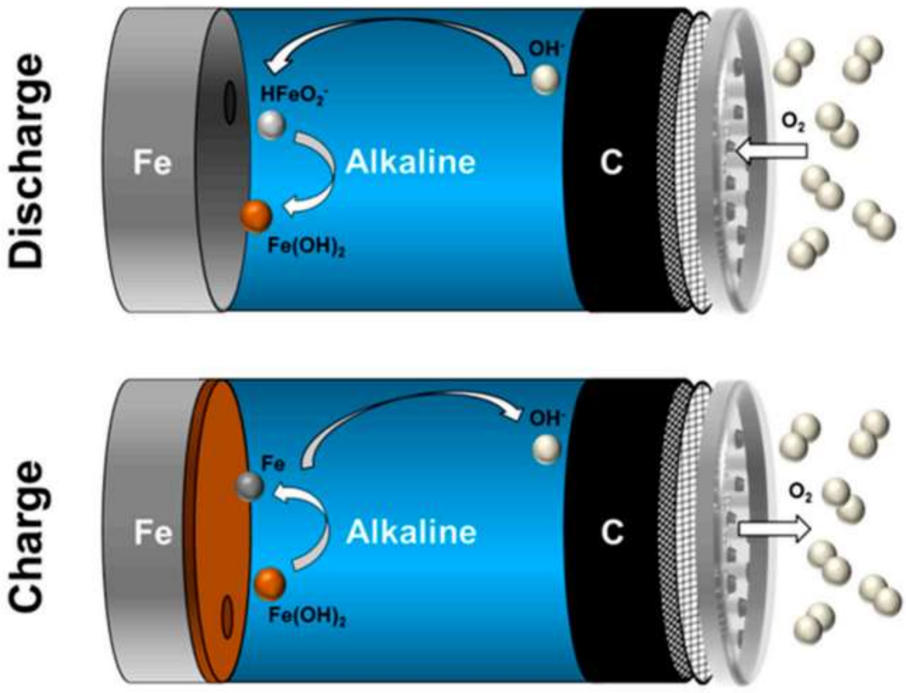


Figure 9-2 Conceptual diagram of a metal-air battery cell

Iron-air batteries offer a number of advantages over lithium-ion BESS, such as:

Long duration storage capability (as high as 100 hours)

Safety, as there is no risk of overheating or thermal runaway

Lower cost due to its reliance on inexpensive materials.

However, there appears to be some challenges which researchers are trying to overcome, such as:

Lower round trip efficiency (50-60% vs 90%+ for Li-ion BESS)

Larger and heavier creating challenges when space becomes limited

Slower response times (may not be suitable for applications requiring rapid energy discharge and charge cycles)

It should however be noted that the technology is still in its infancy. Table 9-10 shows a comparison of their technical parameters with other relevant battery types.

**Table 9-10 Comparison of technical parameters between battery types: iron-air, iron-flow and Li-ion**

| Parameter | Iron-Air | Iron-flow | Li-ion (LFP) |
|---|---|---|---|
| Design life | Expected to be longer than other BESS technologies | 25 years | 15-20 years |
| No. cycles | 3,500 [100] | 20,000 | 5,500-7,300 |
| Battery RTE efficiency | 50-60% | 70-75% [101] | 90-95% [101] |
| Approx. volumetric energy density | 1,000+ Wh/L [102] | 38 Wh/L [103] | 325 Wh/L [103] |
| Typical cell voltage | 1.28 V [100] | 1.21 V | 3.7 V |
| Operating temperature | Ambient | -10°C to 50°C [104] | -10°C to 50°C [104] |

### 9.5.2 Deployed capacity

Form Energy; a US-based company, is leading the development and deployment of iron-air batteries, currently engaged in multiple projects across different stages. Due to Form Energy being the global pioneer in this technology, the total number of projects worldwide is limited to the projects in Form Energy's pipeline.

**Figure 9-3 Planned iron air battery projects**

| Location | Capacity | Storage Duration (h) | Date Online | Expected Completion | Battery supplier |
|---|---|---|---|---|---|
| Maine, USA [105] | 85 MW | 100 | 2028 | Renewables | Form Energy |
| Georgia, USA [106] | 15 MW | 100 | 2026 | Renewables | Form Energy |
| Minnesota, USA [107] | 10 MW | 100 | 2025 | Renewables | Form Energy |

Aurecon does not have information regarding costs of above privately developed projects and as such no cost information is provided in this report.

[100] Olabi, A.G.; Sayed, E.T.; Wilberforce, T.; Jamal, A.; Alami, A.H.; Elsaid, K.; Rahman, S.M.A; Shah, S.K.; Abdelkareem, M.A. (2021) Metal-Air Batteries—A Review, Energies, 14, 7373. https://doi.org/10.3390/en14217373

[101] 'Iron flow battery tech shows promise for mid-duration energy storage' John Fitzgerald Weaver, PV Magazine [Online] October 8, 2021.

[102] Experimental energy density given by Olabi et al. (2021) is 453 $Wh/kg_{Fe}$, which correlates to roughly 302 Wh/kg cell density (1.5 ratio), which correlates to 1,026 Wh/L across the cell (3.4kg/L density). Theoretical maximum is 2,598Wh/L across the cell.

[103] 'Iron-chromium redox flow battery with high energy density' Emiliano Belllini, PV Magazine [Online], July 11, 2023

[104] 'Iron Flow Battery Technology and Its Role in Energy Storage', WattCo [Online], April 18, 2022

[105] Form Energy set to build world's biggest battery in… | Canary Media

[106] Georgia Power, Form Energy to deploy 100-hour iron-air battery system (power-eng.com)

[107] Minnesota PUC approves multi-day energy storage project (renewableenergyworld.com)

### 9.5.3 Commodity risks

The essential materials required for iron-air battery production include iron and a water-based electrolyte (commonly potassium hydroxide (KOH)), both of which are cheap and abundant.

Iron is one of earth's most abundant materials, making up approximately 5% of the earth's crust. The natural abundance of iron in the earth's surface means that it has a relatively low supply risk. The Royal Society of Chemistry (RSC) ranks the relative supply risk of iron at 5.2/10, compared to 6.7/10 for lithium[108].

