2022 Costs and Technical Parameter Review

2022 Costs and Technical Parameter Review

Australian Energy Market Operator

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Contents

1 Introduction 1

1.1 Background 1
1.2 Scope of Study 1
1.3 Abbreviations 2

2 Limitations 4

2.1 General 4
2.2 Thermoflow Inc. Software 4
2.3 Costs and budget 4

3 Methodology and definitions 5

3.1 Methodology 5
3.2 Assumptions and basis 5

3.2.1 General 5
3.2.2 Power generation / storage facility 5
3.2.3 Fuel connection/ transport 7
3.2.4 Natural gas compression and storage 7
3.2.5 Hydrogen -based technologies and storage 8
3.2.6 Ammonia production facility 10
3.2.7 Carbon capture and storage 10
3.2.8 Development and land costs 10
3.2.9 Financial assumptions 10
3.2.10 Global supply chain cost issues 11

3.3 Definitions 12

4 Generation Technologies 14

4.1 Overview 14
4.2 Onshore Wind 14

4.2.1 Overview 14
4.2.2 Typical options 14
4.2.3 Recent trends 14
4.2.4 Selected hypothetical project 15
4.2.5 Cost estimate 17

4.3 Offshore Wind 17

4.3.1 Overview 17
4.3.2 Typical options 18
4.3.3 Recent trends 18
4.3.4 Selected hypothetical project 19
4.3.5 Cost estimate 20

4.4 Large-scale solar photovoltaic (PV) 22

4.4.1 Overview 22
4.4.2 Typical options 22
4.4.3 Recent trends 23
4.4.4 Selected hypothetical project 23
4.4.5 Cost estimate 24

4.5 Concentrated Solar Thermal 25

4.5.1 Overview 25
4.5.2 Typical options 26
4.5.3 Recent trends 26

4.5.4 Selected hypothetical project 28
4.5.5 Cost estimate 29
4.6 Reciprocating Engines 30
4.6.1 Overview 30
4.6.2 Typical options 30
4.6.3 Recent trends 31
4.6.4 Selected hypothetical project 31
4.6.5 Cost estimate 32
4.7 Open Cycle Gas Turbine 33
4.7.1 Overview 33
4.7.2 Typical options 33
4.7.3 Recent trends 34
4.7.4 Selected hypothetical project 34
4.7.5 Cost estimate 36
4.8 Combined Cycle Gas Turbine 37
4.8.1 Overview 37
4.8.2 Typical options 37
4.8.3 Recent trends 37
4.8.4 Selected hypothetical project 38
4.8.5 Cost estimate 40
4.9 Bioenergy 41
4.9.1 Scope for 2022 Report 41
4.9.2 Emerging sustainability issues 42
4.9.3 Biogas systems 42
4.9.4 Biomass generators using wood waste 48
4.9.5 Biodiesel production 52
4.10 Waste to Energy Plants 60
4.10.1 Overview 60
4.10.2 Mass burn technology (incineration of waste) 60
4.10.3 Gasification of waste 61
4.10.4 Combustion of refuse derived fuel (RDF) in boilers 61
4.10.5 Recent trends 61
4.10.6 Selected hypothetical project 61
4.10.7 Cost estimate 63

5 Hydrogen based technologies and storage 64
5.1 Overview 64
5.2 Reciprocating engines 64
5.2.1 Overview and typical options 64
5.2.2 Recent trends 64
5.2.3 Selected hypothetical project 65
5.2.4 Cost estimate 66
5.3 Gas turbines, including hydrogen conversion of gas turbines 67
5.3.1 Overview and typical options 67
5.3.2 Recent trends 68
5.3.3 Selected hypothetical project 68
5.3.4 Cost estimate 70
5.4 Electrolysers 72
5.4.1 Overview 72
5.4.2 Typical options 72
5.4.3 Recent trends 73
5.4.4 Selected hypothetical project 74
5.4.5 Cost estimate 76

5.5 Hydrogen Fuel Cells 78
5.5.1 Overview 78
5.5.2 Typical options 79
5.5.3 Recent trends 79
5.5.4 Selected hypothetical project 80
5.5.5 Cost estimate 81
5.6 SMR & CCS 82
5.6.1 Overview 82
5.6.2 Current trends 82
5.6.3 Selected hypothetical facility and cost estimate 83
5.7 Hydrogen Storage 84
5.7.1 Overview and selected options 84
5.7.2 Recent trends 84
5.7.3 Selected hypothetical project and cost estimate 85
5.7.4 Hydrogen pipelines and associated costs 86
5.8 Geological hydrogen storage 88
5.8.1 Overview 88
5.8.2 Recent trends 89
5.8.3 Selected hypothetical project and cost estimate 90

6 Ammonia Production Facility 92
6.1 Overview 92
6.2 Recent Trends 92
6.3 Selected Hypothetical Project 93
6.4 Cost Estimate 94

7 Desalination and Water Treatment 95
7.1 Desalination Plant 95
7.1.1 Overview 95
7.1.2 SWRO process description 95
7.1.3 Recent trends 95
7.1.4 Selected hypothetical project 96
7.1.5 Cost estimate 96
7.2 Water Treatment (demineralisation) for Hydrogen Production 97
7.2.1 Overview 97
7.2.2 Processing technology 97
7.2.3 Selected hypothetical project 98
7.2.4 Cost estimate 98

8 Battery Energy Storage System (BESS) 100
8.1 Large-Scale Lithium-Ion Battery Storage 100
8.1.1 Overview 100
8.1.2 Typical options 100
8.1.3 Recent trends 101
8.1.4 Selected hypothetical project 102
8.1.5 Cost estimate 104
8.2 Residential Battery Storage 105
8.2.1 Overview 105
8.2.2 Typical options 106
8.2.3 Recent trends 106
8.2.4 Selected hypothetical project 107
8.2.5 Cost estimate 108
8.3 Large-Scale Sodium Sulphur Battery Storage 109

8.3.1 Overview 109
8.3.2 Deployed capacity 110
8.3.3 Use cases 111
8.3.4 Commodity risks 111
8.3.5 Development and cost trends 112

9 Compressed Air Energy Storage System 113
9.1 Overview 113
9.1.1 Typical options 113
9.1.2 Recent trends 114
9.1.3 Selected hypothetical project 115
9.1.4 Cost estimate 116

10 Capacity Factors for New Solar and Wind Generators 118
10.1 General 118
10.2 Capacity factor drivers 118
10.3 Capacity factor projections 119

Appendices

Appendix A
AEMO GenCost 2022 Excel Spreadsheet

Figures

Figure 4-1: Bioenergy systems utilizing renewable feedstocks
Figure 4-2: Schematic process diagram of fast pyrolysis and hydroprocessing technology
Figure 4-3: Production volume of biodiesel in Australia from 2012 to 2021
Figure 5-1: Hydrogen storage tank, Cape Canaveral (picture NASA)
Figure 5-2: Salt cavern storage schematic (Ozarslan, 2012)
Figure 5-3: Global salt deposit locations (Engie, 2019).
Figure 8-1: NaS battery chemistry
Figure 8-2: NGK Insulators Insulation Record
Figure 9-1: Hydrostor A-CAES Technology (Ref: TWD Report – Independent Engineering Assessment of Scalable 100MW A-CAES Design, 2021

Tables

Table 1-1: Acronyms / Abbreviations
Table 3-1: Power generation / storage facility key assumptions
Table 3-2: Power generation / storage facility terminal points
Table 3-3: Definition of key terms
Table 4-1: Configuration and performance
Table 4-2: Technical parameters and project timeline
Table 4-3: Cost estimates
Table 4-4: Configuration and performance
Table 4-5: Technical parameters and project timeline
Table 4-6: Cost estimates
Table 4-7: Cost estimates
Table 4-8: Configuration and performance
Table 4-9: Technical parameters and project timeline
Table 4-10: Cost estimates

Table 4-11: Configuration and performance
Table 4-12: Technical parameters and project timeline
Table 4-13: Cost estimates
Table 4-14: Configuration and performance
Table 4-15: Technical parameters and project timeline
Table 4-16: Cost estimates
Table 4-17: Configuration and performance
Table 4-18: Technical parameters and project timeline
Table 4-19: Cost estimates
Table 4-20: Configuration and performance
Table 4-21: Technical parameters and project timeline
Table 4-22: Cost estimates
Table 4-23: Biogas hypothetical plant configuration and performance
Table 4-24: Biogas hypothetical project timeline
Table 4-25: Cost estimates for the hypothetical Biogas project
Table 4-26: Configuration and performance
Table 4-27: Technical parameters and project timeline
Table 4-28: Cost estimates
Table 4-29: Biodiesel hypothetical biodiesel plant configuration and performance
Table 4-30: Project timeline
Table 4-31: Hypothetical biodiesel project cost estimates
Table 4-32: Configuration and performance
Table 4-33: Technical parameters and project timeline
Table 4-34: Cost estimates
Table 5-1: Configuration and performance
Table 5-2: Technical parameters and project timeline
Table 5-3: Cost estimates
Table 5-4: Hydrogen turbine configuration and performance
Table 5-5: Hydrogen turbine technical parameters
Table 5-6: Hydrogen turbine cost estimate
Table 5-7: Electrolyser configuration and performance
Table 5-8: Technical parameters and project timeline
Table 5-9: Cost estimates
Table 5-10: Projected EPC cost for 20-30 MW electrolyser plant, 2022
Table 5-11: Fuel cell configuration and performance
Table 5-12: Technical parameters and project timeline
Table 5-13: Cost estimates
Table 5-14: SMR plant criteria
Table 5-15: SMR plant Cost estimate
Table 5-16: Liquid hydrogen storage hypothetical Technical parameters
Table 5-17: Liquid hydrogen storage hypothetical project Cost parameters
Table 5-18: Indicative costs for a new hydrogen distribution network
Table 5-19: Geological Storage Technology Comparison
Table 5-20: Geologic hydrogen storage operating sites (Zavir, Kumar, Foroozesh, 2021)
Table 5-21: Hypothetical Geologic Storage Project Parameters
Table 5-22: Hypothetical Project CAPEX and OPEX costs
Table 6-1: Hypothetical ammonia production facility configuration and performance data
Table 6-2: Hypothetical ammonia production facility technical parameters and project timeline
Table 6-3: Hypothetical ammonia production facility cost estimate
Table 7-1: Cost estimate for full-scale desalination for 100,000 ML/year plant to produce potable water
Table 7-2: Demineralisation process for different water source
Table 7-3: Process parameter of a demineralised plant for a 10 MW electrolyser plant using potable water
Table 7-4: Water treatment plant cost estimate (10 MW electrolyser plant)
Table 8-1: BESS configuration and performance
Table 8-2: Technical parameters and project timeline
Table 8-3: Cost estimates
Table 8-4: RBESS configuration and performance

Table 8-5: RBESS technical parameters and project timeline
Table 8-6: Cost estimates
Table 8-7: Comparison of technical parameters of NaS and Li-ion batteries
Table 8-8: List of current NaS batteries in use
Table 9-1:: A-CAES configuration and performance
Table 9-2: Technical parameters and project timeline
Table 9-3: Cost estimates
Table 10-1: Capacity Factors for new solar and wind generators

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 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, and sea water desalination technologies 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)
- Concentrated solar thermal (with 12 - 15 hours energy storage)
- Hydrogen-based reciprocating engines and gas turbines
- Reciprocating engines
- Open-cycle gas turbine (OCGT)
- Combined-cycle gas turbine (CCGT) (with and without carbon capture and storage (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 8 hours storage
- Alternative battery technology such as sodium sulphur battery
- 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 2022 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
A-CAES	Adiabatic Compressed Air Storage System
CAES	Compressed Air Storage system
AD	Anaerobic Digestion
AEMO	Australian Energy Market Operator
AFC	Alkaline fuel cell
AUD	Australian Dollar
BESS	Battery Energy Storage System
C&I	Commercial and Industrial
CAPEX	Capital Expenditure
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon capture and storage
CHP	Combined Heat and Power
COD	Commercial Operation Date
DMFC	Direct methanol fuel cell
DNI	Direct Normal Irradiance
EPC	Engineer Procure and Construct
FAME	Fatty Acid Methyl Ester
FCAS	Frequency control ancillary services
FFA	Free fatty acid
FFR	Fast Frequency Response
FGD	Flue gas desulfurization
GHS	Geologic hydrogen storage
GJ	Gigajoule
GPS	Generator performance standards
GST	Goods and Services Tax
GT	Gas turbine
HDPE	High density polyethylene
HHV	Higher Heating Value
HTL	Hydrothermal liquefaction
ISP	Integrated system plan
KHI	Kawasaki heavy industry
LCOE	Levelised Cost of Electricity
LFP	Lithium iron phosphate

Acronym	Definition
LHV	Lower Heating Value
MCR	Maximum Continuous Rating
MW	Megawatt
MWh	Megawatt-hour
NEG	National electricity grid
NEM	National Electricity Market
NTP	Notice to Proceed
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
O&M	Operations and Maintenance
PAFC	Phosphoric acid fuel cell
PEM	Proton Exchange Membrane
PEMFC	Proton exchange membrane fuel cell
PV	Photovoltaic
PVC	Polyvinyl chloride
RBESS	Residential battery energy storage system
RDF	Refuse-derived fuel
RR	Recovery ratio
SAT	Single-axis Tracking
SCR	Selective catalytic reduction
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
TRL	Technology readiness level
UCO	Used cooking oil
VNI	Victoria to NSW interconnector
VPP	Virtual power plant
WEM	Wholesale Electricity Market
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, 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 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.

This report is partly based on information provided to Aurecon by AEMO. This report is provided strictly on the basis that the information provided to Aurecon is accurate, complete and adequate, unless stated otherwise.

If AEMO or a third party should become aware of any inaccuracy in, or change to, any of the facts, findings or assumptions made either in this report or elsewhere, AEMO or a third party should inform Aurecon so that Aurecon can assess its significance and review its comments and recommendations.

2.2 Thermoflow Inc. Software

This report relies on outputs generated from Thermoflow Inc. software by personnel in Aurecon experienced in using this software. The provider of this software does not guarantee results obtained using this software, nor accept liability for any claimed damages arising out of use or misuse of its software. Aurecon's report is provided strictly on the basis that the outputs that have been generated are accurate, complete, and adequate. Aurecon takes no responsibility and disclaims all liability whatsoever for any loss or damage that AEMO may suffer resulting from any conclusions based on outputs generated by Aurecon using this software.

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Aurecon has no control over the cost of labour, materials, equipment, or services furnished by others. Aurecon similarly has no control over Contractors' methods of determining prices, or over competitive bidding or market conditions. Any opinion or estimate of costs by Aurecon is made on the basis of Aurecon's experience and qualifications, and represents Aurecon's judgment as an experienced and qualified professional engineering organisation, familiar with the construction industry. However, Aurecon cannot and does not guarantee that proposals, bids, or actual construction costs will not vary from Aurecon's estimates.

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 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 regional or remote cost factors, etc). There exists uncertainties on technology performance and cost estimates for new/emerging technologies, such as hydrogen and ammonia production.

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 construction
- Recent bid information from EPC competitive tendering processes
- Industry publications, publicly available data, 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 2022 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 following table.

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)
Base ambient conditions:	Dry Bulb Temperature: 25 °C Elevation above sea level: 110 metres Relative Humidity: 60%
Fuel quality	Gas: Standard pipeline quality natural gas (HHV to LHV ratio of 1.107) Diesel: No.2 diesel fuel Biomass: Woodwaste Waste: Municipal solid waste
Water quality	Towns water quality (i.e. potable) Demineralised water produced on site if required
Hydrogen quality	99.99+% v/v in compliance with ISO 14687-2:2014 and SAE J2719. HHV to LHV ratio of 1.183
Grid connection voltage	220 – 275 kV (or lower for small scale options (i.e. electrolysers, etc))
Grid connection infrastructure	Step-up transformer included; switchyard / substation excluded
Energy Storage	Concentrated solar thermal – 12 hrs thermal energy storage considered Electrolysers / hydrogen power generation (fuel cells / reciprocating engines / turbines) – Hydrogen compression, transport and storage excluded (relative costs provided separately) BESS – 1, 2, 4, and 8 hour energy storage options considered
Project delivery	EPC turn-key basis
O&M approach	Thermal/hydrogen power generation: Owner operates and maintains, but contracts for scheduled maintenance 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 the following table. Communication links are considered to be generally 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 (if relevant)	Gas: 30 – 40 bar supply pipeline at site boundary, dry and moisture free Diesel: Truck unloading facility located on site Biomass and waste: Truck unloading facility located on site
2	Grid connection	HV side of generator step-up transformer
3	Raw / potable water	Site boundary (Water treatment plant included in project scope if demineralised water required)
4	Wastewater	Site boundary
5	Road access	Site boundary
6	Hydrogen supply (if relevant)	Electrolyser: Outlet of package at delivery pressure (i.e. no additional compression) Fuel cell: 10 bar supply pipeline at package inlet Reciprocating engine: 10 bar supply at package boundary Turbine (small): 30 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 biomass and waste fuel connection scope assumptions are as follows:

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

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.