The relative supply risk of potassium chloride (KCl), which is required to produce KOH, is ranked by the U.S. Environmental Protection agency as "low", with no history of supply disruptions between 2000 and 2022.[109]

### 9.5.4 Development trends

Iron-air batteries can be considered a potential solution to the problem of long-term duration energy storage posed by the shortfalls in Li-ion BESS. The central advantages of iron-air batteries over Li-ion technologies are as follows:

the lower cost of materials

safety

higher energy density,

environmentally friendly

recyclable and

smaller environmental impact compared to other battery chemistries.

However, their current challenges include a lower RTE efficiency, and slower response times.

Ensuring long-term stability and efficiency is critical for iron-air development. This requires an optimization of electrode structures, surface coatings, and electrolyte compositions to minimize degradation and enhance performance. Researchers are actively pursuing multiple options, opportunities and strategies to address these challenges as follows:[110]

Cathode ($O_2$) catalysts; for enhancing oxygen reduction,

Electrolyte optimization; to improve the stability and conductivity of the electrolyte,

Dendrite (crystal formation between plates) suppression; to enhance safety and cycling stability, and

System integration; considering factors such as scalability, efficiency, and cost-effectiveness

Form Energy is aiming to create iron-air batteries as a complementary longer duration storage option alongside lithium-ion batteries[111] as the short duration storage of lithium-ion batteries is likely to leave gaps in energy supply during renewable droughts and winter as the penetration of variable renewable energy increases.

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[108] Royal Society of Chemistry [Online], https://www.rsc.org/periodic-table/

[109] Potassium Chloride Supply Chain – Executive Summary | U.S. EPA

[110] Ikeuba, A. I., Iwuji, P. C., Nabuk, I. I. E., Obono, O. E., Charlie, D., Etim, A. A., ... & Amajama, J. (2024). Advances on lithium, magnesium, zinc, and iron-air batteries as energy delivery devices—a critical review. *Journal of Solid State Electrochemistry*, 1-27.

[111] Battery Technology | Form Energy

# 10 Compressed Air Storage System

## 10.1 Compressed air storage system

### 10.1.1 Overview

Compressed air energy storage (CAES) can be used for medium to long duration storage (8 to more than 12 hours) to support high penetration of variable renewable energy. CAES compliments battery energy and pumped hydro storage systems and provides grid stability services, such as spinning reserves, voltage support, synchronous inertia etc.

30 to 40% of the energy supplied to the system during operation is lost and not available when the system discharges energy. These losses are mainly due to the isentropic efficiency losses in the compressor and turbine equipment and referred to as the round-trip efficiency losses.

### 10.1.2 Typical options

Earlier CAES plants typically store compressed air in a cavern and use it in an expanding turbine when energy is needed. Such systems do not recover heat energy generated during the compression process resulting in low round trip efficiency.

Traditional CAES design was improved with the addition of combustion of fuel to heat stored air prior to expansion in the turbine. This is known as Diabatic- CAES (D- CAES) which augments the basic CAES system by introducing heat energy to the compressed air. However, as no attempt is made to recover or re-use the heat energy during compression, their environmental performance was poor.

Recent advancement is known as Adiabatic- CAES (A-CAES) where heat of compression is stored in a thermal energy storage (TES) system and used to preheat air prior to expansion in the turbine. A-CAES has higher round trip efficiency and the absence of fossil fuel combustion makes it more environment friendly.

A-CAES system also uses a surface water reservoir and a shaft connecting the reservoir and the storage cavern to create a pressure balance enabling constant air pressure in the Cavern. The level of water in the reservoir rises during energy storage and the level of water falls during the energy discharge cycle. It also uses insulated tanks to hold hot and cold water in the TES system. Typically, the system requires systems and equipment as listed below.

a. Energy conversion system (motor, compressor, turbine and generator, electrical switchroom)
b. Air storage system (Cavern, water surface reservoir and shaft)
c. Thermal energy storage (heat exchangers to transfer heat from air to water, insulated hot water tanks, heat exchangers to transfer heat from hot water to air and cold water storage tanks).

A typical A-CAES system is depicted in the figure below. This report considers an A-CAES system with the configuration shown below.

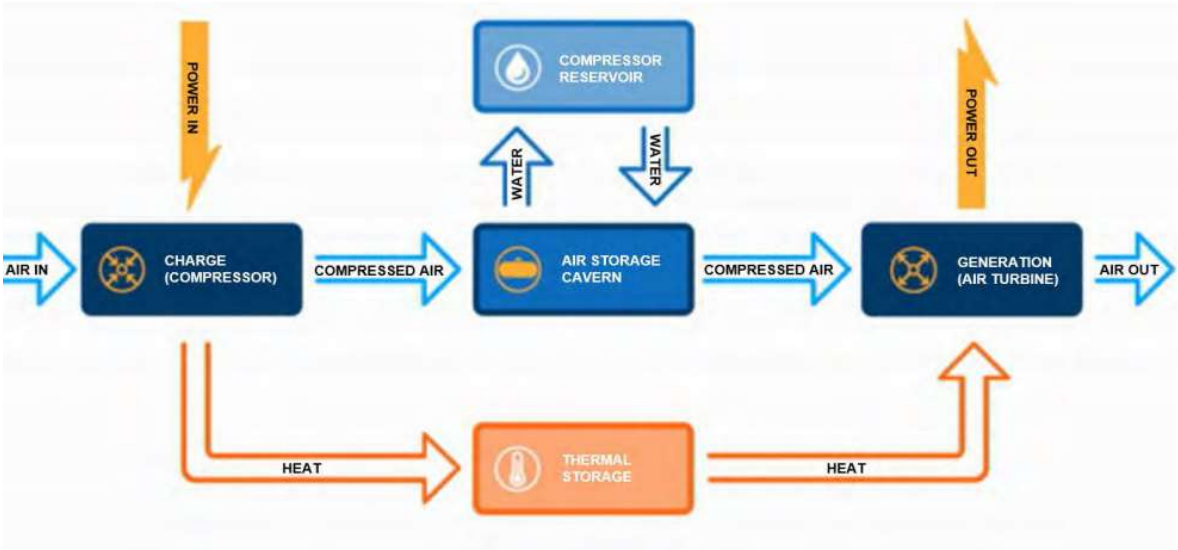


**Figure 10-1 Hydrostor A-CAES technology**

Reference: TWD Report – Independent Engineering Assessment of Scalable 100 MW A-CAES Design, 2021

### 10.1.3 Recent trends

D-CAES was first used in two earlier CAES projects, one in Huntorf, Germany in 1978 (290 MW with 4 hours of storage) and the other in McIntosh, USA in 1991 (110 Mw with 26 hours of storage). Both plants were installed for load shifting, peak shaving and voltage regulation utilising purpose-built salt caverns.

Hydrostor is a Canadian technology development company currently developing A-CAES projects in many countries. The company has undertaken the following development activities in Canada.

- Toronto Island Energy Storage Facility

This research and development and testing facility was commissioned in 2015 to demonstrate the technology and its components.

- Goderich A-CAES Facility in Ontario, Canada.

This facility comprises 1.75 MW of peak output, 2.20 MW of charge rating and 7 MWh of storage and has been operating commercially since 2019. The plant is being used by Ontario's independent Electricity system operator (IESO) for peaking capacity, ancillary services and full participation in the merchant energy market to support grid reliability.

Outside of Australia Hydrostor has the following project currently at various stages of project development.

- Willow Rock Energy Storage Centre in Kern County, California (500 MW A- CAES system for 8 hours of storage)

There is no operating compressed air storage project in Australia. Hydrostor is developing the Silver City Energy Storage Project in NSW utilising A – CAES technology. The NSW Government has provided funding for the feasibility of this 200 MW (2 x 100 MW trains) and 1600 MWh storage plant to be installed at Broken Hill to solve grid congestion issues being experienced by existing renewable energy projects in the region. The project will repurpose existing mining infrastructure. Transgrid has selected the Silvercity A- CAES project as the preferred technology option for grid stability in the region.

According to The Australian Financial Review (AFR), The project is expected to cost between $600 million and $1 billion and the financial close is expected by the end of 2024 or early 2025. AFR also reports that the project has attracted interest from potential equity partners and financiers. The current status of the Silver City Energy Storage Project is as below.

- The project has obtained an ARENA grant of $45 million (subject to the project reaching financial close by the end of 2023)

- The Project Submission and Amendment Report has been accepted by the NSW Department of Planning, Housing and Infrastructure
- In December 2023, the Silver City Project was awarded both a Network Service Agreement with Transgrid, and a Long-Term Energy Service Agreement (LTESA) from Australian Energy Market Operator (AEMO) Services under the New South Wales government's electricity infrastructure roadmap
- The front-end engineering and design (FEED) started in 2022, being undertaken by McDermott
- Completed a binding agreement with mining firm Perilya to progress the project. The agreement includes access to property transactions and existing Potosi mine infrastructure, the provision of construction support services and supports the continued and longer-term operation of the Potosi Mine during and after the project is being built.

### 10.1.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a potentially plausible project subject to feasibility for installation in the NEM and in a remote area location (off-grid), given the above discussion on typical options and current trends. The NEM connected project is associated with a cavern storage, whereas the off-grid project considers fabricated storage vessels.

It should be noted that for storage in vessels, the design should consider aspects of pressure balance to maintain air pressure in the vessel. This aspect has not been considered and as such costs may vary in actual design. The available useable storage volume has been considered at a certain pressure during discharge cycle.

**Table 10-1 A-CAES configuration and performance**

| Item | Unit | 24 hours storage | 12 hours storage | Comment |
|---|---|---|---|---|
| **Configuration** | | | | |
| Technology | | A-CAES (with cavern storage) | A-CAES (with vessel storage) | |
| **Performance** | | | | |
| Power Capacity (gross) | MW | 200 | 50 | |
| Energy Capacity | MWh | 4800 | 600 | |
| Auxiliary power consumption (operating) | kW | Negligible | Negligible | Included in Round Trip Efficiency[112] |
| Auxiliary power consumption (standby) | kW | Negligible | Negligible | Included in Round Trip Efficiency[112] |
| Power Capacity (Net) | MW | 200 | 50 | |
| Seasonal Rating – Summer (Net) | MW | 200 | 50 | |
| Seasonal Rating – Not Summer (Net) | MW | 200 | 50 | |
| Cavern/vessel air storage volume | $m^3$ | 640,000 - 700,000[113] | 80,000 – 90,000 | Scaled up for cavern storage |
| Cavern/vessel air pressure | Bar | 60 | | |
| Cavern/vessel air temperature | $^0C$ | 40 | 40 | |
| Surface reservoir volume | $m^3$ | 720,000[112] | N/A | Scaled up for cavern storage |
| Thermal storage volume | $m^3$ | 38,400[113] | 4,800 | Scaled up for cavern storage |

[112] Hydrostor: Advanced Compressed Air Energy Storage: Technology & Project Delivery Overview 2020
[113] Feasibility study of adiabatic compressed air energy storage in porous reservoirs, Jason et. Al, CSIRO Publishing, the APPEA Journal, 2022

| Item | Unit | 24 hours storage | 12 hours storage | Comment |
|---|---|---|---|---|
| Thermal storage temperature/Pressure | $^0$C/Bar | 210/20[113] | 210/20 | |
| **Annual Performance** | | | | |
| Average Planned Maintenance | Days / yr. | 3 | 3 | Included in EFOR. |
| Equivalent forced outage rate | % | 2 | 2 | Dependent on level of long-term service agreement, retention of strategic spares etc. |
| Annual number of cycles | | No limit | No limit | |
| Annual degradation over design life | % | Negligible[112] | Negligible | |