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 (e.g.: Natural gas) with steam which causes (ultimately) the breakdown to hydrogen and carbon dioxide. In this report, electrolysis and Steam Methane Reformation (SMR) have been considered.

PEM and Alkaline electrolyser technology have been considered. Other electrolyser facility assumptions for the hypothetical project considered in this report and associated costs are included in Section 5.4.1 and Section 5.4.5.

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 diaphragm type
- Supply pressure: 30 bar (for PEM) or 1 bar (for Alkaline). Discharge pressure: 100 bar
- Capacity: Between 1,850 and 2,000 Nm^3/h (1 x 100% duty)
- 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 kgH_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).

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: DN50 (suitable for up to single 20 MW electrolyser)
- 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 (e.g.: compression and storage facilities combined) rather than component costs and, considering the nature of this report, they are considered appropriate.

The costs for hydrogen storage are based upon either a liquefaction and cryogenic storage facility or underground storage. The liquefaction facility is based upon the upper end of a hydrogen liquefaction plants existing today the largest existing is approximately 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 10% of NSW 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:

- 100% hydrogen reciprocating engine plant with capacity factor to align with hydrogen production available with storage from a 10 MW electrolyser plant at 80% capacity factor
- 100% hydrogen turbine small scale with capacity factor to align with hydrogen production available with storage from a 10 MW electrolyser plant at 80% 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
- 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.

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
- 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. An indicative estimate has been determined based on a percentage of CAPEX estimate for each technology from recent projects, and experience with development processes.

3.2.9 Financial assumptions

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

- Prices in AUD, 2022 basis for financial close in 2022. 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

- Assumes foreign exchange rates of 0.65 AUD:USD and 0.64 AUD:EUR
- 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

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.

3.2.10 Global supply chain cost issues

The global construction industry is currently quite volatile and the ability to predict what the long-term inflationary impact is on construction and operating costs is difficult to quantify. For industries using a high amount 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 2021 costs.

At the moment the construction industry is experiencing increases in the following building materials, along with supply chain issues:

- Timber costs continue to rise, with cladding, decking and other timber items affected.
- Steep rises in metal prices are also now flowing through to the market, with structural steel, fixings and metal components hit hard.
- Continued volatility in the rest of the construction market, with imported products the most vulnerable due to elevated shipping costs.
- Rising fuel costs have contributed to further increases in the cost of other materials.
- Labour shortages

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

- Lithium carbonate price increases impacting BESS prices
- Global competition for key components and technologies impacting wind turbine prices
- EPC Contractor resourcing constraints and risk appetites increasing EPC pricing in general

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 2022 report to allow for uncertainty and movement in construction costs, as well as for operating costs over the life of the project.

A shortage of key materials such as structural members and metal products, along with higher fuel costs, and labour shortages, is likely to keep upwards pressure on building costs for some time yet.

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). *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 longer 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 of time 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. 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. 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. 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). *Note Specific formulas are as defined in IEEE Std. 762.*

Term	Definition
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 i.e. while maintaining acceptable frequency and voltage control.
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 – i.e. 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. *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. *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 ($/MW Net/year)	Fixed costs include; plant O&M staff, insurance, minor contract work, and miscellaneous fixed charges such as service contracts, overheads, and licences. For some technologies where operation and maintenance are holistically covered by O&M and/or LTMA type contracts, all of the Operating Costs have been classed as "fixed" for the purposes of this study.
Variable operating cost ($/MWh Net)	Variable costs include; spare parts, scheduled maintenance, and consumables (chemicals and oils). 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)/tNH_3
Water consumption	Water required to produce per tonne of ammonia, m^3/t(NH_3), or required to produce per kg hydrogen (L/kgH_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 bio-energy), 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 2022 Excel spreadsheets, which are included in Appendix A.

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 turbines (HAWT), with the blades upwind of the tower. These turbines are designed for a range of wind conditions with some optimised for low wind speed sites and some designed for high wind speed sites. Grid-connected wind turbines are considered a reliable and mature technology with many years of operational experience.

4.2.2 Typical options

Previously installed utility-scale wind turbine sizes range from 1 to 5 MW, with the newest around 6 MW, hub heights of 50 to 150 m and rotor diameters of 60 m to 160 m. New models proposed for near future projects are around 7 MW capacity with rotors around 160-170 m in diameter and hub heights up to 170 m.

Onshore wind developments are critically dependent on:

- Access to land
- Planning permissions / development consents
- Nearby grid transmission capacity

Wind resource, while still important, has become less of a critical factor in project viability as increases in turbine height and rotor diameter along with design improvements have improved the economics of onshore wind projects, which has opened up larger areas for development.

Depending on the above, modern onshore wind farms can range from 1 to over 150 turbines. Different 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.

Modern projects are also increasingly being delivered with a co-located battery and or solar PV plant to reduce intermittency of generation and improve utilisation of connection assets.

4.2.3 Recent trends

The design wind range for wind turbines has changed over the last few decades. Early focus was on very windy sites for best economics e.g. mean wind speeds of 8.5m/s to 10m/s. Wind turbines suitable for these sites now only represent a small fraction of total manufacturing worldwide. Currently, large turbines are being used in medium (7.5 to 8.5 m/s) and low wind speed (6.5 to 7.5 m/s) sites to achieve net capacity factors up to around 40%.

Turbine outputs, hub heights, and rotor diameters are continually being increased, resulting in a general trend of ongoing reductions in LCOE. However, various cost pressures over the last few years, including shipping challenges due to COVID-19 and increases in costs of labour and key commodities, have led to significant increases in turbine costs and associated LCOE of projects. These factors are considered to be relatively temporary but it is unclear when they may reverse and allow turbine prices to return to previous levels. Turbine suppliers are also reviewing their risk appetite in the booming global market noting profitability challenges over the last few years, and may take the opportunity to reset turbine pricing to a more sustainable level. This could mean that pricing does not fully recover to pre-COVID-19 levels even when the recent cost pressures reverse.

For projects that are currently planned and under construction, wind turbine sizes in the 5 – 6 MW range are being used. Projects due for commencement in 20223/2023 are at the upper end of the range and in some cases above.

Wind farm sizes throughout Australia have historically mostly been in the 50 to 150 MW capacity range. However, in recent years new wind farms - *planned and under construction* - are expanding to total capacities in the range of 200 to 1,000 MW.

Typical capacity factors at the connection point range from 30% to 50%. Capacity factors are linked to the wind resource and turbine model used, with the main factor being the size of the rotor relative to the rated power output of the generator. The spacing of turbines within the available land also influences capacity factor due to greater wake losses with tighter turbine spacing. With recent developments in turbine design, capacity factors have been increasing. The most recent onshore wind projects on the NEM have reported capacity factors of approximately 40-45%.

In recent years the development and grid connection of new windfarm projects has become more challenging. Planning applications require that wind turbine maximum tip heights are nominated very early in the approvals process. The rate of new developments in wind turbine technology has been so high that at the time of project execution the planning approvals need to be amended to enable the use of the latest and most economically viable technology. New requirements for grid connection approvals and Generator Performance Standards (GPS) have also been extending the time required 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 windfarms 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 assumed that structural components such as towers and foundations can operate for this extended period.

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 2022, given the above discussion on typical options and current trends.

Table 4-1: Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology / OEM		Siemens Gamesa	Other options include Vestas, GE, Goldwind, etc
Make model		SG 6.0-170	Based on current new installations
Unit size (nominal)	MW	6.0	ISO / nameplate rating
Number of units		50	
Performance			
Total plant size (Gross)	MW	300	
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.
Total plant size (Net)	MW	291	

Item	Unit	Value	Comment
Seasonal rating – Summer (Net)	MW	291	Derating above 30°C based on OEM datasheet. Note derating only occurs in high generation (i.e. high wind) and high temperatures.
Seasonal rating – Not Summer (Net)	MW	291	Accounting for temperature related factors only.
Annual Performance			
Average planned maintenance	Days / year	-	Included in EFOR below.
Equivalent forced outage rate	-	2%	Majority large wind farms currently being constructed in Australia have contractual warranted availability of 98% (or higher) for wind turbines for up to a 25-year period.
Effective annual capacity factor (year 0)	-	40%	Dependent on wake losses, wind resource, and electrical losses. Based on gross capacity.
Annual generation	MWh	1,050,000	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	
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. 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. 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	2022	
EPC programme	Years	2	For NTP to COD.
▪ Total lead time	Years	1	Time from NTP to first turbine on site.
▪ Construction time	Weeks	52	Time from first turbine on site to last turbine commissioned.
Economic life (design life)	Years	20 – 25	Varies between manufactures.
Technical life (operational life)	Years	25 – 35	Includes life extension but not repowering.

4.2.5 Cost estimate

Table 4-3: Cost estimates

Item	Unit	Value	Comment
CAPEX Construction			
Relative cost	$ / kW	2,500	Based on Aurecon internal benchmarks. There has been a significant increase in turbine prices in the last 12-24 months based on shipping constraints, labour issues, and commodity price movements. Relative cost does not include land and development costs.
Total cost	$	750,000,000	
▪ Equipment cost	$	562,500,000	75% of EPC cost – typical.
▪ Installation cost	$	187,500,000	25% of EPC cost – typical.
Other costs			
Cost of land and development	$	18,750,000	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)	25,000	Average annual cost over the design life. O&M costs typically increase steadily over the project life.
Variable O&M Cost	$ / MWh (Net)	-	Included in the fixed component.
Total annual O&M Cost	$	7,500,000	Annual average cost over the design life.

4.3 Offshore Wind

4.3.1 Overview

Offshore wind turbines are fundamentally the same as onshore wind turbines, however they have been designed to survive in the aggressive offshore environment and involve very different foundations.

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
  - can have better temporal alignment with generic demand profiles (i.e. windier in the late afternoon than onshore)
- 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
- Turbines are typically manufactured near canals or ports and barged to site which avoids the need for road and bridge upgrades

A combination of the above factors permits the use of much larger wind turbines offshore which can improve project economics. Commonly cited challenges include:

- Proximity to onshore transmission infrastructure and associated costs
- Harsh conditions from marine operating environment
- Expensive operation and maintenance costs of offshore sites

It is also worth noting that development of an offshore project - *especially given the non-existent offshore wind market in Australia compared to Europe* - would be significantly more complicated and involved than an onshore project, which would impact project development timelines accordingly. This is being experienced by the most advanced currently proposed offshore wind farms in Australia.

4.3.2 Typical options

Existing offshore wind turbines range in nameplate capacity from 3 MW to 16 MW, with correspondingly large rotor diameters but hub-heights in similar or slightly larger ranges than onshore equivalents. Aurecon notes however, that the market is trending towards much larger turbines (see Section 4.3.3 below).

Offshore wind farms are typically larger in both turbine number and total output due to the following:

- Significant capital expenditure associated with the challenging nature of offshore construction and maintenance combined with expensive subsea grid connection requires lager builds to drive down normalised capital and operational costs
- Reduced limitations arising from land parcel boundaries and associated complications

As such it is not uncommon to have offshore projects in development with 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.

Offshore wind turbines are commonly constructed in fjords, lakes and continental shelves with a depth upper limit of 50 – 60 m, noting that:

- Traditionally mounted wind turbines use a single monopile in water depths <30 m
- Tripod, tripile or jacket structures are typically selected for depths of up to 60 m due to economical and practical reasons.

For depths over 60 m, floating structures are proposed with a number of pilot sites installed or in planning. The first commercially operating wind farm using floating type foundation, Hywind Scotland, was commissioned in late 2017[1] and has been followed by Kincardine B in 2020 and Hywind Tampen in 2022. Floating foundation offshore wind farms are still considered to be in the early commercialisation stage with a number of projects under development.

4.3.3 Recent trends

In Europe, the cost of offshore wind has been falling dramatically since 2015, from about 5000 USD / kW down to 2,858 USD / kW in 2021.[2] This reduction has been attributed to the following factors:

- Increased market efficiency through increased constructor competition and competitive auction processes for new projects
- Development of current generation of large turbines (12 – 16 MW)
- Increases in total installed capacity

It should be noted that these cost reductions have been realised off the back of a maturing European development and delivery market. Given that the current offshore development and delivery capability in Australia is virtually non-existent, Aurecon would recommend caution in assuming efficient translation of European costs to Australian projects. If European 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).

In Australia, there are no existing offshore wind projects, and only one which has secured a resource exploration licence (the Star of the South off the coast of Gippsland in Victoria). As such, costs for offshore

1 https://www.windpowerengineering.com/business-news-projects/worlds-first-floating-wind-farm-delivers-promising-results/
2 IRENA (2022), Renewable Power Generation Costs in 2021, International Renewable Energy Agency, Abu Dhabi

wind in Australia are expected to be above the international average until experience is gained and supply chains established. For the purpose of this report, we have considered international average costs without considering any 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 and Table 4-7, connection costs are broadly expected to be in the range of 8-24% of total construction costs. 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 330 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 AUD5.3B, connection cost of AUD900M would represent around 17% of total cost which is broadly consistent with the guidance provided from international benchmarks. However, it is currently unclear whether offshore wind developers will pay for connection costs, noting that recent announcements by the Victorian Government indicate that the new 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 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 2022 (if a project was suitably advanced to start construction) given the above discussion on typical options and current trends.

Table 4-4: Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology / OEM		GE	
Make model		Haliade-X 12 MW	
Unit size (nominal)	MW	12	Modern offshore turbines are very large compared to onshore variants.
Number of units		100	
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. Nominal allowance only. Dependant on distance from shore.
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 (i.e. high wind) and high temperatures.
Seasonal Rating – Not Summer (Net)	MW	1152	
Annual Performance			
Average Planned Maintenance	Days / yr.	-	Included in EFOR below.

Item	Unit	Value	Comment
Equivalent forced outage rate	%	5%	Based on international benchmarks.
Effective annual capacity factor	%	48%	Based on European weighted average benchmarks of 2021.
Annual generation	MWh / yr.	4,843,930	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 4-5: 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			
Time for development	Years	4 – 5	Typical for Europe.
First year assumed commercially viable for construction	Year	2022	
EPC programme	Years	5	For NTP to COD.
▪ Total lead time	Years	3	Time from NTP to first turbine on site.
▪ Construction time	Years	2	Time from first turbine foundation on site to last turbine commissioned.
Economic life (design life)	Years	25	
Technical life (operational life)	Years	30	

4.3.5 Cost estimate

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

Table 4-6: Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	4,388	Based on US$2,858 / kW which was the 2021 global weighted-average installed costs for offshore wind[2]. Capital cost includes a certain percent of grid connection cost, typically 8-24%. It is country specific, and in some countries (e.g. China. Denmark and the Netherlands) developers are not responsible for electrical interconnection. Relative cost does not include land and development costs. Exchange rate at time of print: 1 USD – 1.54 AUD
Total EPC cost	$	5,265,600,000	

Item	Unit	Value	Comment
▪ Equipment cost	$	3,685,920,000	70% of EPC cost – typical.
▪ Installation cost	$	1,579,680,000	30% of EPC cost – typical.
Other costs			
Cost of land and development	$	105,312,000	Assuming 2% of CAPEX due to large project scale.
Fuel connection costs	$	N/A	
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	158,731	Based on an indicative average of 25 Euro/MWh[3]. Exchange rate at time of print: 1 EUR – 1.51 AUD
Variable O&M Cost	$ / MWh (Net)	-	Included in the fixed component.
Total annual O&M Cost	$	190,477,440	Annual average cost over the design life Exchange rate at time of print: 1 EUR – 1.51 AUD

Although IRENA reported a 13% decrease in the globally weighted average costs between 2020 and 2021, strong performance of the USD – AUD has meant that CAPEX costs have remained relatively unchanged to construct a hypothetical project in 2022.

Floating foundation

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

Table 4-7: Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	6,079	Based on US$2,858 / kW which was the 2021 global weighted-average installed costs for offshore wind[2]. Cost increases due to the cost of floating foundations vs fixed bottom foundations[4] Relative cost does not include land and development costs. Exchange rate at time of print: 1 USD – 1.54 AUD
Total EPC cost	$	7,294,491,502	
▪ Equipment cost	$	5,106,144,052	70% of EPC cost – typical.
▪ Installation cost	$	2,188,347,451	30% of EPC cost – typical.
Other costs			
Cost of land and development	$	145,889,830	Assuming 2% of CAPEX due to large project scale.
Fuel connection costs	$	N/A	

[3] P.E. Morthorst, L. Kitzing, "Economics of building and operating offshore wind farms", Technical University of Denmark, Roskilde, 2016

Item	Unit	Value	Comment
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	585,080	Based on an indicative average of 25 Euro/MWh[3]. Cost increases due to risk, uncertainty and current project scaling of floating foundations vs fixed bottom foundations[4] Exchange rate at time of print: 1 EUR – 1.51 AUD A
Variable O&M Cost	$ / MWh (Net)	-	Included in the fixed component.
Total annual O&M Cost	$	702,095,580	Annual average cost over the design life Exchange rate at time of print: 1 EUR – 1.51 AUD

Costing associated with floating foundation wind farms is based on todays 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.