Table 10-2 Technical parameters and project timeline

| Item | Unit | 12 hours storage | 12 hours storage | Comment |
|---|---|---|---|---|
| **Technical parameters** | | | | |
| Technology | | A-CAES (with cavern storage) | A-CAES (with vessel storage) | |
| Ramp Up Rate | %/min | 25[112] | 25 | |
| Ramp Down Rate | %/min | 25 | 25 | As above. |
| Round trip efficiency | % | 60-65 | 60-65 | Round trip efficiency, at the point of connection (including auxiliaries), for a full cycle of charge and discharge |
| Response time (time from signal to full charge and time from signal to initial discharge) | min | 5[112] | 5 | |
| Synchronous condenser mode<br>(Auxiliary power requirement) | % | 0.5 – 2% of power rating | 0.5 – 2% of power rating | Auxiliary power draw to operate the system as a synchronous condenser for continuous voltage support[112] |
| Allowable maximum state of power charge | % | 100 | 100 | A-CAES system with pressure balance using hydrostatic head assumed |
| Allowable minimum state of power charge | % | 0 | 0 | As above. |
| Maximum number of cycles | | 20,000[112] | 20,000 | |
| **Project timeline** | | | | |
| Time for development | Years | 2-3 | 2-3 | Includes re-feasibility, design, approvals etc |
| First Year Assumed Commercially Viable for construction | Year | 2024 | 2024 | |
| Total EPC Programme | Years | 3 | 3 | For NTP to COD. |
| ▪ Total lead time | Years | 1 | 1 | Time from NTP to compressor, turbine on site |
| ▪ Construction time | Years | 2 | 2 | Time from compressor/turbine on site to COD |
| Economic Life (Design Life) | Years | 30 years | 30 years | Same as any rotating plant |

| Item | Unit | 12 hours storage | 12 hours storage | Comment |
|---|---|---|---|---|
| Technical Life (Operational Life) | Years | 30-50 years | 30-50 years | Same as any rotating plant |

### 10.1.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

**Table 10-3 Cost estimates**

| Item | Unit | A-CAES with cavern storage for 24 hours | A-CAES with vessel storage for 12 hours | Comment |
|---|---|---|---|---|
| **CAPEX – EPC cost** | | | | |
| Relative cost - Power component | $ / kW | 1935 | 1935 | Indicative cost for power related components. Relative cost does not include land and development costs. |
| Relative cost - Energy component | $ / kWh | 228 | 740 | Indicative cost for sub-surface cost |
| Total EPC cost | $M | 1480 | 541 | Based on Aurecon internal database of similarly sized projects and scaled for additional energy storage capacity. |
| ▪ Equipment cost | $M | 1037 | 378.8 | As above (70% of EPC Cost). |
| ▪ Installation cost | $M | 444 | 162.3 | As above (30% of EPC cost). |
| **Other costs** | | | | |
| Cost of land and development | $ | 37,023,000 | 13,528,000 | 2.5% of EPC cost on lease basis |
| **OPEX – Annual** | | | | |
| Fixed O&M Cost | $/MW /year | 36,570 | 36,570 | Provided on $/MW/year basis for input into GenCost template only. |
| Variable O&M Cost | $/MWh | 4.45 | 4.45 | Assumed one cycle a day |
| Total annual O&M Cost | $M | 15.1 | 2.8 | Annual average cost over the design life |

# 11 Location Factors

## 11.1 General

Costs for various technologies provided in this report are based on the assumption that projects (except offshore wind projects) are located in the metropolitan areas in the NEM region. For projects that are not located in the metropolitan areas, a location cost factor needs to be applied for equipment, installation, fuel connection, land and development and operation and maintenance. Assumptions regarding the development of these cost factors are provided below. Location factors as discussed in this section of the report apply for renewable energy projects only, however they do not apply for offshore wind projects due to the very nature of their locations.

For the development of location factor in Table 11-1, we have extracted data from Rawlinson 2024114.

The location factor is an overall factor that includes equipment cost factor and installation cost factor. The location cost factor has been assumed to be unity “1” in metropolitan capital cities in the NEM region. The location cost factor varies when moving away from the capital city. It is assumed that the location cost factor includes equipment cost factor and location cost factor in the proportion of 60% and 40% respectively.

The location factors derived are simplified and are a guide only and as such used with caution. Actual location factors should be assessed on a project specific basis and its delivery approach.

## 11.2 Equipment cost factor

Equipment cost factor is understood to be related to transport of material, plant, and equipment for construction. This factor is assumed to vary between 1.01 and 1.15, depending upon the distance from capital cities. We have applied this factor accordingly based on the approximate distance from the capital city. We did not consider local ports as the port capability needs to be investigated for transporting long wind turbine blades. This is consistent with Rawlinson 2024[114] approach for calculating location factors.

## 11.3 Installation cost factor

Regional factors for installation cost include material, labour, and mobilisation and demobilisation of resources from metropolitan area to regional sites. The installation cost factors have been calculated from the location factors by applying a proportion of 60% equipment cost (the equipment cost was used for transport of construction materials such as steel and concrete) and 40% installation cost on a weighted basis. The assumption of this proportion of equipment cost and installation cost is typical for construction of renewable energy projects.

## 11.4 Fuel connection cost factor

As these location factors are applicable for renewable energy projects, fuel connection cost factor has not been developed and reported.

## 11.5 Cost of land and development

Land and development costs have been treated for each technology areas separately and costs are provided accordingly. Land costs are not expected to vary significantly between regional areas. Furthermore, land costs are a small fraction of overall project costs. For the purpose of developing location factors, we have reported this as 1.00 for all regional locations.

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[114] Rawlinsons Quantity Surveyors and Construction Cost Consultants Australia (2024), Rawlinsons Australian Construction Handbook (42nd ed.), Rawlinsons Publishing

## 11.6 Operation and maintenance costs

Similar to fuel connection, scope of operation and maintenance (O&M) includes procurement of material from a warehouse in metropolitan area, delivery to site and installation based on maintenance scope. Hence, the O&M regional factor is assumed to be a combination of equipment and installation location factors. We have calculated these operation and maintenance cost factors by assuming a proportion of 50% equipment cost factor (this equipment cost factor is for transporting of plant equipment, such as spare parts) and 50% installation cost factor on weighted basis.

## 11.7 Aurecon estimate of location factors in the NEM region

Based on above approaches, we have developed the below table which provides location factors as applicable in the NEM region for Renewable Energy Zones (REZs) in various states.