4.4 Large-scale solar photovoltaic (PV)

4.4.1 Overview

Over the last decade, solar PV generation has emerged as a significant growth technology globally. 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 the connection point.

The output of solar PV systems is highly dependent on the availability of solar resource. Generally, the solar resource in Australia is excellent, although slightly less in the south and along the eastern coast. Large-scale solar PV systems are usually located in close proximity to a major transmission line 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, high density ground mount etc may be used, but are less common and typically used for niche applications such as smaller installations and short-term deployments. In fixed-tilt systems, modules are mounted on a static frame, which is generally tilted towards the north. In single-axis tracking systems, 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 than fixed-tilt systems. However, they generally have a lower LCOE, as they produce more energy throughout the day. Some fixed tilt systems are arranged in north-south rows 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.

[4] Floating Offshore Wind: The next five years - DNV, 2022

Solar PV panel (or module) design is another key area which affects overall plant capacity. Historically, mono-facial panels (i.e. 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 option. In Australia most new solar farm projects being constructed are using bi-facial panels.

4.4.3 Recent trends

The widespread deployment of solar PV systems globally has led to significant reduction in the cost of solar panels in recent years. Although the rate of solar panel cost reduction is slowing, investment in the sector is growing, with several large-scale (i.e. >200 MW) solar farms under development in Australia.

Solar farm sizes are also on the upward trend with some projects reaching financial close in 2020 and 2021 being in the 200 to 400 MWac range. This relates primarily to their connection at higher grid voltages and the spreading of fixed project costs across a larger system.

Due to the relatively low cost of the solar PV modules, solar developers are increasingly installing more solar panel capacity than grid connection capacity (i.e. higher DC:AC ratio). Though some power generation is curtailed in the middle of the day in the early years of the project life, this allows a more consistent, flatter generation profile, with increased generation in the early morning and late afternoon. The output of the solar modules typically degrades steadily over the project life, which reduces the level of inverter clipping. Developers are also installing more inverter capacity than grid connection capacity to improve reactive power capabilities and meet NER requirements.

Single-axis tracking systems are becoming widely deployed, due to the increased energy capacity they offer over fixed-tilt systems in the early morning and late afternoon. This results in improved project economics. Single-axis tracking systems that mount two modules in a portrait configuration (known as “2P trackers”) are also an option, allowing 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 utility-scale solar farms under construction typically around 500 W. Bi-facial modules are now offered as standard for utility projects, allowing greater power generation for the same overall footprint at only slightly higher cost than mono-facial modules.

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 generally required.

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 2022, given the above discussion on typical options and current trends.

Table 4-8: Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology		Single Axis Tracking (SAT)	Based on recent trends.
Performance			
Plant DC Capacity	MW	240	
Plant AC Inverter Capacity	MVA	240	Additional reactive power allowance for NER compliance
Plant AC Grid connection	MW	200	Active power at point of connection
DC:AC Ratio		1.2	Typical range from 1.1 to 1.3
Auxiliary power consumption	%	2.9%	Very little auxiliary power consumption during operation but there are electrical distribution losses

Item	Unit	Value	Comment
Total plant size (Net)	MW (AC)	194.2	
Seasonal Rating – Summer (Net)	MW (AC)	194.2	Degradation expected above 35°C. Expect approximately 10% de-rate at 50°C.
Seasonal Rating – Not Summer (Net)	MW (AC)	194.2	
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.	493,345.7	Calculated from capacity factor above.
Annual degradation over design life	%	0.4%	On AC basis.

Table 4-9: Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp Up Rate	MW/min	Resource dependant	
Ramp Down Rate	MW/min	Resource and system dependant	
Start-up time	Min	N/A	
Min Stable Generation	% of installed capacity	Near 0	
Project timeline			
Time for development	Years	2 – 3	
First Year Assumed Commercially Viable for construction	Year	2022	
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 4-10: Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / W (DC)	1.20	Relative cost does not include land and development costs.

Item	Unit	Value	Comment
Total EPC cost	$	288,000,000	
Equipment cost	$	172,800,000	60% of EPC cost – typical.
Installation cost	$	115,200,000	40% of EPC cost – typical.
Other costs			
Cost of land and development	$	17,280,000	Assuming 10% of equipment cost.
Fuel connection costs	$	N/A	
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	17,000	Includes allowance for general spare parts and scheduled replacement capex
Variable O&M Cost	$ / MWh (Net)	-	Included in the fixed component.
Total annual O&M Cost	$	3,400,000	Annual average cost over the design life

4.5 Concentrated Solar Thermal

4.5.1 Overview

Concentrated solar thermal 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 primary types of concentrated solar thermal power plants available in the current market. These include:

- 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 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.
- 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 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 CSP 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 compare 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. Significant cost reductions are expected in the components as design and manufacturing matures and plant sizes increase.

The O&M requirements of solar thermal 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.

4.5.2 Typical options

As mentioned above, the key differentiation of the concentrated solar thermal technologies compared to solar PV or wind is the ability to integrate thermal energy storage. Although inclusion of thermal energy storage increases the installed cost of the plant, current trends show thermal energy storage is being included on most projects under construction and all projects under development[5] .

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[5]. As with many technologies, increases in scale 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. 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. The Vast Solar technology developed in Australia is seeking to overcome this 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.

4.5.3 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 CSP was installed globally, particularly the Middle East, North Africa, and China, and total installed capacity at the end of 2021 was around 7 GW[6].

Global growth in CSP continues 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),

[5] https://itpthermal.files.wordpress.com/2019/02/itpt_csproadmap3.0.pdf
[6] NREL Spring 2022 Solar Industry Update, 26 April 2022

281 GW (by 2040) and 426.5 GW (by 2050)[7]. Xinjiang province in China recently announced 13 concentrating solar-thermal power (CSP) projects totalling 1.35GW would be developed[8] in addition to the 1.1 GW of CSP projects announced by other provinces in January 2022, making China the largest CSP market in the world. The Chinese Solar Thermal Alliance stated that China is pursuing CSP for three applications:

- Firm, dispatchable power to complement wind and PV
- The generation of hydrogen and jet fuels at temperatures up to 1,500 degrees Celsius
- Solar heat for industrial processes.

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[9]. For 2021, IRENA reported average CSP installation costs increased significantly to around USD9,000/kW however this was based on only one project coming online, the 110 MW Cerro Dominador in Chile. This project had a number of delays and construction issues, and also has significantly more storage than other recent projects at 17.5 hours, both of which contribute to the high installation cost. A subsequent project in the same region, the 390 MW Likana CSP Project bid a record-low USD34/MWh which implies that construction costs will be significantly lower than for Cerro Dominador.

Most new international CSP projects are hybrid projects combing CSP 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 CSP 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 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 mid-2023. A 50 MW baseload hybrid solar plant in Mt Isa is also being developed which includes a 56 MW solar tower plant with 14.5 hours thermal energy storage, an 80 MW PV plant, 52 MW/15 MWh BESS, and 57 MW of reciprocating gas engines[10] in order to provide a very high level of reliability for the Mt Isa Network. The project is in late development stage.

We expect that CSP projects in Australia will target dispatchable generation during a 12-15 hour afternoon peak and overnight period, storing energy during the day rather than generating during the day given the significant daytime generation from low-cost solar PV in most parts of Australia, and covering the morning peak until solar PV starts generating again.. This will require a slight increase in the size of the steam generator and turbine relative to the size of solar array but will lead to a reduction in O&M costs for the steam plant.

SolarReserve previously proposed the Aurora Solar Energy Project, a 150 MW solar tower with 8 hours molten salt energy storage to be located in Port Augusta, South Australia (SA). The project entered into a power purchase agreement with the South Australia Government in 2017, but that agreement was terminated in early 2019 following the inability to achieve financial close. Recently, Vast Solar has committed to developing its 30MW commercial reference project on this site.

Given the lack of constructed projects in Australia, there is limited information on the actual costs of solar thermal projects in the region. The available datapoints from international projects is also limited but this will change in the next few years with the significant build programme underway in China and other countries.

CSP plants in Australia are expected to be designed to suit the DNI of the selected site and the proposed dispatch period. At a site with typical DNI of 2,500 kWh/m^2, heliostat mirror area is expected to be around

[7] Net Zero by 2050: A Roadmap for the global energy sector, International Energy Agency (2021)
[8] NREL Summer 2022 Solar Industry Update, 12 July 2022
[9] Renewable Power Generation Costs in 2021, IRENA
[10] https://nwqhpp.com/

11,000 m² per MW of turbine capacity. This would increase to around 12,000 m² per MW to capture the same amount of energy at sites with lower DNI of around 2,200 kWh/m² and decrease to around 10,000 m² per MW at sites with higher DNI of around 2,800 kWh/m². The solar field (heliostats, piping, receiver etc) currently represents around 43% of total capital costs according to IRENA data for 2021, meaning that the solar field sizing is largest influence on capital cost. A figure of $600/m² of heliostat area has been used to develop the capital cost estimate for this report which translates to $6,600/kW for the 200 MW hypothetical project described in the following sections. Using the lower mirror area of 10,000 m² per MW for higher DNI sites with the same turbine capacity, translates to $6,000/kW while the higher mirror area of 12,000 m² per MW increases specific cost to $7,200/kW.

4.5.4 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 2022, given the above discussion on typical options and current trends.

Table 4-11: 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 in a modular array configuration such as Vast Solar's technology. Storing energy during the day and generating for 15 hours through evening peak and overnight period eg 5pm to 8am
Solar field heliostat area	m²	2,200,000	Based on average heliostat area of 11,000 m² per MW of steam turbine capacity for a site with average DNI of around 2,500 kWh/m2
Power block		1 x Steam Turbine, dry cooling system	
Capacity	MW	200	Based on typical options and recent trends, 200 MW with 15 hours thermal energy storage is selected.
Power cycle efficiency	%	45	Typical
Heat transfer fluid		Molten salt	Molten salt is currently the preferred heat transfer fluid for central tower CSP technology
Storage	Hours	15	As mentioned in Section 4.5.3, almost all recent projects have a thermal energy storage component. 15 hours was chosen as representative.
Storage type		2 tank direct	
Storage description		Molten salt	
Performance			
Total plant size (Gross)	MW	200	25°C, 110 metres, 60%RH
Auxiliary power consumption	%	10%	
Total plant size (Net)	MW	180	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	180	

Item	Unit	Value	Comment
Seasonal Rating – Not Summer (Net)	MW	180	
Annual Performance			
Average Planned Maintenance	Days / yr.	7	Based on published figures[11].
Equivalent forced outage rate	%	3%	Based on published figures[11].
Effective annual capacity factor	%	50%	Based on published figures[12].
Annual generation	MWh / yr.	876,000	Provided for reference.
Annual degradation over design life	%	0.2%	Typical for subcritical steam cycle.

Table 4-12: 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 Warm: 50 Cold: –n/a	Standard operation. Cold start time not included as a CSP plant should always remain warm.
Min Stable Generation	% of installed capacity	20%	
Project timeline			
Time for development	Years	2 – 3	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2022	
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	25	
Technical Life (Operational Life)	Years	40	

4.5.5 Cost estimate

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

Table 4-13: Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			

[11] Alinta, 2015. Port Augusta Solar Thermal Generation Feasibility Study
[12] https://itpthermal.files.wordpress.com/2019/02/itpt_csproadmap3.0.pdf

Item	Unit	Value	Comment
Relative cost	$ / kW (gross)	6,600	Very little project information in Australia relating to build cost for CSP plant. Recent international costs and trends as described above. Relative cost does not include land and development costs.
Total EPC cost	$	1,320,000,000	
▪ Equipment cost	$	990,000,000	75% of EPC cost – typical.
▪ Construction cost	$	330,000,000	25% of EPC cost – typical.
Other costs			
Cost of land and development	$	20,000,000	Assuming 1.5% of CAPEX, comprising land costs of around $5,000/Ha for 1200Ha and development costs of around $14M.
Fuel connection costs		N/A	
OPEX – Annual			
Fixed O&M Cost	$ / MW	132,000	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	$	26,400,000	Annual average cost over the design life

4.6 Reciprocating Engines

4.6.1 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 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.

4.6.2 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 heavy 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.

4.6.3 Recent trends

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 dependant on fuel gas availability.

Given the high degree of uncertainty around medium to long-term market conditions, large-scale medium-speed reciprocating engine power stations have increased in popularity in recent times for firming applications. This is driven by their favourable fuel efficiency merits, and high degree of flexibility in start times and turn-down. 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 power station to supply power to FMG's Solomon mine in Western Australia's Pilbara region[13].

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 further:

- AGL's Barker Inlet Power Station (Stage 2 – 210 MW)
- APA's Dandenong Power Project (Stage 1 – 220 MW, Stage 2 – 110 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)[14]

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

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 2022 given the above discussion on typical options and current trends.

Table 4-14: 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
Unit size (nominal)	MW	17.6	ISO / nameplate rating at generator terminals.
Number of units		12	
Performance			
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
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	
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.

[13] https://www.australianmining.com.au/news/fortescue-hands-solomon-energy-contract-to-pacific-energy/
[14] https://www.lochardenergy.com.au/energy-reserve-1-2 /

Item	Unit	Value	Comment
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 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 4-15: 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	2022	
EPC programme	Years	2	For NTP to COD.
▪ Total Lead Time	Years	1	12 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 dependant
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 4-16: Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			

Item	Unit	Value	Comment
Relative cost	$ / kW	1,500	Net basis. Includes liquid fuel storage. Relative cost does not include land and development costs.
Total EPC cost	$	313,650,000	
▪ Equipment cost	$	188,190,000	60% of EPC cost – typical.
▪ Installation cost	$	125,460,000	40% of EPC cost – typical.
Other costs			
Cost of land and development	$	28,228,500	Assuming 9% of CAPEX.
Fuel connection costs	$M	$20M +$1.5M/km	
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	24,100	Based on Aurecon internal database.
Variable O&M Cost	$ / MWh (Net)	7.6	Based on Aurecon internal database.
Total annual O&M Cost	$	8,520,000	Annual average cost over the design life

4.7 Open Cycle Gas Turbine

4.7.1 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.

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

4.7.2 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 i.e. 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 used in OCGT applications including for example instances where F class machines used in OCGT configuration in Australia (i.e. Mortlake Power Station (operational), Tallawarra B Power Station (under construction). and Kurri Kurri Power Station (entering construction)). Ultimately, the choice of gas turbine will depend on the many factors including the operating regimes of the plant, size, and more importantly, life cycle cost.

4.7.3 Recent trends

The increased installation of renewables has created opportunities for capacity firming solutions, that are currently largely met by gas-fired power generation options. OCGT and reciprocating engines compete in this market. There is a trend for gas turbine solutions to be planned to move towards low emissions solutions with either blending of or firing completely on hydrogen. All new gas turbine projects are expected to include provision/capability for hydrogen blending and eventual conversion to hydrogen firing.

With the exception of the 276 MW emergency power generation plant in South Australia, which included deployment of nine TM2500 aero-derivative gas turbines in 2017, the most recent OCGT installation on the NEM was Mortlake Power Station in 2011. This included two 283 MW F-Class gas turbines supplied by Siemens.

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

- 250 MW peaking/mid-merit OCGT in Newcastle. This project is currently planned for development. It is likely that if an OCGT solution, it would be multiple units of aero-derivative machines.
- 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) under construction, with 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. This project is currently entering construction phase

GT World's market forecast on gas turbine pricing quoted below reflects an increase in gas turbine prices.

"Rebounding from a 2-year downturn caused by falling oil prices and the global Covid-19 pandemic, 2021 was a good year for gas turbine sales, and GT World expect sales growth again in 2022. Measured on the basis of total Units sold, orders were up 8.5%, while MW order activity was down 12.5% from 2020. OEMs have reported price increases upwards of 10% driven by higher costs. On a capacity basis, gas turbines sized 150 MW or greater have dominated order activity over the past 5 years with units sized 300 MWs or more increasingly taking a larger share of the market. This trend reversed in 2021, with units ranging from 30 MW to 100 MW seeing increasing support as backup for renewable power. Looking ahead, GT World anticipate coal retirements in North America, Germany and China will mainly benefit large Heavy Frame gas turbines. Aero gas turbines, which provide backup capacity for renewable energy, will also benefit from higher demand and steady pricing. In the Electric Power Utility Sector: units in the 30-40 MW range are up and 300 MW+ units have rocketed"[15]

4.7.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical projects (one considering multiple smaller aero-derivative units and one considering a single large industrial unit) on natural gas fuel. The hypothetical projects have been selected based on what is envisaged as a plausible project for installation in the NEM in 2022, given the above discussion on typical options and current trends.

Table 4-17: Configuration and performance

Item	Unit	Small GTs	Large GT	Comment
Configuration				
Technology		Aero-derivative	Industrial (F-Class)	

[15] https://gasturbineworld.com/market-forecast

Item	Unit	Small GTs	Large GT	Comment
Make model		LM 6000 PF SPRINT	GE 9F.03	Small GTs − Typical model used in Australia Large GT − Smallest F-Class unit available
Unit size (nominal)	MW	49	265	ISO / nameplate rating, GT Pro.
Number of units		5	1	
Performance				
Total plant size (Gross)	MW	257.2	244.3	25°C, 110 metres, 60%RH
Auxiliary power consumption	%	1.7%	1.1%	Small GTs − Includes fuel compressor auxiliary power consumption Large GT − Assumes no fuel compression required
Total plant size (Net)	MW	252.9	241.7	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	235.3	226.4	35°C, 110 metres, 60%RH
Seasonal Rating – Not Summer (Net)	MW	267.2	258.2	15°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) LHV Net	11.458	14.735	25°C, 110 metres, 60%RH. Assuming a Minimum Stable Generation as stated below.
Heat rate at maximum operation	(GJ/MWh) LHV Net	9.049	9.766	25°C, 110 metres, 60%RH
Thermal Efficiency at MCR	%, LHV Net	39.79%	36.86%	25°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) HHV Net	12.684	16.312	Assuming LHV to HHV conversion ratio of 1.107.
Heat rate at maximum operation	(GJ/MWh) HHV Net	10.017	10.811	Assuming LHV to HHV conversion ratio of 1.107.
Thermal Efficiency at MCR	%, HHV Net	35.94%	33.30%	Assuming LHV to HHV conversion ratio of 1.107.
Annual Performance				
Average Planned Maintenance	Days / yr.	3	5	Assuming maintenance on all units completed concurrently
Equivalent forced outage rate	%	2%	2%	
Effective annual capacity factor (year 0)	%	20%	20%	Average capacity factor for similar GTs on the NEM. This can start from approximately 5%
Annual generation	MWh / yr.	443,117	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 4-18: Technical parameters and project timeline

Item	Unit	Small GTs	Large GT	Comment
Technical parameters				
Ramp Up Rate	MW/min	Up to 250	22	Station ramp rate (all units simultaneously) under standard operation. Based on OEM data.

Item	Unit	Small GTs	Large GT	Comment
Ramp Down Rate	MW/min	Up to 250	22	Station ramp rate (all units simultaneously) under standard operation. Based on OEM data.
Start-up time	Min	5	30	Standard operation.
Min Stable Generation	% of installed capacity	50%	50%	Assuming Dry Low NO_x burner technology.
Project timeline				
Time for development	Years	2	2	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2022	2022	
EPC programme	Years	2	2	For NTP to COD.
▪ Total Lead Time	Years	0.75	1	Time from NTP to gas turbine on site.
▪ Construction time	Weeks	65	58	Time from gas turbine on site to COD.
Economic Life (Design Life)	Years	25	25	Can be capacity factor dependant
Technical Life (Operational Life)	Years	40	40	

4.7.5 Cost estimate

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

Table 4-19: Cost estimates

Item	Unit	Small GTs	Large GT	Comment
CAPEX – EPC cost				
Relative cost	$ / kW	1,375	865	Net basis. Increase by 10-15% from 2021. Larger F class GTs such as those proposed at Kurri Kurri power station are expected to be ~5% higher on a $/kW basis. Switchyard excluded. Relative cost does not include land and development costs.
Total EPC cost	$	347,737,500	209,070,000	
▪ Equipment cost	$	243,416,250	146,349,000	70% of EPC cost – typical.
▪ Construction cost	$	104,321,250	62,721,000	30% of EPC cost – typical.
Other costs				
Cost of land and development	$	31,296,375	18,816,000	Assuming 9% of CAPEX.
Fuel connection costs	$M	$20M +$1.5M/km	$20M +$1.5M/km	Gas Transport (i.e. pipes/lines). Excludes consideration of line pack for storage.
Gas compressors	$	$2,500,000	Not required	
Gas storage[16]		Fixed: $0.015 - $0.025 /GJ/Day Variable (injection): $0.014 - $0.093 /GJ Variable (withdraw): $0.041 - $0.093 /GJ		Gas storage refers to underground storage facility in a depleted natural gas field. Costs based on published prises for Iona underground gas facility.

[16] ACCC (2020), "Gas inquiry 2017–2025 Interim report", www.ACCC.gov.au

Item	Unit	Small GTs	Large GT	Comment
First Year Assumed Commercially Viable for construction		2022	2022	
OPEX – Annual				
Fixed O&M Cost	$ / MW (Net)	12,600	10,200	Based on Aurecon internal database.
Variable O&M Cost	$ / MWh (Net)	12	7.3	Based on Aurecon internal database.
Total annual O&M Cost	$	8,503,944	5,556,904	Annual average cost over the design life

4.8 Combined Cycle Gas Turbine

4.8.1 Overview

Over time, combined-cycle gas turbines (CCGT) have become 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%.

4.8.2 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 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 e.g. 3 x 1 configuration, but they are not a typical offering.

4.8.3 Recent trends

In Australia, there has not been a CCGT plant constructed in the NEM region since the commissioning of Tallawarra 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, 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
- Tallawarra B CCGT plant from conversion using single F class OCGT plant

The choice of gas turbine class would be influenced by the project size. The demand in the NEM may not require a CCGT plant based on advanced high-efficiency gas turbines i.e. F or H class gas turbines. Unless the market demand conditions are known, 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 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 Class gas turbines however range from 445 – 595 MW in open-cycle, and from 660 – 840 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.

New future CCGT developments in Australia are currently not seen as probable, rather open cycle gas turbine units with capability for operation on hydrogen blended fuel with future provision to convert to CCGT considered but potentially not implemented, given latest trends in other firming and storage options in the market to accommodate the increase in renewable energy on the NEM.

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 2022 and beyond, given the above discussion on typical options and current trends.

Table 4-20: 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 HP temperature – 582°C Reheat temperature – 567°C
Performance					
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%	
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	

Item	Unit	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
Thermal Efficiency at MCR	%, LHV Net	56.4%	53.4%	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 4-21: Technical parameters and project timeline

Item	Unit	CCGT without CCS	CCGT with CCS	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.
Start-up time	Min	Cold: 145 Warm: 115 Hot: 30	Cold: 145 Warm: 115 Hot: 30	Cold: 145 Warm: 115 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	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2022	2022	2022	
EPC programme	Years	2.5	2.5	2.5	For NTP to COD.
▪ Total Lead Time	Years	1	1	1	Time from NTP to gas turbine on site. Steam turbine on site is a longer duration.
▪ Construction time	Weeks	78	78	78	Time from gas turbine on site to COD.

Item	Unit	CCGT without CCS	CCGT with CCS	CCGT with CCS (50% capture)	Comment
Economic Life (Design Life)	Years	25	25	25	
Technical Life (Operational Life)	Years	40	40	40	

4.8.5 Cost estimate

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

Table 4-22: Cost estimates

Item	Unit	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
CAPEX – EPC cost					
Relative cost	$ / kW	1620	3,995	2,965	Net basis, Increase of 8% of CCGT plant cost from 2021[17]. Relative cost does not include land and development costs.
Total EPC cost	$	601,020,000	1,275,420,000	1,002,450,000	
▪ Equipment cost	$	420,714,000	420,714,000	420,714,000	70% of EPC cost (without CCS)
▪ Construction cost	$	180,306,000	180,306,000	180,306,000	30% of EPC cost (without CCS)
▪ Carbon Capture cost	$	N/A	674,400,000	401,430,000	Equipment and installation
Other costs					
Cost of land and development		54,091,800	114,787,800	90,220,500	Assuming 9% of CAPEX.
Fuel connection costs (CAPEX)	$M	$20M +$1.5M/km	$20M +$1.5M/km	$20M +$1.5M/km	Excludes any line pack for storage
Gas compressors		Not required	Not required	Not required	
Gas storage[18]		Fixed: $0.015 - $0.025 /GJ/Day Variable (injection): $0.014 - $0.093 /GJ Variable (withdraw): $0.041 - $0.093 /GJ			Gas storage refers to underground storage facility in a depleted natural gas field. Costs based on published prises for Iona underground gas facility.
CO_2 storage cost	$/t$CO_2$	N/A	$12 - 25 /t$CO_2$	$12 - 25 /t$CO_2$	Based on Rubin, E.S., et al (2015)[19] and adjusted to match report basis

[17] Thermoflow software increase in CCGT plant EPC price of 8% in its latest release version in 2022.
[18] ACCC (2020), "Gas inquiry 2017–2025 Interim report", www.ACCC.gov.au
[19] 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	CCGT without CCS	CCGT with CCS (90% capture)	CCGT with CCS (50% capture)	Comment
CO_2 transport	$/t$CO_2$/km	N/A	$0.1/t$CO_2$/km	$0.1/t$CO_2$/km	Based on Rubin, E.S., et al (2015)[17] and adjusted to match report basis
OPEX – Annual					
Fixed O&M Cost	$ / MW (Net)	10,900	16,350	14,480	Based on Aurecon internal database.
Variable O&M Cost	$ / MWh (Net)	3.7	7.2	6.0	Based on Aurecon internal database.
Total annual O&M Cost	$	11,255,700	17,303,880	15,558,012	Annual average cost over the design life

4.9 Bioenergy

4.9.1 Scope for 2022 Report

Bioenergy considered in this report include:

- Biogas digesters
- Biomass generators using wood chips, pellets or prepared biomass feed – Need meeting to discuss technology (likely cogeneration/CHP)
- Biodiesel production using pathways suitable for Australian feedstocks with demonstrated technologies
- Waste to Energy plant using pathways suitable for Australian feedstocks with demonstrated technologies – Need meeting to discuss technology (likely cogeneration/CHP)

The past 12 months have seen considerable advances in the acceptance, adaption and integration of bioenergy systems into circular economy applications.

The following figure provides a infographic highlighting the circular economy nature for bioenergy systems.

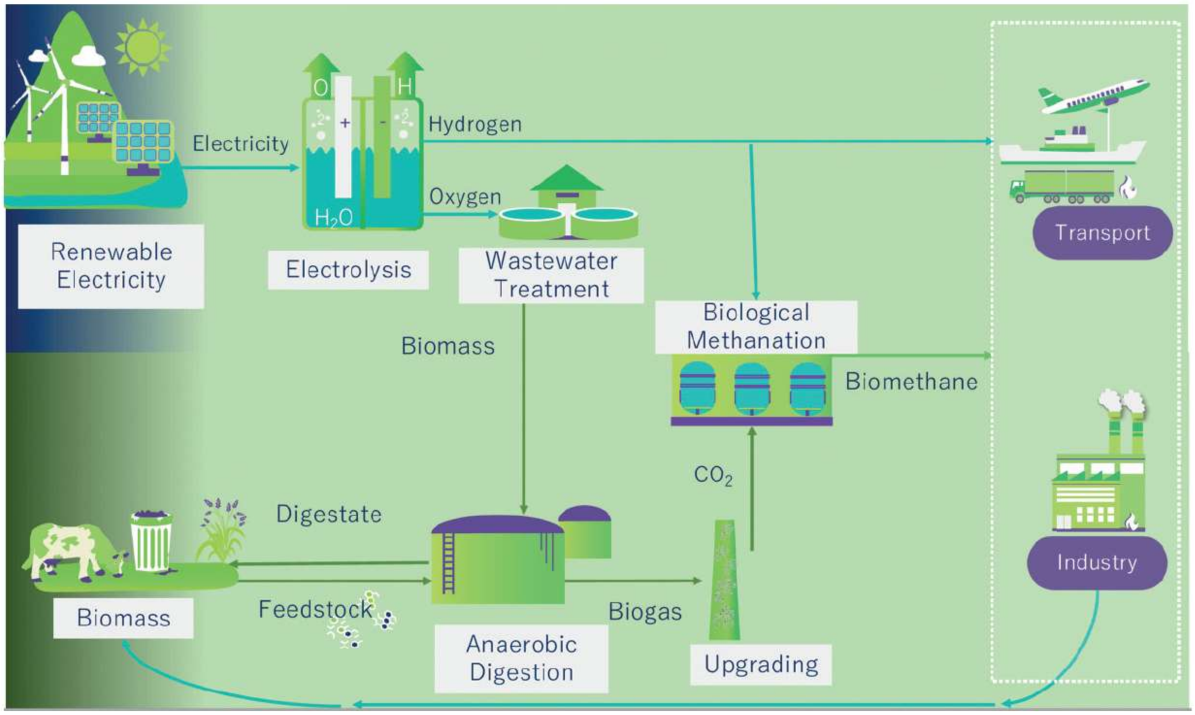

Figure 4-1: Bioenergy systems utilizing renewable feedstocks

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

4.9.2 Emerging sustainability issues

The current focus on ESG and SDG's 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).

4.9.3 Biogas systems

4.9.3.1 Biogas, biomethane and syngas

Biogas is a gas mixture containing methane (CH4) and CO2, along with water vapour and other trace gases. The composition of CH4 in biogas is typically in the range of 45 to 75% whilst CO2 comprises 30 to 50%. This variation means that the energy content of biogas can vary; the lower heating value (LHV) is between

16 megajoules per cubic metre (MJ/m3) 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.

Solid biomass can 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.

4.9.3.2 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.

4.9.3.3 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 bio-economy. 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.

4.9.3.4 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 CO2. 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 CO2 has not been utilized to date. Emerging systems are converting the CO2 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 CO2 are coming into focus.

4.9.3.5 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. facility was also strategically designed to run off of 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.

4.9.3.6 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.

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.

4.9.3.7 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, (i.e. 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 CO_2 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.

4.9.3.8 Current Australian Example Projects

Goulburn Bioenergy Project

Lead Organisation ReNu Energy Limited, Location Goulburn, New South Wales

Started May 2017, and completed on 23 October 2018.

$6.4m Total project cost

The Goulburn Bioenergy project is led by ReNu Energy responsible for a Bioenergy Project at the Southern Meats Facility in Goulburn NSW. This project built an anaerobic digester that captures biogas from the breakdown of effluent and organic waste from the Southern Meats abattoir. The gas is then fed into biogas generators to produce electricity for Southern Meats to operate their abattoir under a Power Purchase Agreement. The project has the capacity to displace 75% of peak load and has the ability to draw mains gas to further meet peak loads.

The anaerobic digester captured biogas from the breakdown of effluent and organic waste from the Southern Meats abattoir. The biogas was then fed into biogas generators and used to provide power to the abattoir. The project achieved significant energy savings and environmental benefits, with the capacity to displace 75% of peak load and the ability to draw mains gas to further meet peak loads.

The facility diverts 30,000 tonnes of commercial food waste and liquids from landfill to generate up to 20.3 million kWh of biomethane energy each year.

AJ Bush & Sons Boilers and Biogas Recovery Projects

Lead Organisation AJ Bush & Sons, Location Beaudesert, Queensland

Started 2018.

$3m 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 project also entailed a new solar PV PPA and an extension of the existing bioenergy PPA located at AJ Bush's rendering facility with ReNu Energy.

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.

Malabar Biomethane Injection Project

Lead Organisation Jemena Limited, Location Malabar, New South Wales

Started November 2020, and on-track to be fully operational by late 2022.

$16m Total project cost

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.

4.9.3.9 2022 Selected hypothetical project

This hypothetical project includes power generation from the biogas, 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.

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 2022 given the above discussion on typical options and current trends.

The assumed biogas project involves an assumed 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 4-23: 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 MW Electrical 2 MW Thermal	Assumed generation using 2 x 1,200 kW CHP co-generators
Number of units		1 biogas system 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/Nm³	4.5	
Performance			
Total plant size (Gross)	MW	2.2 Electrical 2.3 MW Thermal	Anaerobic digestion plant supplying biogas to 2 x 1.2 MW CHP co-generators
Biogas Production	NmÂ³/a	7,560,000	@ 55% Methane and 8400 hours
Methane Production	NmÂ³/a	4,158,000	@ 8400 hours
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	

Table 4-24: 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	2022	
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

4.9.3.10 Biogas hypothetical project cost estimates

Costs used in this 2022 Biogas hypothetical assessment have been aggregated from OEM quotes from recent projects and a nominal selection of associated infrastructure.

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 the cost parameters for the hypothetical Biogas project as outlined above.

Table 4-25: Cost estimates for the hypothetical Biogas project

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	$13,000	Net basis for 2000 kW. Relative cost does not include land and development costs.
Total Capital cost	$	$26,000,000	
▪ Equipment cost	$	$10,400,000	40% of EPC cost – typical.
▪ Installation cost	$	$15,600,000	60% of EPC cost – typical.
Other costs			
Cost of land and development	$	$2,600,000	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)	$400,000	Aggregated for scope listed above
Variable O&M Cost	$ / MWh (Net)	70	Assuming AD plant and CHP systems over 8400 hrs
Total annual O&M Cost	$	$1,850,000	For 2 MW over 8400 hrs

4.9.4 Biomass generators using wood waste

4.9.4.1 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.

4.9.4.2 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 (i.e. wood chips, sawdust, etc), harvest residues (i.e. 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.