**Table 11-1 Cost location factors**

| State | REZ Code | Region | Site/ City | Location cost factor | Equip-ment cost factor | Fuel connection cost factor | Land & develop-ment cost factor | Install-ation cost factor | O&M cost factor |
|---|---|---|---|---|---|---|---|---|---|
| QLD | Q1 | Far North Qld | Cooktown | 1.35 | 1.15 | Not applicable | 1.00 | 1.65 | 1.50 |
| QLD | | | Port Douglas | 1.12 | 1.14 | Not applicable | 1.00 | 1.10 | 1.11 |
| QLD | | | Cairns | 1.09 | 1.13 | Not applicable | 1.00 | 1.03 | 1.06 |
| QLD | | | Innisfail | 1.17 | 1.12 | Not applicable | 1.00 | 1.25 | 1.21 |
| QLD | Q2 | North Qld Clean Energy Hub | Forsayth | 1.75 | 1.14 | Not applicable | 1.00 | 2.67[1] | 2.21 |
| QLD | Q3 | Northern Qld | Ingham | 1.18 | 1.11 | Not applicable | 1.00 | 1.28 | 1.23 |
| QLD | | | Townsville | 1.15 | 1.11 | Not applicable | 1.00 | 1.22 | 1.18 |
| QLD | Q4 | Isaac | Bowen | 1.18 | 1.09 | Not applicable | 1.00 | 1.32 | 1.25 |
| QLD | | | Mackay | 1.17 | 1.08 | Not applicable | 1.00 | 1.31 | 1.24 |
| QLD | | | Moranbah | 1.2 | 1.08 | Not applicable | 1.00 | 1.38 | 1.29 |
| QLD | Q5 | Barcaldine | Longreach | 1.35 | 1.09 | Not applicable | 1.00 | 1.74[1] | 1.55 |
| QLD | Q6 | Fitzroy | Rockhampton | 1.17 | 1.05 | Not applicable | 1.00 | 1.36 | 1.26 |
| QLD | Q7 | Wide Bay | Bundaberg | 1.07 | 1.03 | Not applicable | 1.00 | 1.13 | 1.10 |
| QLD | | | Gympie | 1.05 | 1.02 | Not applicable | 1.00 | 1.10 | 1.08 |
| QLD | | | Nambour | 1.02 | 1.01 | Not applicable | 1.00 | 1.04 | 1.03 |
| QLD | | | Maroochydore | 1.02 | 1.01 | Not applicable | 1.00 | 1.04 | 1.03 |
| QLD | Q8 | Darling Downs | Dalby | 1.06 | 1.02 | Not applicable | 1.00 | 1.12 | 1.09 |

| State | REZ Code | Region | Site/ City | Location cost factor | Equip-ment cost factor | Fuel connection cost factor | Land & develop-ment cost factor | Install-ation cost factor | O&M cost factor |
|---|---|---|---|---|---|---|---|---|---|
| QLD | | | Toowoomba | 1.02 | 1.01 | Not applicable | 1.00 | 1.04 | 1.03 |
| QLD | | | Warwick | 1.06 | 1.02 | Not applicable | 1.00 | 1.13 | 1.09 |
| QLD | | | Inglewood | 1.1 | 1.02 | Not applicable | 1.00 | 1.22 | 1.16 |
| QLD | | | Texas | 1.15 | 1.02 | Not applicable | 1.00 | 1.34 | 1.25 |
| QLD | Q9 | Banana | Banana | 1.17 | 1.05 | Not applicable | 1.00 | 1.36 | 1.26 |
| NSW | N1 | North West NSW | Moree | 1.13 | 1.05 | Not applicable | 1.00 | 1.26 | 1.19 |
| NSW | | | Inverell | 1.15 | 1.05 | Not applicable | 1.00 | 1.31 | 1.23 |
| NSW | | | Narrabri | 1.15 | 1.04 | Not applicable | 1.00 | 1.32 | 1.23 |
| NSW | | | Gunnedah | 1.15 | 1.02 | Not applicable | 1.00 | 1.34 | 1.25 |
| NSW | | | Tamworth | 1.05 | 1.03 | Not applicable | 1.00 | 1.08 | 1.07 |
| NSW | | | Walgett | 1.2 | 1.05 | Not applicable | 1.00 | 1.43 | 1.32 |
| NSW | N2 | New England | Armidale | 1.1 | 1.04 | Not applicable | 1.00 | 1.19 | 1.15 |
| NSW | | | Tenterfield | 1.13 | 1.05 | Not applicable | 1.00 | 1.25 | 1.19 |
| NSW | | | Glen Innes | 1.12 | 1.05 | Not applicable | 1.00 | 1.23 | 1.18 |
| NSW | N3 | Central-West Orana | Dubbo | 1.08 | 1.03 | Not applicable | 1.00 | 1.16 | 1.12 |
| NSW | | | Coonamble | 1.2 | 1.04 | Not applicable | 1.00 | 1.44 | 1.32 |
| NSW | | | Coonabarabran | 1.18 | 1.04 | Not applicable | 1.00 | 1.39 | 1.29 |
| NSW | | | Parkes | 1.1 | 1.03 | Not applicable | 1.00 | 1.21 | 1.15 |
| NSW | | | Forbes | 1.1 | 1.03 | Not applicable | 1.00 | 1.21 | 1.15 |
| NSW | | | Condobolin | 1.2 | 1.04 | Not applicable | 1.00 | 1.44 | 1.32 |
| NSW | N4 | Broken Hill | Broken Hill | 1.26 | 1.08 | Not applicable | 1.00 | 1.53 | 1.39 |
| NSW | N5 | South West NSW | Deniliquin | 1.15 | 1.05 | Not applicable | 1.00 | 1.30 | 1.22 |
| NSW | | | Hay | 1.2 | 1.05 | Not applicable | 1.00 | 1.42 | 1.31 |
| NSW | | | Griffith | 1.08 | 1.05 | Not applicable | 1.00 | 1.13 | 1.11 |
| NSW | N6 | Wagga Wagga | Wagga Wagga | 1.03 | 1.04 | Not applicable | 1.00 | 1.02 | 1.02 |