4.9.4.3 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 660MW coal fired units of Drax Power Station in the UK, Atikokan Unit (205MW), Canada and Thunder Bay Generating Station in Ontario, Canada (163MW). Japan is currently undergoing a biomass-to-energy boom since the introduction of a feed-in-tariff (FIT) policy in 2012. 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 operational 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.

4.9.4.4 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 2022 given the above discussion on typical options and current trends.

Table 4-26: 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	
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	Assuming straight line degradation.
Annual degradation over design life – heat rate	%	0.2%	Assuming straight line degradation.

Table 4-27: 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 Warm: 120 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	2022	
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	

4.9.4.5 Cost estimate

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

Table 4-28: Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW (electrical energy basis) $ / kW (electrical and thermal energy basis)	7,178 2,772	Net basis (plant includes process heat as well). Relative cost does not include land and development costs.
Total EPC cost	$	199,567,000	Plant includes electrical as well as thermal energy as output (thermal energy is a bleed from steam turbine) Plant electrical cost component of total for reference ($169,200,031) - plant without thermal energy component Plant process heat cost component of total for reference ($30,266,969) - plant with electrical and thermal energy
4 Equipment cost	$	119,740,000	60% of EPC cost – typical.
5 Installation cost	$	79,827,000	40% of EPC cost – typical.
Other costs			

Item	Unit	Value	Comment
Cost of land and development	$	17,961,030	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.
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	151,014	AEMO costs and technical parameter review, 2018 (escalated)
Variable O&M Cost	$ / MWh (Net)	9.66	AEMO costs and technical parameter review, 2018 (escalated)
Total annual O&M Cost	$	6,311,185	

4.9.5 Biodiesel production

4.9.5.1 Overview

Biodiesel refers to a renewable, clean-burning fuel that is produced by transesterification of vegetable oils, used cooking oil, animal fat, etc. Some of the most commonly used plants for biodiesel production include soybeans and oil palm. Biodiesel is easy to use, non-toxic, biodegradable, and free of sulfur compounds and aromatics., and carbon-neutral, as compared to conventional sources of fuels. As a result, biodiesel finds diverse applications across several sectors, including automotive, marine, aviation, power generation, mining, etc. Moreover, biodiesel exhibits various lubricating properties that help in the lubrication of engines and add to engine life. As a result, it is also combined with petroleum diesel to be used in compression ignition engines. Biodiesel can be manufactured from a number of different feedstocks and processes.

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.

4.9.5.2 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)

4.9.5.3 Recent developments and 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). 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.

4.9.5.4 Renewable Diesel Developments

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 sulfur content, and a higher cetane value versus diesel fuel.

The following figure shows a typical renewable diesel production process:

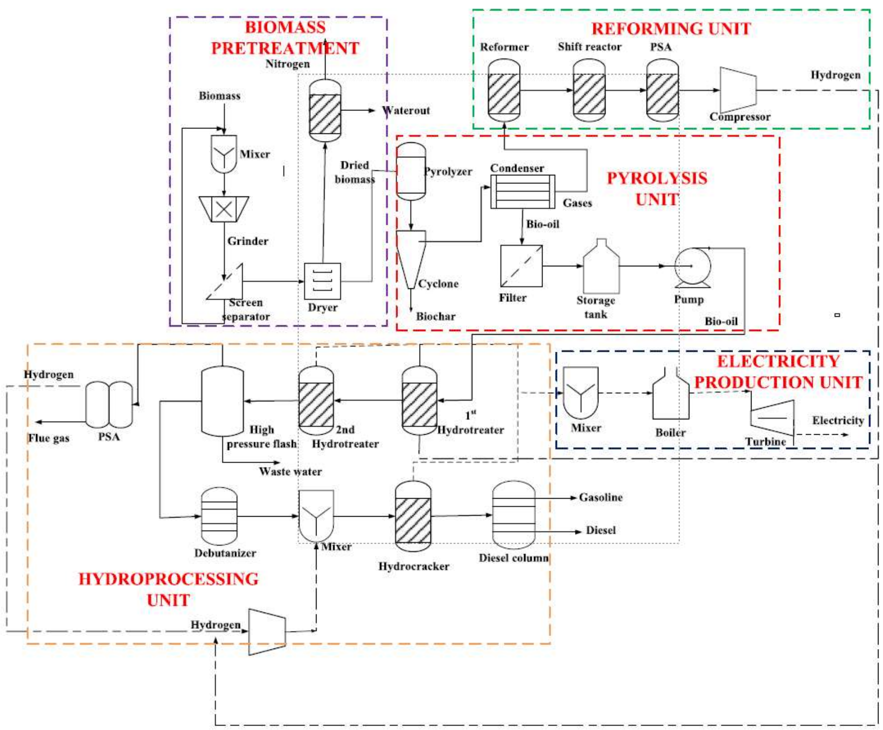

Figure 4-2: Schematic process diagram of fast pyrolysis and hydroprocessing technology

(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. Wilson said 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.

4.9.5.5 Recent trends on biodiesel cost of production

4.9.5.5.1 Australian Biodiesel Industry

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 CO_2 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 CO_2 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.

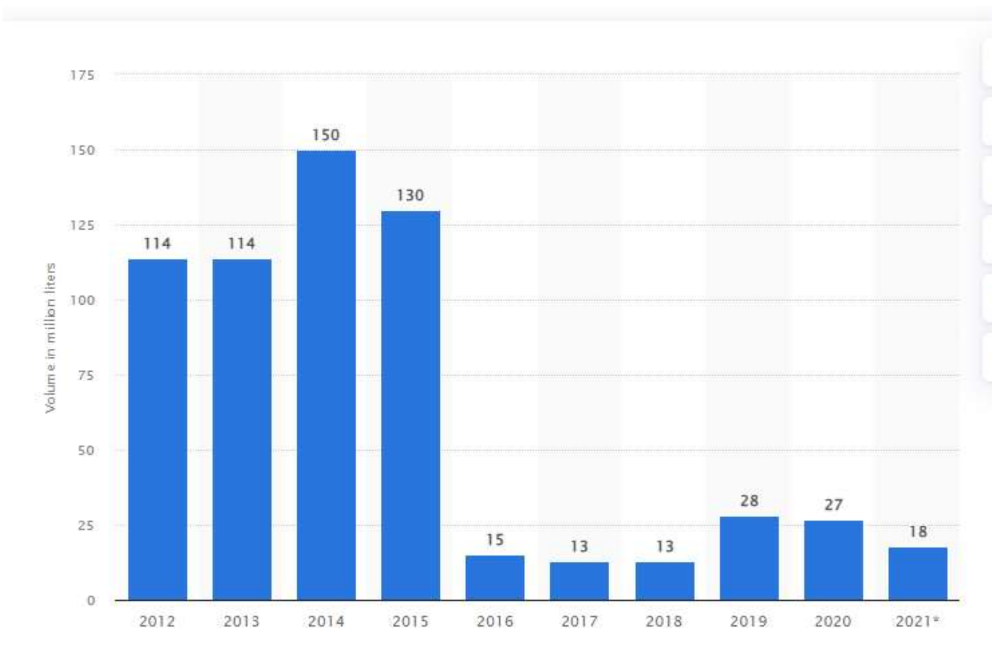

Figure 4-3: Production volume of biodiesel in Australia from 2012 to 2021

4.9.5.6 Current Australian example projects

4.9.5.6.1 Energy from Waste Through Pyrolysis Demonstration Plant

Lead Organisation Renergi

Location Collie, Western Australia

Started March 2020, and trials to continue to late 2022.

$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 (called 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. 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.

When completed, the plant will convert all combustible portions of municipal solid waste generated in Collie and about 8,000 tonnes of forestry waste per year into bio-oil and biochar. These are important value-added products that can replace fossil fuels and improve soil health and productivity. It is estimated that up to 18,000 tonnes of CO2-e will be avoided by the plant per year, equivalent to taking about 10,000 cars off the road.

4.9.5.6.2 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 shutdown 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.

4.9.5.6.3 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.

4.9.5.6.4 2022 Biodiesel hypothetical Project

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 the NEM in 2022given the above 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.

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

- Generation type - Renewable Biofuel Production
- Fuel types - Vegetable Oils from soybean, sunflower 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 $1.00 per litre of nameplate capacity.
- Other variable input costs of AUD 15 cents per litre of biodiesel.
- Total fixed costs of AUD 20 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 4-29: Biodiesel 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

Item	Unit	Value	Comment
Average Planned Maintenance/ Seasonal delays	Days / yr.	65	

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

Table 4-30: 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	2022	
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

4.9.5.6.5 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 COVID supply issues and the war in Ukraine, Global Biodiesel prices skyrocketed in the 2021 to 2022, reaching an all-time high (since 2007) of AUD $2.50. 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.

Costs used in this 2022 assessment assume a biodiesel production facility including an oilseed crush facility in the front end to produce vegetable oils. The costs have been aggregated from OEM quotes and a nominal selection of associated infrastructure, plus an allowance for escalation due to market conditions.

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

Table 4-31: Hypothetical biodiesel project cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Total Capital cost	$	$50,000,000	Total cost does not include land and development costs.
▪ Equipment cost	$	$20,000,000	40% of EPC cost – typical.

Item	Unit	Value	Comment
■ Installation cost	$	$30,000,000	60% of EPC cost – typical.
Other costs			
Cost of land and development	$	$5,000,000	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	$300,000	Aggregated for scope listed above
Variable O&M Cost	$ / ML	$900,000	Assuming current feedstock and energy prices
Total annual O&M Cost	$	$60,000,000	

4.10 Waste to Energy Plants

4.10.1 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.

4.10.2 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.

4.10.3 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.

4.10.4 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.

4.10.5 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 in Western Australia as listed below. However, there are also a number of other projects at various stages of development.

- Avertas Energy (Kwinana, WA): The plant is currently under construction and is expected to be commissioned in 2022. The plant will process approximately 400,000 tonnes of municipal waste per annum and generate about 36 MW of electricity. The plant is co-developed by Macquarie Capital and Phooenix energy at an estimated cost of $698 million. The project has received ARENA funding.
- East Rockingham (Perth, WA): This Clean Energy Finance Corporation and ARENA funded project is currently under construction. 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.

4.10.6 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 2022 given the above discussion on typical options and current trends.

Table 4-32: 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	

Item	Unit	Value	Comment
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	Assuming straight line degradation.
Annual degradation over design life – heat rate	%	0.2%	Assuming straight line degradation.

Table 4-33: 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 Warm: 120 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	2022	
EPC programme	Years	3	For NTP to COD.
1 Total Lead Time	Years	1.75	Time from NTP to steam turbine on site.
2 Construction time	Weeks	65	Time from steam turbine on site to COD.
Economic Life (Design Life)	Years	30	

Item	Unit	Value	Comment
Technical Life (Operational Life)	Years	50	

4.10.7 Cost estimate

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

Table 4-34: Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	20,675	Net basis. Relative cost does not include land and development costs.
Total EPC cost	$	545,820,000	
3 Equipment cost	$	327,492,000	60% of EPC cost – typical.
4 Installation cost	$	218,328,000	40% of EPC cost – typical.
Other costs			
Cost of land and development	$	49,123,800	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)	193,238	
Variable O&M Cost	$ / MWh (Net)	12.4	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 negotiated for the individual project.
Total annual O&M Cost	$	6,397,204	

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 2022 Excel spreadsheets, which are included in Appendix A.

5.2 Reciprocating engines

5.2.1 Overview and typical options

An overview of reciprocating engines and configuration, speed classifications, and fuel types covering gaseous (typically natural gas), liquid fuel, and dual fuel is discussed in Section 4.6.2 and Section 4.6.3.

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. It should be noted, however, that the national gas regulatory framework is currently only being reformed to include hydrogen blends with initial focus on consumption in existing natural gas appliances.[20]

5.2.2 Recent trends

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. These projects include:

- 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 has undertaken engine testing with 100% hydrogen based on its recent testing program with its one engine type product released in July 2021 to operate on 100% hydrogen, with its other engine types due to be 100% hydrogen ready for release in 2022[21]. Another OEM is offering a specifically configured engine model for 100% hydrogen use as demonstrator units for delivery in late 2022.[22] Other OEMs plan to be able to offer 100% hydrogen capability by 2025.

Hyosung Heavy Industries is developing the first pilot power plant project (1 MW) in APAC that will be fuelled by 100% hydrogen produced as a byproduct at a chemical plant expected to achieve commercial operation in 3Q 2022 and complete the demonstration by end of 2022.[23]

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[20] https://www.energy.gov.au/government-priorities/energy-ministers/priorities/gas/gas-regulatory-framework-hydrogen-renewable-gases

[21] https://www.innio.com/en/news-media/news/press-release/innio-jenbacher-gas-engines-ready-for-hydrogen

[22] https://www.cat.com/en_GB/news/engine-press-releases/caterpillar-to-offer-power-solutions-operating-on-100-hydrogen-to-customers-in-2021.html

[23] https://www.innio.com/en/news-media/press-releases/innio-technology-selected-for-first-100-hydrogen-engine-power-plant-in-asia-pacific

100% hydrogen reciprocating engines are expected to require a hydrogen gas train (instead of natural gas), intake manifold, fuel rail and port injection modifications.

5.2.3 Selected hypothetical project

Hydrogen supply will 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 of up to 10% and State government aspirations for 10% hydrogen blending in gas networks by 2030 this is likely to lead to reciprocating engine plants using a blend of hydrogen with natural gas.

Alternatively, a 100% hydrogen reciprocating engine plant could be supplied from a dedicated 10 MW electrolyser plant using renewable energy supply. This is the basis of the hypothetical project selected with engine size and plant capacity based on a 10 MW electrolyser plant for hydrogen production.

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged maybe a plausible project for development in the NEM in 2022 given the above discussion on typical options and current trends.

Table 5-1: Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology / OEM		INNIO Jenbacher	100% Hydrogen
Make model		JMS 420	
Unit size (nominal)	MW	2.25	Nameplate rating at generator terminals.
Number of units		3	
Performance			
Total plant size (Gross)	MW	6.75	25°C, 110 metres, 60%RH
Auxiliary power consumption	%	4%	
Total plant size (Net)	MW	6.48	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	6.48	Derating does not typically occur until temperatures over 35 – 40°C.
Seasonal Rating – Not Summer (Net)	MW	6.48	
Heat rate at maximum operation	(GJ/MWh) LHV Net	9.494	25°C, 110 metres, 60%RH
Thermal Efficiency at MCR	%, LHV Net	37.9%	25°C, 110 metres, 60%RH
Heat rate at maximum operation	(GJ/MWh) HHV Net	11.235	25°C, 110 metres, 60%RH
Thermal Efficiency at MCR	%, HHV Net	32.0	25°C, 110 metres, 60%RH
Hydrogen consumption at maximum operation	kg/h HHV	534	3 engines at MCR
Annual Performance			
Average Planned Maintenance	Days / yr.	2.7	Based on each engine only running 1752 hours per year.
Equivalent forced outage rate	%	2%	
Annual capacity factor	%	20%	Typical for current planned firming generation dispatch. Hydrogen storage required
Annual generation	MWh / yr.	11,353	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 5-2: Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp Up Rate	MW/min	2	Station ramp rate (all units) under standard operation. Based on OEM data.
Ramp Down Rate	MW/min	12.48	Station ramp rate (all units) under standard operation. Based on OEM data.
Start-up time	Min	6-10	Standard operation. Based on OEM data. Depending on whether hot or cold conditions
Min Stable Generation	% of installed capacity	40%	Assumed same as natural gas.
Project timeline			
Time for development	Years	2	includes pre/feasibility, design, approvals, procurement, etc.
First Year Assumed Commercially Viable for construction	Year	2022	
EPC programme	Years	2	For NTP to COD.
▪ Total Lead Time	Years	1	12 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 dependant
Technical Life (Operational Life)	Years	40	

5.2.4 Cost estimate

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

Table 5-3: Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	1,825	Net basis. 60% capex premium on engine only component for 100% hydrogen compared to natural gas only engine. Relative cost does not include land and development costs.
Total EPC cost	$	11,826,000	
▪ Equipment cost	$	7,095,600	60% of EPC cost – typical.
▪ Installation cost	$	4,730,400	40% of EPC cost – typical.
Other costs			
Cost of land and development	$	1,064,340	Assuming 9% of CAPEX.
Fuel connection costs	$M	Excluded	Assumes hydrogen storage provided separately
OPEX – Annual (excluding fuel)			
Fixed O&M Cost	$ / MW (Net)	33,000	Based on Aurecon internal database.
Variable O&M Cost	$ / MWh (Net)	-	Included above.
Total annual O&M Cost	$	213,840	Annual average cost over the design life

5.3 Gas turbines, including hydrogen conversion of gas turbines

5.3.1 Overview and typical options

An overview of configuration, technologies, and sizes for open cycle gas turbines is discussed in Section 4.7.1 and Section 4.7.3 considering natural gas and liquid fuel operation.

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.

Some are quite low (i.e. 5 - 15%) whilst others 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 next few years with newly designed micro/multi-nozzle combustion systems being developed and tested to cater for hydrogen.

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 respectively.

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, 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[24].

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 aeroderivative gas turbine units stated as capable of operation on 100% hydrogen with its wet combustion system (WLE)[25]

Kawasaki Heavy Industry (KHI) has recently 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[26].

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

[24] https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf
[25] https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/
[26] https://www.kawasaki-gasturbine.de/files/Hydrogen_as_fuel_for_GT.pdf

be required to meet local NOx emission limits depending on OEM, combustion system used (DLN or diffusion type), and hydrogen blending percentage.

5.3.2 Recent trends

The Tallawarra B OCGT project under construction includes a large 9F gas turbine and has a commitment to the NSW government to generate power using a 5% hydrogen blend with natural gas.

There are other projects in Australia that are investigation using a hydrogen blended fuel with natural gas for power generation based on current renewable hydrogen industry developments. These projects include:

- Snowy Hydro's 660 MW peaking OCGT plant near Kurri Kurri (NSW) comprising two F class gas turbine units. The project is planned to be hydrogen ready initially with gas turbine being capable to burn up to 10% hydrogen blend by volume with natural gas, with potential up to 30% with modifications, subject to fuel logistics[27]
- Renewable hydrogen produced for power generation in an existing 35 MW industrial gas turbine using a 5% hydrogen blend in natural gas (not NEM connected)
- H2U Eyre Peninsular Gateway Project, South Australia – 75 MW electrolyser with renewable hydrogen used for ammonia production among other uses including two small 100% hydrogen turbines[28] for peaking power
- Kogan Creek 200 MW peaking power station – the recently released Queensland Energy and Jobs Plan noted that the Queensland Government will invest in a new hydrogen-ready gas peaking power station[29]

5.3.3 Selected hypothetical project

Hydrogen supply will 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 up to 10% and State government aspirations for 10% hydrogen blending in gas networks by 2030 this is likely to lead to open cycle gas turbine plants using a blend of hydrogen with natural gas. This is likely to suit a larger gas turbine as their current capability for hydrogen operation is still below 100% hydrogen.

Alternatively, a 100% hydrogen gas turbine plant could be supplied from a dedicated 10 MW electrolyser plant using renewable energy supply. This is likely to be a small gas turbine due to hydrogen consumption requirements and the current status of 100% hydrogen capability residing with small gas turbines from OEMs. This is the basis of one of the hypothetical projects with plant capacity based on hydrogen production from a 10 MW electrolyser plant and operated as peaking duty due to matching hydrogen supply and with demand.

The following tables outline the technical parameters for the hypothetical projects (one small gas turbine using a 100% hydrogen and one large gas turbine using a 5-10% hydrogen blend). The hypothetical project has been selected based on what is envisaged maybe plausible projects for development in the NEM in 2022 given the above discussion on typical options and current trends.

Table 5-4: Hydrogen turbine configuration and performance

Item	Unit	Small GT	Large GT	Comment
Configuration				
Technology		Industrial	Industrial (F-Class)	

[27] https://www.snowyhydro.com.au/hunter-power-project
[28] https://www.fuelsandlubes.com/worlds-largest-green-ammonia-plant-in-south-australia-gets-boost/
[29] Queensland Energy and Jobs Plan (epw.qld.gov.au)

Item	Unit	Small GT	Large GT	Comment
Make model		NovaLT16 (Baker Hughes)	GE 9F.03	Small GTs − Typical model planned in Australian project, assumes standard combustor with water injection required for NOx emission control Large GT − Smallest F-Class unit available
Unit size (nominal)	MW	15.9	265	% Output derate for 100% hydrogen to be confirmed with OEM. No derate considered ISO / nameplate rating, GT Pro.
Number of units		1	1	
Performance				
Total plant size (Gross)	MW	14.6	244.3	25°C, 110 metres, 60%RH % Output derate for 100% hydrogen to be confirmed with OEM. No derate considered
Auxiliary power consumption	%	1.5%	1.1%	Small GTs – Assumes no fuel compression required Large GT − Assumes no fuel compression required
Total plant size (Net)	MW	14.32	241.7	25°C, 110 metres, 60%RH % Output derate for 100% hydrogen to be confirmed with OEM. No derate considered
Seasonal Rating – Summer (Net)	MW	13.18	226.4	35°C, 110 metres, 60%RH % Output derate for 100% hydrogen to be confirmed with OEM. No derate considered
Seasonal Rating – Not Summer (Net)	MW	15.62	258.2	15°C, 110 metres, 60%RH % Output derate for 100% hydrogen to be confirmed with OEM. No derate considered
Heat rate at minimum operation	(GJ/MWh) LHV Net	13,696	14.735	25°C, 110 metres, 60%RH. Assuming a Minimum Stable Generation as stated below. % heat rate derate for 100% hydrogen to be confirmed with OEM. No derate considered
Heat rate at maximum operation	(GJ/MWh) LHV Net	10,591	9.766	25°C, 110 metres, 60%RH % heat rate derate for 100% hydrogen to be confirmed with OEM. No derate considered
Thermal Efficiency at MCR	%, LHV Net	34.0%	36.86%	25°C, 110 metres, 60%RH % heat rate derate for 100% hydrogen to be confirmed with OEM. No derate considered
Hydrogen demand at maximum operation	kg/h (HHV)	1,068	276 (@ 5% by vol at 100% load)	
Heat rate at minimum operation	(GJ/MWh) HHV Net	16,202	16.312	Assuming hydrogen LHV to HHV conversion ratio of 1.183.
Heat rate at maximum operation	(GJ/MWh) HHV Net	12,529	10.811	Assuming hydrogen LHV to HHV conversion ratio of 1.183.
Thermal Efficiency at MCR	%, HHV Net	28.7%	33.30%	Assuming hydrogen LHV to HHV conversion ratio of 1.183.
Annual Performance				

Item	Unit	Small GT	Large GT	Comment
Average Planned Maintenance	Days / yr.	5	5	
Equivalent forced outage rate	%	2%	2%	
Effective annual capacity factor (year 0)	%	10%	20%	Small GT – based on available hydrogen production. H2 storage required Average capacity factor for similar GTs on the NEM.
Annual generation	MWh / yr.	12,544	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 5-5: Hydrogen turbine technical parameters

Item	Unit	Small GTs	Large GT	Comment
Technical parameters				
Ramp Up Rate	MW/min	10	22	Station normal ramp rate under standard operation. Based on OEM data.
Ramp Down Rate	MW/min	10	22	Station normal ramp rate under standard operation. Based on OEM data.
Start-up time	Min	15	30	Standard normal operation.
Min Stable Generation	% of installed capacity	50%	50%	Small GT – to be confirmed with OEM for NOx emissions limits
Project timeline				
Time for development	Years	2.5	2	Small GTs project – additional time for any product testing Large GT – assumes hydrogen blend is within existing combustion system design capability includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2022	2022	
EPC programme	Years	2	2	NTP to COD.
▪ Total Lead Time	Years	0.75	1	Time from NTP to gas turbine on site.
▪ Construction time	Weeks	65	58	Time from gas turbine on site to COD.
Economic Life (Design Life)	Years	25	25	Can be capacity factor dependant
Technical Life (Operational Life)	Years	40	40	

5.3.4 Cost estimate

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

Table 5-6: Hydrogen turbine cost estimate

Item	Unit	Small GT	Large GT	Comment
CAPEX – EPC cost				
Relative cost	$ / kW	2,150	865	100% hydrogen for small GT 5-10% hydrogen blend in natural gas for large GT. Switchyard excluded. Relative cost does not include land and development costs.
Total EPC cost	$	30,788,000	209,070,000	
■ Equipment cost	$	21,551,600	146,349,000	70% of EPC cost – typical. 35% premium considered on small GT only cost for 100% hydrogen assumed. This does not include any SCR if NOx emissions limits are not met. NOx emissions with water injection on 100% hydrogen to be confirmed with OEM. 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	$	9,236,400	62,721,000	30% of EPC cost – typical.
Other costs				
Cost of land and development	$	2,770,920	18,816,000	Assuming 9% of CAPEX.
Fuel connection costs	$M	Excluded	$20M +$1.5M/km	Small GT plant assumed hydrogen supply from electrolyser plant available Large gas turbine plant - Gas Transport (i.e. 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	$	Not required	Not required	Assume hydrogen storage pressure sufficient; or gas pipeline supply pressure sufficient. Let down station may be required (not included)

Item	Unit	Small GT	Large GT	Comment
Gas storage[30]		cluded	Fixed: $0.015 - $0.025 /GJ/Day Variable (injection): $0.014 - $0.093 /GJ riable (withdraw): $0.041 - $0.093 /GJ	For Small GT plant assumes hydrogen storage cost considered elsewhere Gas storage refers to underground storage facility in a depleted natural gas field. Costs based on published prises for Iona underground gas facility.
First Year Assumed Commercially Viable for construction		)22	)22	For % hydrogen capability stated above. 100% hydrogen turbine testing timeline for small gas turbine to be confirmed with OEM for this development timeline.
OPEX – Annual (excluding fuel)				
Fixed O&M Cost	$ / MW (Net)	65,000	10,200	Based on Aurecon internal database.
Variable O&M Cost	$ / MWh (Net)	38	7.3	Based on Aurecon internal database. Small GT water consumption for NOx control not included (rate to be confirmed with OEM for NOx emissions control)
Total annual O&M Cost	$	1,407,492	5,556,904	Annual average cost over the design life

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, approximately 96% 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

[30] ACCC (2020), "Gas inquiry 2017–2025 Interim report", www.ACCC.gov.au

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 kW up to 20 MW. In larger facilities a number of modules will be required to meet the demand with an element of shared utilities.

5.4.3 Recent trends

The debate continues between the relative benefits of the various technologies and indeed 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[31], recently 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[32].

The world's largest PEM electrolyser in operation at 20 MW is installed at the Air Liquide hydrogen production facility in Bécancour, Quebec[33].

Globally the trend in electrolysis is to the larger scale with more and more projects planned to be developed in the triple figure MW range. Electrolyser OEMs are either planning to or are building giga-factories for the increased manufacturing production of electrolyser capacity requirements expected globally. A 200 MW electrolyser order has been reported to have been secured by Nel for a US industrial project with manufacturing completed in mid 2024.[34] The first ever GW scale electrolyser order (1 GW) with Plug Power has been reported with offshore wind powered green hydrogen project in Denmark with first hydrogen production planned in 2025[35]

For hydrogen production, PEM electrolysers have been growing 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.

Some leading proposed and planned hydrogen production projects under development at various stages in Australia in the 10 – 100 MW range using either PEM or Alkaline electrolysers yet to receive financial close, include:

- Neoen Hydrogen Superhub Project in Crystal Brook, South Australia
- H2U Eyre Peninsular Gateway Project, South Australia – 75 MW electrolyser with renewable hydrogen used for ammonia production among other uses
- Engie Yara Pilbara Renewable Ammonia Project – 10 MW electrolyser for renewable hydrogen production to be used in existing ammonia plant for ammonia production (announced financial investment decision in September 2022)[36]
- AGIG Hydrogen Park Murray Valley (HyP Murray Valley) Project – 10 MW electrolyser for renewable hydrogen production and use including blending with natural gas in local gas networks

[31] https://www.fch.europa.eu/news/launch-refhyne-worlds-largest-electrolysis-plant-rhineland-refinery
[32] 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
[33] 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
[34] https://www.rechargenews.com/energy-transition/largest-ever-order-nel-to-supply-200mw-of-hydrogen-electrolysers-to-mystery-us-buyer-in-45m-deal/2-1-1262427
[35] https://www.rechargenews.com/energy-transition/first-ever-gigawatt-scale-electrolyser-order-confirmed-for-offshore-wind-powered-green-hydrogen-project/2-1-1220683
[36] https://research.csiro.au/hyresource/yuri-renewable-hydrogen-to-ammonia-project/

- ATCO Clean Energy Innovation Park – 10 MW electrolyser for renewable hydrogen production and use including blending in gas network

Other recent larger scale planned developments (100 MW+) to be operational at the earliest in 2025, 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 and announced entering into FEED stage)
- Origin Energy's Bell Bay (GRAPE) Green Hydrogen Project with ammonia export, Tasmania
- ABEL Energy Bell Bay Powerfuels Project, Tasmania (100 MW)
- Eco Energy World Queensland Project (200 MW)
- Stanwell Iwatani's Central Queensland Hydrogen Project (up to 3 GWs of ultimate capacity)
- H2-Hub Gladstone Queensland (up to 3 GW in stages)

The Australian Government has also announced the development of up to seven clean hydrogen industrial hubs in regions of Australia, as well as design and development studies as part of its Australian Clean Hydrogen Industrial Hubs Project[37] with this funding program setup to support hub locations progressing to their next stage of project lifecycle. Hub implementation grants recently provided under the Clean Hydrogen Industrial Hubs Program include the following hub locations:

- Western Australian Government's Pilbara Hydrogen Hub, WA
- BP Australia's H2Kwinana Clean Hydrogen Industrial Hub, WA (at least 75 MW electrolyser)
- Stanwell Corporation's Central Queensland Hydrogen Hub (CQ-H2 Hub), QLD
- Port of Newcastle's Port of Newcastle Hydrogen Hub, NSW (initially 40 MW electrolyser)
- Origin Energy's Hunter Valley H2 Hub, NSW (55 MW electrolyser)
- South Australian Government's Port Bonython Hydrogen Hub, SA
- Tasmanian Government's Tasmanian Green Hydrogen Hub

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 with both expected to undergo dramatic reductions in cost (on a $/MW basis) as projects and manufacturing is being increased in scale. Electrolyser plant equipment capex from Chinese Alkaline suppliers can be up to 50% cheaper when compared to Western suppliers based on recent market activity on renewable hydrogen development projects in Australia.

Although PEM is seen as more responsive and/or flexible, recent 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). Requirement for responsiveness benefit should be assessed against the electrolyser application (eg FCAS services).

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 commercial project for installation in the NEM, given the above discussion on typical options and current trends based on the 2022 status for this report. Larger scale projects planned to be operational in 2025 and beyond pending commercial feasibility being realised and financial investment decision should be reviewed for inclusion as a plausible commercial hypothetical project in Australia in next year's report.

Table 5-7: Electrolyser configuration and performance

[37] https://research.csiro.au/hyresource/australian-clean-hydrogen-industrial-hubs-program/

Item	Unit	PEM	Alkaline	Comment
Configuration				
Technology		Proton Exchange Membrane	Alkaline	
Unit size (nominal)	MW	10	10	Selected based on the range of currently available single stack sizes (or combined as stack modules) and current potentially plausible commercial project with government funding support for installation in the NEM
Number of modules		1	1	
Performance				
Total plant size	MW	10	10	Net of auxiliaries
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
Hydrogen Production	kWh/kg	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	Siemens SILYZER 300 product (which is PEM) is offered as atmospheric
Additional compression power	kW	125	485	Additional power required to compress hydrogen to 100bar
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/kgH$_2$	–15-20	15 - 20	Typical raw water consumption volumes, for hydrogen production only (based on air cooled system). 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	Typical published value.

Table 5-8: 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 (e.g. 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 e.g. 20% per 6 sec)
Start-up time	Min	Cold: 5 Warm: 0.5	Cold: 60 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%	Typical
Project timeline				
Time for development	Years	2.5	2.5	Includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2022	2022	Although theoretically viable at this size in 2022 it is questionable that a hydrogen offtake agreement could be secured for this volume and at a price that would result in a commercially viable project with government funding support (the market will determine this).
EPC programme	Years	2	2	For NTP to COD.
▪ 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, however the costs are representative of the technology type rather than the specific vendors and models as per above.

Table 5-9: Cost estimates

Item	Unit	PEM	Alkaline	Comment
CAPEX – EPC cost				
Relative cost	$ / kW	3,250	2,000	Full EPC turn-key. Relative cost does not include land and development costs. Alkaline range ($1,500-$2,250/kW); PEM range ($2,750-$3,750/kW), varies based on Chinese supply vs Western supply and OEM. Chinese supply PEM not included in cost range. Lower costs for Chinese supply have been reported. The 2022 cost has been reviewed considering same size electrolyser as 2021 report taking into account recent market supply pricing in Australia and is reflected in increased pricing from 2021. Two key drivers for cost reduction include size of electrolyser plant and manufacturing volume towards GW scale facilities[38]. Refer below to discussion on Electrolyser plant cost for a larger size electrolyser plant considering these drivers to establish an associated cost projection in 2022 for a larger electrolyser size plant (20-30 MW).
Total EPC cost	$	32,500,000	20,000,000	
▪ Equipment cost	$	22,750,000	14,000,000	70% of EPC cost – typical. Excludes compression and storage
▪ Construction cost	$	9,750,000	6,000,000	30% of EPC cost – typical.
Other costs				
Cost of land and development	$	2,600,000	2,000,000	Based on 8-10% of CAPEX.
Fuel connection costs	$	N/A	N/A	
Hydrogen compressor	$	2,200,000	5,200,000	Single 1 x 100% duty train
Hydrogen transport	$/km	$150,000/km	$150,000/km	DN50 buried pipeline (suitable for 1 x 10 MW unit)
OPEX – Annual				
Fixed O&M Cost	$ / MW (Net)	97,500	60,000	Based on 3% of CAPEX per annum. Note that this includes allowance for the 10 year stack overhaul. Stack overhaul cost is based on current costs. Excludes power consumption costs
Variable O&M Cost	$ / MWh (Net)	-		Included in fixed O&M component.
Total annual O&M Cost	$	975,000	600,000	Annual average cost over the design life. Excludes power and water consumption costs.