| State | REZ Code | Region | Site/ City | Location cost factor | Equip-ment cost factor | Fuel connection cost factor | Land & develop-ment cost factor | Install-ation cost factor | O&M cost factor |
|---|---|---|---|---|---|---|---|---|---|
| NSW | N7 | Tumut | Tumut | 1.02 | 1.03 | Not applicable | 1.00 | 1.01 | 1.01 |
| NSW | | | Braidwood | 1.05 | 1.02 | Not applicable | 1.00 | 1.09 | 1.07 |
| NSW | N8 | Cooma-Monaro | Bombala | 1.15 | 1.04 | Not applicable | 1.00 | 1.32 | 1.23 |
| NSW | N9 | Hunter-Central Coast | Gosford | 1.02 | 1.01 | Not applicable | 1.00 | 1.04 | 1.03 |
| NSW | | | Newcastle | 1.01 | 1.02 | Not applicable | 1.00 | 1.00 | 1.01 |
| NSW | | | Muswellbrook | 1.09 | 1.02 | Not applicable | 1.00 | 1.19 | 1.14 |
| NSW | | | Singleton | 1.08 | 1.02 | Not applicable | 1.00 | 1.18 | 1.13 |
| NSW | N12 | Illawarra | Wollongong | 1.01 | 1.01 | Not applicable | 1.00 | 1.01 | 1.01 |
| VIC | V1 | Ovens Murray | Mansfield | 1.08 | 1.02 | Not applicable | 1.00 | 1.18 | 1.13 |
| VIC | V2 | Murray River | Kerang | 1.02 | 1.02 | Not applicable | 1.00 | 1.02 | 1.02 |
| VIC | V3 | Western Victoria | Kaniva | 1.06 | 1.03 | Not applicable | 1.00 | 1.11 | 1.08 |
| VIC | V4 | South West Victoria | Casterton | 1.06 | 1.03 | Not applicable | 1.00 | 1.11 | 1.08 |
| VIC | V5 | Gippsland | Morwell | 1 | 1.00 | Not applicable | 1.00 | 1.00 | 1.00 |
| VIC | V6 | Central North Vic | Seymour | 1 | 1.01 | Not applicable | 1.00 | 1.00 | 1.00 |
| SA | S1 | South East SA | Mount Gambier | 1.15 | 1.03 | Not applicable | 1.00 | 1.33 | 1.24 |
| SA | | | Kingston SE | 1.2 | 1.02 | Not applicable | 1.00 | 1.47 | 1.33 |
| SA | | | Bordertown | 1.15 | 1.02 | Not applicable | 1.00 | 1.34 | 1.25 |
| SA | S2 | Riverland | Morgan | 1.15 | 1.02 | Not applicable | 1.00 | 1.35 | 1.25 |
| SA | | | Renmark | 1.15 | 1.02 | Not applicable | 1.00 | 1.34 | 1.25 |
| SA | S3 | Mid-North SA | Clare | 1.1 | 1.01 | Not applicable | 1.00 | 1.24 | 1.17 |
| SA | | | Balaklava | 1.05 | 1.01 | Not applicable | 1.00 | 1.11 | 1.08 |
| SA | S4 | Yorke Peninsula | Maitland | 1.15 | 1.02 | Not applicable | 1.00 | 1.35 | 1.25 |
| SA | | | Yorketown | 1.15 | 1.02 | Not applicable | 1.00 | 1.35 | 1.25 |
| SA | S5 | Northern SA | Whyalla | 1.15 | 1.03 | Not applicable | 1.00 | 1.33 | 1.24 |
| SA | S6 | Leigh Creek | Leigh Creek | 1.25 | 1.04 | Not applicable | 1.00 | 1.57 | 1.41 |

| State | REZ Code | Region | Site/ City | Location cost factor | Equip-ment cost factor | Fuel connection cost factor | Land & develop-ment cost factor | Install-ation cost factor | O&M cost factor |
|---|---|---|---|---|---|---|---|---|---|
| SA | S7 | Roxby Downs | Roxby Downs | 1.3 | 1.05 | Not applicable | 1.00 | 1.68 | 1.49 |
| SA | S8 | Eastern Eyre Peninsula | Port Lincoln | 1.18 | 1.05 | Not applicable | 1.00 | 1.37 | 1.28 |
| SA | S9 | Western Eyre Peninsula | Ceduna | 1.3 | 1.06 | Not applicable | 1.00 | 1.66 | 1.48 |
| TAS | T1 | North East Tasmania | Scottsdale | 1.05 | 1.02 | Not applicable | 1.00 | 1.09 | 1.07 |
| TAS | | | George Town | 1.05 | 1.02 | Not applicable | 2.00 | 1.09 | 1.07 |
| TAS | T2 | North West Tasmania | Smithton | 1.05 | 1.03 | Not applicable | 1.00 | 1.08 | 1.07 |
| TAS | | | Queenstown | 1.25 | 1.02 | Not applicable | 2.00 | 1.60 | 1.43 |
| TAS | T3 | Central Highlands | Campbelltown | 1.1 | 1.01 | Not applicable | 1.00 | 1.24 | 1.17 |
| TAS | | | Derwent Valley | 1.05 | 1.01 | Not applicable | 3.00 | 1.11 | 1.08 |
| TAS | | | Oatlands | 1.1 | 1.01 | Not applicable | 4.00 | 1.24 | 1.17 |

[1] Note 1: Installation cost factors for some locations appear to be high as their location factors are high and calculations are done on a weighted basis involving low contributions of equipment cost factors.

# 12 New Entrant Technologies – Possibilities of Any Technical Life Extension, Asset Retirement, Site Rehabilitation and Recycling

## 12.1 Possibilities of any technical life extension including any refurbishment requirements to extend the plant's technical life

### 12.1.1 Solar PV plants

Solar PV plants have a technical (economic) and operational life of 30 years. Manufacturers provide warranties of PV module output within this technical life which considers degradation within this period. A condition assessment will need to be undertaken at the end of the plant's technical life to determine areas that require refurbishment and/or upgrade. With these refurbishments and/or upgrades, it may be possible to extend the technical life of the plant up to nominally 40 years. There may be some critical areas that may prevent the technical life extension, such as corrosion of piles or unavailability of spare parts. Depending upon the condition of the plant and the requirement of associated refurbishment costs, plant owners may decide to either retire/decommission the whole plant or proceed with the life extension. Some owners plan to undertake on-going maintenance of the plant keeping in mind a life extension of 40 years. The following table provides a guide for such ongoing maintenance areas.