[38] https://www.irena.org/publications/2020/Dec/Green-hydrogen-cost-reduction

The IEA Global Hydrogen Review Report 2021[39] indicates the potential reduction of Electrolyser plant capital costs over time from 2020 to 2050 considering alkaline and PEM technology and various carbon reduction scenarios based on a current global electrolyser Projects scenario to project requirements for a net zero emissions scenario. The capex reduction curve considers learning effects from manufacturing and economies of scale with electrolyser project sizes expected to increase over time. In 2022, there are reported to be a small number of projects planned to be in operation with larger electrolyser capacity plants mostly around 20-30 MW size based on IEA's Hydrogen Project Database. Application of this Electrolyser plant capex reduction curve for the current global electrolyser Projects scenario to the AEMO 2022 report Australian project figures in Table 5-9 on a percentage reduction basis suggests projected EPC Capex costs in 2022 for a nominal 20-30 MW electrolyser plant size as presented in Table 5-10. However, it should be noted that the gradient of this cost reduction curve seems optimistic for size based on current trends and as such is to be confirmed with market pricing.

Table 5-10: Projected EPC cost for 20-30 MW electrolyser plant, 2022

Item	Unit	PEM	Alkaline	Comment
CAPEX – EPC cost (projected for 20-30 MW electrolyser plant), 2022				
Relative cost	$ / kW	2,500	1,650	**Full EPC turn-key. Alkaline range ($1,250-$1,900/kW); PEM range ($2,150-$2,950/kW), varies based on Chinese supply vs Western supply and OEM. Chinese supply PEM not included in cost range. Lower costs for Chinese supply have been reported.** Table 5-9Reduction to 2022 cost figure in Table 5-9 at 10 MW size for increased size to 20-30 MW based on projected capex reduction curve in IEA Global Hydrogen Review Report 2021 .

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 continuous electricity generation.

[39] https://iea.blob.core.windows.net/assets/5bd46d7b-906a-4429-abda-e9c507a62341/GlobalHydrogenReview2021.pdf

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 installations supporting back-up power for homes, businesses, remote communities, universities, data-centres, and hospitals.

5.5.2 Typical options

Below are some of the most commonly used fuel cells[40]:

- 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.
- 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 <1 kW to 3 MW. Fuel cell installations being developed are offered as a containerised modular solution and can either be provided as standalone plants or installed in in combination with other power (e.g. Rooftop PV) or energy storage (e.g. 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[41]. Some of the largest technology companies including Apple, Google, IBM, Verizon, AT&T, and Yahoo have all recently installed small scale (kW scale) stationery hydrogen fuel cells as a source of power for their operations.

In 2020, Hanwha Energy commissioned the largest industrial hydrogen-fuel-cell power plant in the world, 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[42]

NREL is collaborating 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 due to be commissioning in late 2022[43].

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 recently installed at Ferrari's manufacturing facility in Italy offering fuel supply type flexibility required to power the plant[44].

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[45]

[40] http://www.fchea.org/fuelcells
[41] The Future of Hydrogen, Report prepared by the IEA for the G20, Japan, Seizing today's opportunities
[42] https://www.powermag.com/large-scale-hydrogen-projects-take-shape-as-technology-continues-to-evolve/
[43] https://www.nrel.gov/news/program/2022/new-research-collaboration-to-advance-megawatt-scale-hydrogen-fuel-cell-systems.html
[44] https://www.ferrari.com/en-EN/corporate/articles/a-1-mw-fuel-cell-plant-at-ferraris-maranello-facilities
[45] https://new.gbca.org.au/showcase/projects/sir-samuel-griffith-centre/

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[46] MW scale fuel cell power generation applications have started to be studied in Australia using renewable hydrogen production and storage for power generation and export during peak times and potential grid stability services.

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 2020, given the above discussion on typical options and current trends.

Table 5-11: 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	7.56	75.6	
Annual Performance				
Average Planned Maintenance	Days / yr.	-	-	Included in EFOR below.
Equivalent forced outage rate	%	2%	2%	

Table 5-12: Technical parameters and project timeline

[46] https://energys.com.au/green-hydrogen-news/toyota-launches-victorian-hydrogen-production-and-re-fuelling-facility-powered-by-energys-australia

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 Warm: 0.5	Cold: 5 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	2022	2022	
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 5-13: Cost estimates

Item	Unit	Small	Large	Comment
CAPEX – EPC cost				
Relative cost	$ / kW	13,300	6,100	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.
Total EPC cost	$	1,596,000	7,320,000	
▪ Equipment cost	$	1,276,000	5,856,000	80% of EPC cost – typical.
▪ Construction cost	$	320,000	1,464,000	20% of EPC cost – typical.
Other costs				
Cost of land and development		320,000	732,000	Assuming 10-20% of CAPEX due to overall small footprint.
Fuel connection costs	$	Excluded		Pressure let-down equipment may be required depending on hydrogen supply pressure.
OPEX – Annual				

Item	Unit	Small	Large	Comment
Fixed O&M Cost	$ / MW (Net)	532,000	244,000	Based on 5% of equipment CAPEX per year.[47]
Variable O&M Cost	$ / MWh (Net)	-	-	Included in the fixed O&M component.
Total annual O&M Cost	$	63,800	292,800	Annual average cost over the design life. Dependant of annual capacity factor. Excludes stack replacement. Includes scheduled maintenance and operator allowance.

5.6 SMR & 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 byproduct. SMR plants currently produce 95% of the world's hydrogen.[48]

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

The SMR process produces 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.

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).[49]

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,[50] though this efficiency should already be incorporated into

[47] 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
[48] 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
[49] De Vos 2021, Australian hydrogen market study, https://www.cefc.com.au/media/nhnhwlxu/australian-hydrogen-market-study.pdf
[50] https://www.topsoe.com/products/equipment/convection-reformer-htcr?hsLang=en

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 - $14 /t CO_2 for short transport distances to a high value of $70/t CO_2 for long transport distances.[51]

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 5-14: 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
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 $30/t CO_2.[52]

Table 5-15: SMR plant Cost estimate

Item	Low	High	Comment
Hydrogen production rate	200 tonne/d	900 tonne/d	
Cost of production	AUD $2.10/kg H_2	AUD $3.10/kg H2	reported in Zapantis 2020.[53] Note- the low and high cost figures refer to range of costs not plant size, larger plants are normally more efficient
CAPEX	AUD $1,300/kW H_2		(with no carbon capture)
CAPEX	AUD $1,820/kW H_2	AUD 2,400/kW H_2	(with carbon capture)[54]

[51] Electric Power Research Institute, 2015 Australian Power Generation Technology report
[52] Electric Power Research Institute, 2015 Australian Power Generation Technology report fig 138
[53] Zapantis 2020- Replacing 10% of NSW Natural Gas Supply with Clean Hydrogen: Comparison of Hydrogen Production Options
[54] IEA (2019), The Future of Hydrogen, Assumptions annex, IEA, Paris https://www.iea.org/reports/the-future-of-hydrogen

Item	Low	High	Comment
Total Capex Cost	600 M AUD	2700 M AUD	Total CAPEX with CCS
OPEX / year	18 M AUD	81 M AUD	

Based on the CAPEX data listed in Table 5-13, an SMR plant of 900 tonne H_2/day capacity would cost of the order of AUD $2B without carbon capture and $2.7B 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 (e.g. 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 700bar are possible, most compressed storage is less than 200 bar, owing to operating and safety concerns.[55] These are of varying size. These may range from a small 49L gas cylinder containing 0.65 kg Hydrogen at 164 Bar to large industrial vessels. [56] Hydrogen pressure 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, 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.[57]
- 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.[9]
- 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 and are not considered in this report. 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

[55] Anderson and Gronkvist, 2019. Large-scale storage of hydrogen, International Journal of Hydrogen Energy, (44) pp. 11901-11919
[56] Lee's Loss Prevention in the Process Industries, Chapter 22.14
[57] Rivard et al 2019- Hydrogen Storage for Mobility: A Review Materials, 12, 1973; doi:10.3390/ma12121973

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.[58]

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.[59] Plans are under way to build a plant with 90 tpd capacity.[60]

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.[61] The same company has also announced the design of 10,000m^3 storage facility for liquid hydrogen, but this has yet to be built.[62]

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.[63]

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.[64]

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.

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[58] Rivard et al 2019- Hydrogen Storage for Mobility: A Review Materials, 12, 1973; doi:10.3390/ma12121973
[59] Decker 2019- Latest Global Trend in Liquid Hydrogen Production
[60] Hydrogen Liquefiers | Air Liquide (engineering-airliquide.com)
[61] Be water: Japan's big, lonely bet on hydrogen - Nikkei Asia
[62] Kawasaki Completes Basic Design for World's Largest Class (11,200-cubic-meter) Spherical Liquefied Hydrogen Storage Tank | Kawasaki Heavy Industries, Ltd.
[63] Anderson and Gronkvist, 2019. Large-scale storage of hydrogen, International Journal of Hydrogen Energy, (44) pp. 11901-11919
[64] Innovative Liquid Hydrogen Storage to Support Space Launch System | NASA

Table 5-16: 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.[65]
Electricity Usage	12	kWh / kg H_2	Medium value from Connelly et al, 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 5-17: Liquid hydrogen storage hypothetical project Cost parameters

Item	Value	Units	Comment
Cost of Liquefaction and storage Plant Capex	183	$M AUD	From Connelly et al[51]
OPEX costs ($ / kg H2)	1.93	$ AUD /kg H_2	OPEX costs with CAPEX Component removed from US Study
OPEX / Year	19	$M AUD /yr	
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 is 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 be 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.[66]

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.

[65] Connelly et al 2019 - Current Status of Hydrogen Liquefaction Costs
[66] Melaina et al 2013, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues https://www.nrel.gov/docs/fy13osti/51995.pdf

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.[67]

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.[68] 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.

Table 5-18: 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[69]
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-[70] 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	400		$AUD /m	Based upon a South Australian project
Pipeline Cost		75,000	$AUD /km/inch	Based upon Aurecon in house data
Network Cost	480	189	$M AUD	

Transport of hydrogen produced from a hypothetical 10 MW electrolyser plant is assumed to be via a pipeline with assumptions as stated in Section 3.2.5.

[67]APA set to unlock australia's first hydrogen-ready transmission pipeline https://www.apa.com.au/news/media-statements/2021/apa-set-to-unlock-australias-first-hydrogen-ready-transmission-pipeline/
[68] US Department of Energy Hydrogen Pipelines | Department of Energy
[69] Zapantis 2020- Replacing 10% of NSW Natural Gas Supply with Clean Hydrogen: Comparison of Hydrogen Production Options
[70] IEA G20 Hydrogen report: Assumptions Annex

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 5-19: Geological Storage Technology Comparison

Parameter	Salt cavern	Depleted reservoir	Aquifer
Technology Readiness Level (TRL)	8	6	5
Capital Cost	Middle	Lowest	Highest
Operating Cost	Highest (Up to 10 gas cycles per year)	Lowest (Up to 2 cycles per year)	Lowest (Up to 2 cycles per year)
Technical Considerations	▪ Large volume of water required for cavern leaching ▪ Brine disposal following cavern leaching	▪ Impurities resulting in production of methane, H_2S ▪ Reactivity of hydrogen with liquid remaining liquid hydrocarbons	▪ Risk of gas leakage (aquifer tightness) ▪ 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

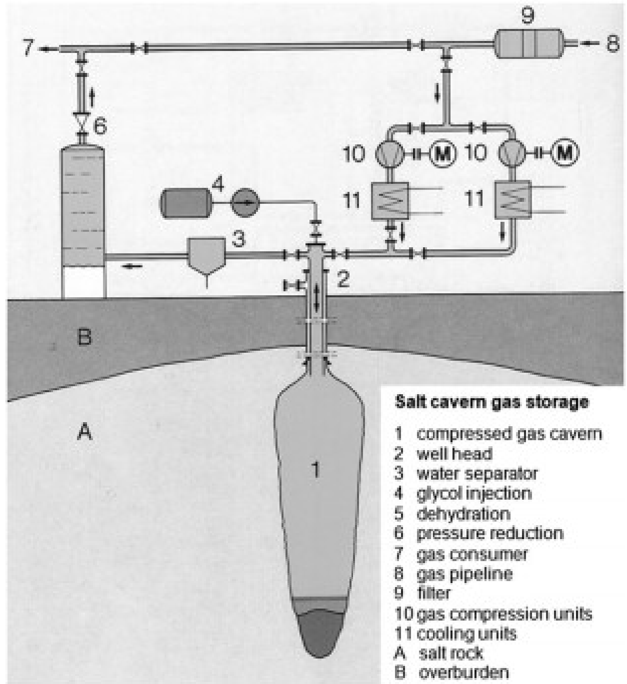

Figure 5-2: Salt cavern storage schematic (Ozarslan, 2012)

5.8.2 Recent trends

There are currently only four locations in the world which operate GHS at >95% purity of hydrogen. Table 5-20. provides a summary of major operating sites.

Table 5-20: 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. There is potential for increased competition with CCS projects if hydrogen storage in reservoirs is deemed viable in Australia.

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).

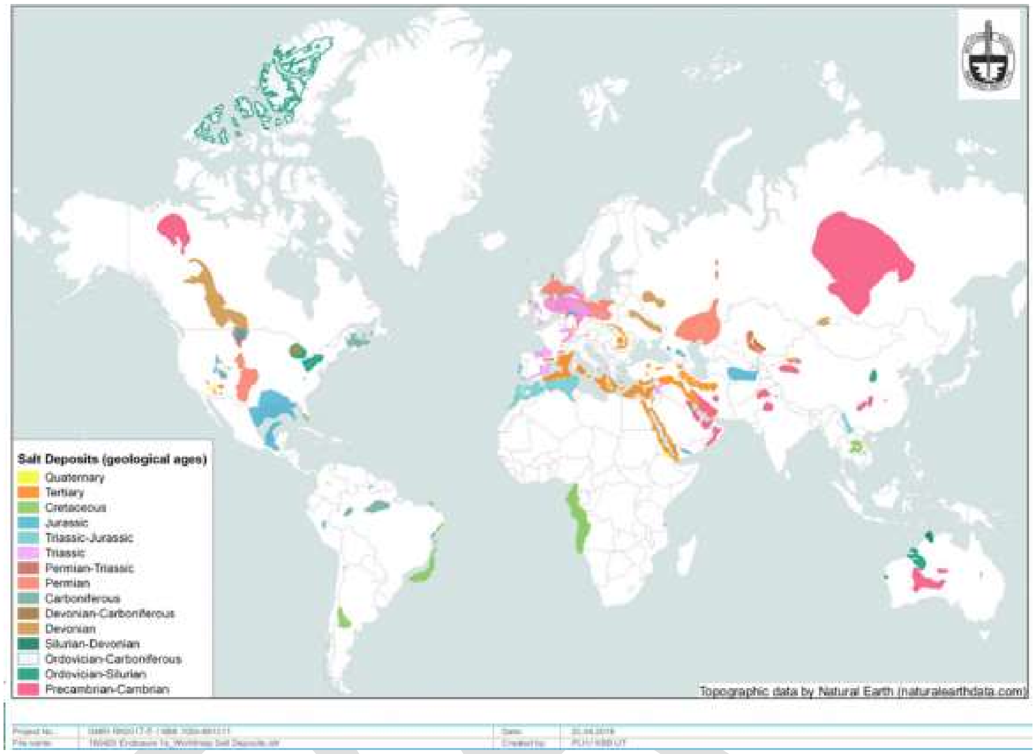

Figure 5-3: Global salt deposit locations (Engie, 2019).

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 5-21: 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

Item	Unit	Value	Comments
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 5-22: 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	35-55	Cavern and tunnel excavation, leaching
Leaching and Brine Disposal	$M AUD	5-10	Assumes $2 per barrel for brine disposal
Above Ground Costs	$M AUD	15-35	Includes compression, treatment and let-down kit, as well as piping
OPEX			
Operations and Maintenance	$M AUD per year	1.1 -1.98	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.

Ammonia's dominant use in terms of volume is to manufacture artificial fertilisers and explosives but is commonly used 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 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% 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 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, instead renewable energy and water are used the resulting ammonia can be referred to as being 'green'.

Traditional plants range from approximately 250 tonnes per day up to over 3,000 tonnes per day.