Table 12-1 Suggested ongoing maintenance activities for utility scale solar farms with an assumed life of 40 years

| Item | Maintenance activity |
|---|---|
| Central inverters | Midlife refurbishment required within the window of operating year 26-30. Timing will be dependent upon cost/benefit trade-off of ongoing plant performance and availability. Requires cooling system and IGBT stack overhaul |
| Trackers and piles | Requires tracker motors and control system overhaul, cathodic protection or structural strengthening within operating year 10-40. |
| Substation | Minor sustaining capital requirement (e.g. gasket replacement, repainting, oil top-ups), noting taking on risk of major failure and related availability reduction. Opportunity for managing the unplanned maintenance through allocation of strategic spares across a portfolio. Depending on ongoing transformer condition, a one-off refurbishment cost could be incurred between years 20-25 to extend the life of the plant to 40-50 years. |
| SCADA | SCADA and communications equipment replacement every 10 years from year 15 |

### 12.1.2 Wind farms

Wind farms typically have a design life of 25 years based on the design life specified in the independent type certification of the turbine under the relevant standard IEC61400-1. However, economic life is often assumed to be 30 years under normal operating conditions and a number of wind turbine suppliers offer long-term service agreements for 30 years including an availability guarantee. O&M fees in these agreements typically ratchet up in the later years to cover the cost of increasing component failures within the turbine. Design life of balance of plant including foundations and electrical reticulation system are typically longer than turbine design life.

There is limited experience in the market with end-of-life reliability of turbines as only small turbines of around 1 MW capacity have reached 25-30 years of operations, and these machines are quite different from the modern large turbines being installed today. However, typical failure rates for turbine components have been studied, which allows some analysis of reliability in later operating years.

Most current wind projects assume an extended economic life of up to 35 years in order to optimise project economics. Various approaches to life extension are taken in the market with some project owners allowing for additional O&M costs in later years to maintain high availability, and others adopting more of an asset-sweating approach and budgeting for reducing turbine availability in later years as component failure rates increase and turbines are progressively taken offline. Both approaches are valid for the purposes of economic modelling. Additional O&M costs can take the form of capital budgets for refurbishment of turbines around year 20 to ensure they can operate for the extended life, of increased O&M costs for labour and parts to repair components as they fail. Main structural components like towers, bed plates, nacelles and rotor hubs are not usually expected to fail within the extended life period but smaller mechanical and electrical components such as gearboxes, shafts, bearings, motors, blades, control boards, sensors etc typically have design lives shorter than the overall turbine design life and therefore need to be replaced, repaired or refurbished at some point.

### 12.1.3 BESS plants

Lithium Iron Phosphate (LFP) batteries are typically warranted for 20 years, with an average cycling duty of 1 cycle per day. As such, BESS facilities typically have a 20 year design life. LFP batteries are commonly considered by battery OEMs to have a useful life up until the State of Health (SOH) of the batteries drops to approximately 60% of the Beginning of Life (BOL) capacity. The ageing behaviour of lithium-ion batteries is approximately linear down to this SOH, however the degradation process starts to accelerate below approximately this level. This is caused by lithium-plating, which consumes the lithium-ions and reduces the storage capacity. As the battery cells enter this phase of life they are also more susceptible to short-circuit faults and failure.

After a 20 year warranted life, the battery cell SOH may typically be in the range of approximately 60 – 68%. While it is not industry standard for extended warranties to be offered beyond 20-years, if the SOH is still some margin above 60%, then it may be possible to extend the useful life of the facility until the batteries attain approximately 60% SOH. It should be noted that this is based on general OEM and industry expectations regarding life to approximately 60% SOH. However, there is not yet industry experience in such life extensions to validate these expectations.

It should also be noted that other equipment such as inverters are expected to reach end of life at approximately 20 – 25 years and may need increased corrective maintenance to extend project life beyond approximately 20 years. Some other balance of plant equipment such as transformers typically have a longer design life of up to approximately 30 years. Earthing, below ground works, and civil works typically also have a longer design of up to approximately 50 years. This can enable project condition assessments to be undertaken as a project approaches the end of its initial design life, and life extension strategies to be developed to make use of the residual design life of parts of the facility.

## 12.2 Qualitative assessment of asset retirement, site rehabilitation and recycling

### 12.2.1 Introduction

The decommissioning, demolition and remediation of a power station facility involves a series of processes which are typically required ranging from initial works to make the facility safe through to total removal and site clean for reuse.

The decommissioning, demolition and rehabilitation would involve the following processes.

### 12.2.2 Plant and system isolations

All equipment and plant systems would be isolated, disconnected and made safe. The electrical connection to the grid would be removed and a supply from the local distribution authority would be installed. Where possible, new electrical supplies would be run as required to maximise safety of the decommissioning workforce. Electrical supplies would be maintained to lighting, essential pumping systems (drainage and sewage) and elevators where required.

Essential fire protection systems (water based) would be identified and left in place to assist during the decommissioning process.

The transmission network equipment on the site may be removed at the discretion of the network operator. This would include the switchyard and its equipment and any redundant transmission lines.

### 12.2.3 Plant decommissioning

#### Removal of plant and equipment

Plant and equipment would be dismantled and removed from the site. The process for elevated items of plant would vary depending on the nature of the equipment being removed. Large items would normally be lowered by cranes. The controlled collapse/dropping of some items would occur also. Such processes would be covered by the relevant statutory requirements.

#### Demolition of buildings and structures

Buildings and structures would be demolished once the removal of internal plant and equipment from each building or structure was completed. Prior to demolition, the building or structure would require certification that all hazardous substances had been removed. The demolition process would be machinery based with the use of excavators and cranes as required.

### Disposal of waste

Some materials liberated during the decommissioning process would be recycled. All remaining waste from the decommissioning process would be disposed of in approved landfills. Any asbestos waste would be disposed of in appropriately licensed landfills.

### Site rehabilitation

After infrastructure has been decommissioned, rehabilitation of the land will follow the sequence required by relevant development approval conditions. These activities include:

- Soil removal/respreading
- Seedbed preparation
- Direct seeding
- Fertilisation
- Tree planting
- Landscaping
- Pest management
- Land Management

A suitably experienced and qualified entity will complete the rehabilitation to ensure it meets relevant development approvals.

## 12.3 Site retirement and decommissioning of new entrant technologies

### 12.3.1 Wind farm site

A wind farm site will typically include:

- Wind Turbine Generators
- Substations
- Reticulation
- Access roads
- Hardstands
- Meteorological towers
- Control systems and offices
- Maintenance warehouses
- Perimeter fencing

The wind turbine tower contains the most significant volume of materials within a typical WTG. Turbine towers are typically constructed using a combination of steel and iron materials.

Wind turbine blades are constructed of high-tensile-strength fibres combined with polymer resins to create glass-fibre-reinforced (GFRP) or carbon-fibre-reinforced polymers (CFRP), referred to more generally as composite materials. Anywhere between 80 – 90% of the blade is made from these composite materials.

The nacelle of a typical WTG contains a mix of materials due to the many functions that it performs. A nacelle will often contain:

- Pitch control
- Gearbox (if not direct drive)
- Drive shafts (if not direct drive)
- Generator
- Wind control
- Brakes

### Wind farm site decommissioning process

Decommissioning a Wind Turbine site generally involves removing wind turbines, site offices, transformers, electrical equipment, and other ancillary infrastructure. Existing roads, access tracks and hardstands may either be removed, and the area revegetated, or potentially kept in place if they continue to serve a purpose for the host landowner.

Wind Turbine foundations are typically significant concrete structures, often as deep as 3m. In all cases, foundations should be at least covered with soil to at least 500mm below ground level and revegetated. Some sites may allow for less backfilling cover depending on the condition of the land, however 500mm which includes 200 mm of topsoil is standard to allow sufficient growth medium for seeding and planting.

Warehouses and other installations may be left if agreed upon by the landowner.

The process of decommissioning an individual turbine will take place over multiple days and involve a team of workers and heavy plant to disassemble the turbine, typically in reverse order to that in which it was constructed. Alternatively, a turbine can be felled via a controlled fall process to disassemble. Once grounded, the turbine will be cut via the same process.

### Waste and recycling

Following decommissioning, the components can be broadly sorted into recyclable, non-recyclable, or difficult-to-recycle materials. The turbine tower, made of steel and iron, contains primarily recyclable materials. Once scrapped, the metal will be sorted, processed, and returned to use.

The composite turbine blades can be difficult to break down into their base components, which results in difficulty in achieving effective, large-scale recycling of the blades. Though recycling potential does exist, it is currently limited and not applicable for a full-site solution. In future, as recycling options become readily available, they should be utilised to reduce the impact on the environment. Until then, it has been assumed that the composite materials, internal electronics, and lubricants will be sent to landfill at their end-of-life.

## 12.3.2 Solar farm site

A typical solar farm would contain the following:

- Solar photovoltaic modules, arranged in panels on steel frames
- Tracking equipment
- Inverters
- Transmission lines
- Access roads
- Meteorological towers

- Control systems and offices
- Maintenance warehouses
- Perimeter fencing

A Photovoltaic (PV) solar energy system comprises multiple solar modules arranged into a panel. The farm consists of numerous panels arranged into an array. Each module contains solar cells arranged into layers that include plastics, silicon, and glass; these layers are enclosed in a steel frame.

### Solar farm site decommissioning process

The typical process for the decommissioning of a large-scale solar farm would require manual dismantling of each string or collection of panels. The piles that the panels are arranged on would be removed from the ground using specialist excavator attachments.

Inverter stations can be transported individually either for reuse or disposal by loading on to a truck once all cabling has been cut and removed.

Once all above-ground infrastructure is removed the final remaining concrete pads can be broken down and transported off site to allow for land rehabilitation. Table 5 presents the decommissioning process in sequence for a solar farm.

### Solar farm waste and recycling

Solar panels have limited recycling potential at this time, with the frame and junction box being the only parts available for recycling. There is growing support for further recycling options within Australia, but as of 2023, they have yet to result in a large-scale solution; any panels not reused or donated in some way will go to a landfill. Currently, Victoria is the only state to have banned sending e-waste (including solar panels) to landfill, and New South Wales has approved investments in solar panel recycling to increase the number of recycling options available. However, most other states have yet to commit to similar regulations or investments. The federal government is investigating the need for a national approach to solar panel recycling and has proposed regulations regarding the end-of-life of panels. This legislation may include mandatory reporting for the disposal of solar panels.

## 12.3.3 Battery Energy Storage System (BESS) site

A typical Battery Energy Storage System (BESS) site would include the following:

- The battery modules
- Inverters
- Substations
- Transmission lines
- Access roads
- Control systems and offices
- Maintenance warehouses
- Perimeter fencing

BESS systems commonly use lithium-ion (Li-ion) battery cells due to multiple benefits including a high energy density. An individual cell contains many different materials, and the makeup of the anode and cathode can vary depending on the chosen battery style. Cell materials generally include Lithium, cobalt, nickel, manganese, graphite, aluminium, copper, steel and iron in varying proportions.

## BESS decommissioning process

Often suppliers of battery modules for commercial use have an agreement to fulfil the recycling responsibilities for the modules. This arrangement is common due to the value of the materials contained in the battery, which can be reused for further manufacturing. These external decommissioning expectations must be clarified with the supplier at time of installation and again before removal. Most BESS modules can be removed as whole pieces with minimal deconstruction needed and loaded by crane on to a truck for transportation.

The remaining infrastructure will be common between BESS and other energy sites and require similar disconnection and removal steps. Cabling will be left on site if below the required depth for successful rehabilitation, cabling closer to the surface will be extracted and taken for recycling. Concrete pads will be crushed and removed from site so land rehabilitation can begin.

## BESS site waste and recycling

Large lithium-ion batteries have complex supply chain involving packaging, system assembly, transportation, and sales organisations. The recycling industry still needs to be developed for batteries of this size, as companies are not yet required to have an end-of-life plan. There are only a small number of battery recyclers in Australia, and most collect and export batteries for processing. Envirostream is the only company involved in pre-processing end-of-life batteries and other e-waste; however, many of the valuable materials are recovered off-shore.

As stated before, some suppliers of battery modules for commercial use have an agreement to fulfil the recycling responsibilities for the modules.

# Appendix A
# AEMO GenCost 2024 Excel Spreadsheet

Spreadsheet to be provided separately

Document prepared by

**Aurecon Australasia Pty Ltd**
ABN 54 005 139 873

Ground Floor, 25 King Street
Bowen Hills QLD 4006

Locked Bag 331
Brisbane QLD 4001
Australia

**T** +61 7 3173 8000
**F** +61 7 3173 8001
**E** brisbane@aurecongroup.com
**W** aurecongroup.com

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