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 have a lower specific capex (cost per annualised unit output). Given the significant emission associated with ammonia production, both producers and technology providers are look 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 syntheses 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, as a result of the variable renewable energy source. 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.

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 use is becoming more feasible. As such reduced transport and storage costs 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 2021 given the above discussion on typical options and current trends.

Due to its size this plant will be classified as a Major Hazardous Facility (MHF).

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	$MWh/t(NH_3)$	1.0-1.5	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, not inclusive of fuel demands for heating, etc.
Water Consumption	$m^3/t(NH_3)$	0.2-0.8	Varies depending on cooling method and heat integration
Annual Performance			
Annual Ammonia output (typical)	tpa	350,000	Based on 350 online days per year (approximately 96%)
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	40-60	Turndown capability varies across technology providers

Item	Unit	Value	Comments
Synthesis Loop Pressure	bar	150-200	Synthesis pool pressure is unique to the technology providers equipment and catalyst.
Catalyst		Iron based	Specifics around catalyst vary from vendor to vendor
Footprint		100m x100m	
Project Timeline			
Project Development	months	12-18	From concept to FID
Project Execution	months	18-30	From FID to commissioning
Economic Life (Design 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	350 - 400	Excludes owner's costs and duties
OPEX			
Operations and Maintenance	$M per year	5.25 - 6.0	Assumes 1.5% of CAPEX as operating costs.

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. 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. 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 desalination plant treatment capacity (m^3/day). RR is typically between 0.3 to 0.55 for seawater desalination[71].

The membrane used for reverse osmosis requires chemical cleaning to maintain the process efficiency. 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. Backwash water from the pre-treatment process and membrane cleaning water are typically treated to remove solids or other contaminants prior to being added to the desalination concentrate for discharge.

The typically energy requirement for reverse process describe is about 9-12 kWh/m^3 feed 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 feed 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.

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.

[71] Metcalf and Eddy 5th Edition Table 11-30

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	1,600	40,000 $ / (ML/year) based on Australia Water Association – Desalination Fact Sheets – Summary of Australian Desalination plants[72] The cost has been standardised to 2021 value using Australian Reserve Bank inflation rate. 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)[73]			
▪ Intake and brine discharge structure	%	30	
▪ Pre-treatment	%	15	
▪ Reverse Osmosis Plant	%	25	
▪ Post-treatment (remineralisation)	%	2	

[72] http://www.awa.asn.au/AWA_MBRR/Publications/Fact_Sheets/Desalination_Fact_Sheet.aspx
[73] **https://www.advisian.com/en/global-perspectives/the-cost-of-desalination**

Parameter	Unit	Value	Comment
▪ Product storage and distribution	%	10	
▪ Electrical and instrumentation	%	8	
▪ Civil/site and permits	%	10	
OPEX - Annual			
Power	$M	17	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	6	In-house Aurecon database, 100-200 $ / ML permeate produced, averaged value is used to determine the cost.
Labour	$M	6	In-house Aurecon database, 100-200 $ / ML permeate produced, averaged value is used to determine the cost.
Operation and maintenance	$M	10	In-house Aurecon database. 200 - 300$ / 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[74]. 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[75].

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.

[74] The cost of desalination https://www.advisian.com/en/global-perspectives/the-cost-of-desalination
[75] The cost of desalination https://www.advisian.com/en/global-perspectives/the-cost-of-desalination

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 (See section 7.1.2 for details)
Surface water, dam, river water	Clarification +ultrafiltration, reverse osmosis+ ion exchange
Recycled water (municipal) - assuming secondary effluent after BNR	Ultrafiltration, reverse osmosis, ion exchange
Underground/ borewater	Low salinity - Ultrafiltration, ion exchange
	High salinity - Ultrafiltration, reverse osmosis, ion exchange
Potable water	Reverse osmosis + Ion exchange

7.2.3 Selected hypothetical project

The selected hypothetical project is a demineralised plant (or water treatment plant) to produce highly purified water 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 cleaning 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 using potable water

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	1.36	In-house Aurecon database, 20-30 kWh/m3 feed 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	1.2	In-house Aurecon database.
CAPEX breakdown			
▪ Development cost (including equipment)	%	10	
▪ Construction cost	%	90	
OPEX - Annual			
Power	$	5,000-10,000	In-house Aurecon database
Chemical	$	1,000-2,500	In-house Aurecon database
Labour	$	30,000	In-house Aurecon database, system is fully automated.
Operation and maintenance	$	15,000 -25,000	In-house Aurecon database. Average value, including replacement and maintenance of equipment and membranes

8 Battery Energy Storage System (BESS)

A battery energy storage system (BESS) stores electricity from the network or collocated generation plant, for use as needed at a later point. This section details three BESS types that are relevant to the Australian energy market – large-scale lithium-ion battery storage, residential battery storage and large-scale Sodium sulphur battery storage.

8.1 Large-Scale Lithium-Ion Battery Storage

8.1.1 Overview

Large-scale lithium-ion Battery Energy Storage Systems (BESS) convert incoming alternating current power to a low voltage and then to direct current power through four-quadrant inverters, which is then stored in the batteries. The power can be regenerated back from the batteries to the high voltage AC network through the reverse path.

A large-scale BESS contains several primary components, including the battery system (with cells assembled into modules and racks), battery management system, bi-directional inverters, step-up transformer(s), plant control and monitoring system, HVAC / thermal management systems, and other balance of plant.

Approximately 10 to 20% of the energy supplied to the batteries during the charge operation is lost and not available when the battery discharges. These losses are mainly due to the BESS HVAC load and referred to as the round-trip efficiency losses.

8.1.2 Typical options

A large-scale BESS can be used for a wide range of network services, including energy market participation (i.e. arbitrage), load shifting, a range of market and non-market ancillary services (in particular FCAS services), and cost mitigation to avoid or reduce network upgrades, demand charges, fuel costs, and the FCAS ‘causer pays’ exposure of intermittent wind and solar generators. A BESS can also be used to protect NEM interconnectors or increase transfer flows, with for example the Hornsdale Power Reserve and Dalrymple BESS systems participating in the Special Integrated Protection Scheme (SIPS) of the SA-Vic Heywood interconnector, and the Victorian Big Battery contracted to provide a SIPS service for the NSW-Vic VNI interconnector. The modular nature of a BESS enables it to be sized in both power and energy to meet highly specific and varied project requirements.

Batteries used for bulk energy shifting and arbitrage typically have greater than one hour of energy storage, whereas, batteries used primarily for network support services or renewable integration may have less than one hour of storage.

Lithium ion has become the dominant battery technology in recent years, primarily due to falling costs, developments in the range of cell chemistries for different applications, high power and energy density (small physical size), and high efficiency. Within the lithium ion battery class are a number of sub-categories of cell chemistries. Each of these has different performance, life, and cost characteristics which may be used for different purposes.

BESS units have a range of packaging approaches, including separate or combined battery and inverter enclosures, stand-alone buildings, or outdoor modular cabinet type arrangements. The leading OEMs provide modular, prefabricated containerised solutions.

8.1.3 Recent trends

Development pipeline

There are currently thirteen large-scale Li-ion BESS operating within Australia, with the largest being the 300 MW / 450 MWh Victoria Big Battery in Victoria. These systems are connected to the National Electricity Grid (NEG), except for two smaller batteries which are located within isolated mine site grids in Western Australia.

A further twelve large-scale BESS are currently under construction, ranging in size from the 10 MW / 10 MWh Lincoln Gap BESS to the 250 MW / 250 MWh grid-forming Torrens Island BESS, with many more projects in the development pipeline[76]. Selected recent BESS installations on the NEM and those expected to be constructed in 2023 include:

- Bouldercombe (Qld) – 50 MW / 100 MWh
- Broken Hill (NSW) – 50 MW / 50 MWh
- Capital Battery (ACT) – 100 MW / 200 MWh
- Chinchilla (Qld) – 100 MW / 200 MWh
- Darwin (NT) – 35 MW / 35 MWh
- Latitude Solar Battery (NSW) – 5 MW / 11 MWh (constructed)
- Wallgrove (NSW) – 50 MW / 75 MWh (operational)

Although the current fleet of operating large-scale BESS projects incorporate an average of 1.4 hours of energy storage (weighted to account for battery power rating), average storage capacity is expected to increase towards 2 hours in the coming years and will include systems with up to 4 hours of storage. This is reflected within the BESS projects currently under construction, which includes four examples of 2-hour systems. 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, notwithstanding the recent rise in battery prices due to lithium carbonate resource costs.

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 around 200 MW and larger for announced projects[82].. 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 8.1.4 and 8.1.5. However, the technical and cost attributes can be scaled to represent other power capacities as needed.

Costs

Large-scale BESS project costs have risen significantly throughout FY 21/22, with total BESS EPC costs increasing by approximately 25 – 38% across the storage duration range of 1 to 8 hours. This has been driven primarily by the following factors:

- Increase in lithium carbonate commodity price by a factor of approximately 5.3 throughout FY 21/22. This has caused a significant increase in the cost of lithium-ion battery cells and is the most significant factor in the overall increase in BESS costs.
- Cost increases and volatility of other raw materials used in inverters, transformers and other balance of plant, including aluminium and copper, as well as microchip shortages
- Increase in logistics costs and challenges in relation to international trade due to several factors, including war in Ukraine, Covid-19 impact on shipping lines, collapse of ports and increase in transport energy costs

[76] https://reneweconomy.com.au/big-battery-storage-map-of-australia/

- Accelerating demand for lithium-ion battery EVs and stationary storage globally, including US tax incentives for storage projects

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 (i.e. solar and wind farms) are also increasingly interested in large BESS integration/co-location at the same grid connection point (e.g. Lake Bonney Wind Farm). For these co-located installations, currently the BESS is typically arranged to have a separate HV connection point at the same substation as the renewable generator. There are also some development synergies associated with GPS studies and development approvals to develop BESS projects in parallel with VRE projects.

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. Following commencement of this reform, arrangements with the BESS connected at a common MV bus (i.e. 33 kV) with the renewable generator and sharing the same step-up transformer is expected to be common.

Due to restrictions placed on generators in South Australia by the Office of the Technical Regulator, many generators are also increasingly looking to install battery systems with their generation to meet Fast Frequency Response (FFR) requirements.

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. AEMO has recognised the enormous potential of grid-forming inverters to support the energy transition and is looking at ways to encourage implementation of this technology in large-scale BESS development[77]. The Dalrymple BESS and Hornsdale Power Reserve are the two grid-forming batteries currently operating on the NEM. The Torrens Island BESS currently under construction will also operate in grid-forming mode.

8.1.4 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 plausible project for installation in the NEM, given the above discussion on typical options and current trends.

Table 8-1: **BESS configuration and performance**

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Configuration						
Technology		Li-ion				
Performance						
Power Capacity (gross)	MW	200				
Energy Capacity	MWh	200	400	800	1,600	
Auxiliary power consumption (operating)	kW	2,300	3,100	4,800	8,300	Indicative figures (highly variable, dependent on BESS arrangement, cooling systems etc.).
Auxiliary power consumption (standby)	kW	900	1,800	3,600	7,200	Based on Aurecon internal database of similarly sized projects, Indicative figures (highly dependent on BESS arrangement, cooling systems etc.).

[77] "Application of Advanced Grid-scale Inverters in the NEM", AEMO, August 2021

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Power Capacity (Net)	MW	197.7	196.9	195.2	191.7	
Seasonal Rating – Summer (Net)	MW	197.7	196.9	195.2	191.7	Dependent on inverter supplier. Potentially no de-rate, or up to approx. 4% at 35°C.
Seasonal Rating – Not Summer (Net)	MW	197.7	196.9	195.2	191.7	
Annual Performance						
Average Planned Maintenance	Days / yr.	-				Included in EFOR.
Equivalent forced outage rate	%	1 - 2				Dependent on level of long-term service agreement, retention of strategic spares etc.
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 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.
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 8-2: 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	83	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	91.5	Assumed to be half of the round-trip efficiency.
▪ Discharge efficiency (BOL)	%	92	92	92.5	91.5	Assumed to be half of the round-trip efficiency.

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
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. 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.
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. 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				Extended project life with battery upgrades.

8.1.5 Cost estimate

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

Table 8-3: 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	439	439	439	439	Indicative cost for power related components and other costs independent of storage duration
Relative cost - Energy component	$ / kWh	431	418	411	404	Indicative cost for energy related components
Total EPC cost	$M	174.0	255.0	416.6	734.2	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	150.7	220.9	360.8	635.9	As above.
▪ Installation cost	$M	23.3	34.1	55.8	98.3	As above.
CAPEX – EPC cost for 200 MW BESS (co-located with large renewable installation)						
Relative cost - Power component	$ / kW	389	389	389	389	Indicative cost for power related components and other costs independent of storage duration
Relative cost - Energy component	$ / kWh	431	418	411	404	Indicative cost for energy related components
Total EPC cost	$M	164.0	245.0	406.6	724.2	Based on an assumed $10,000,000 savings in transformer and associated grid voltage equipment (i.e. cost worn by co-located project)
▪ Equipment cost	$M	142.0	212.2	352.2	627.2	As above.
▪ Installation cost	$M	22.0	32.8	54.4	97.0	As above.
Other costs						
Cost of land and development	$	10,000,000				
OPEX – Annual						
Fixed O&M Cost	$/MW (Net)	3,900	5,300	7,900	13,600	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	771	1,042	1,542	2,607	Highly variable between OEMs. Annual average cost over the design life Does not include battery replacement cost at end of Economic Life (Design Life)
Extended warranty (20-year battery life)	$/MW (Net)	3,200	4,800	8,300	15,100	Indicative annual average cost for 20-year extended warranties for LFP batteries
Total annual O&M Cost (including extended warranties)	$k	1,404	1,986	3,162	5,502	Highly variable between OEMs. Annual average cost over the design life

8.2 Residential Battery Storage

8.2.1 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 utilise Lithium-ion technologies. The RBESS industry is relatively immature, and this is manifest through product quality problems and volatility among market players. 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, and also as a back-up reliability measure in case of grid outages. Price reductions in Li-ion batteries over the medium to long term are expected to drive increased uptake of RBESS. However, the recent elevated lithium carbonate resource costs have caused battery prices to increase which will likely suppress the sector's growth in the short term.

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.

8.2.2 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, followed by Lithium Nickel Manganese Cobalt Oxide (NMC). As an alternative to Lithium-Ion technology, Redflow Zcell offers a Zinc-Bromide flow battery product.

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) and back-up during grid power outages. 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 electrical system of a household. Depending on how the system is positioned electrically, 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 2-13 kW are readily available, with most products falling in the range of 2-5 kW. 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 many RBESS manufacturers and a large range of products integrating different system components, services and levels of quality, as reflected in the broad price range across these products.

8.2.3 Recent trends

The Clean Energy Council estimates that 34,731 household batteries with a combined capacity of 347 MWh were installed in Australia in 2021, which is an increase on the 23,796 batteries (238 MWh combined capacity) installed in the previous year[78]. New South Wales and Victoria had the largest number of new systems installed in 2021. Much of the growth was likely driven by state government battery rebate schemes available over the last couple of years, with only those in Victoria and the ACT still active. As approximately 30% of Australian households have rooftop PV systems, there is large scope for the retrofitting of PV-tied battery systems as the price of batteries falls in the medium to long term.

The RBESS market is still relatively immature. An independent testing facility performing accelerated testing on battery products has highlighted the large variation in product quality [79]. The study 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 (i.e. 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 shift towards high-voltage systems which are more efficient and easier/cheaper to install due to the smaller cable sizes. The study has also found a large

[78] Clean Energy Australia Report 2022, Clean Energy Council
[79] Public Report 12 (Final Report) – Lithium-ion Battery Testing, ITP Renewables, March 2022

variation in energy capacity degradation rates across the products tested, while system efficiency was less variable.

8.2.4 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: 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).
Power Capacity (Net)	kW	4.95	
Seasonal Rating – Summer (Net)	kW	4.95	Dependent on inverter supplier. Potentially no de-rate, or up to approx. 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 approx. 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 8-5: 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 approx. 250 ms typical for frequency response, within approx. 1 s 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[80].
Charge efficiency	%	95	Assumed to be half of the round-trip efficiency.

[80] Public Report 12 (Final Report) – Lithium-ion Battery Testing, ITP Renewables, March 2022

Item	Unit	2 hours	Comment
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.

8.2.5 Cost estimate

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

Table 8-6: 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	$	16,000	
Equipment cost	$	12,900	As above.
Installation cost	$	3,100	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.

8.3 Large-Scale Sodium Sulphur Battery Storage

8.3.1 Overview

Sodium-based batteries, specifically Sodium Sulphur (NaS) Batteries, have the potential to become a significant alternative and/or complementary storage solution to large-scale lithium-ion BESS over the coming decades.

NaS batteries consist of a molten sodium anode and a molten sulphur cathode, separated by a solid beta alumina ceramic electrolyte. The battery needs to be maintained at temperatures of 300-350°C, such that the sodium remains in a liquid state. Figure 8-1 presents a schematic of the chemistry of a NaS battery.

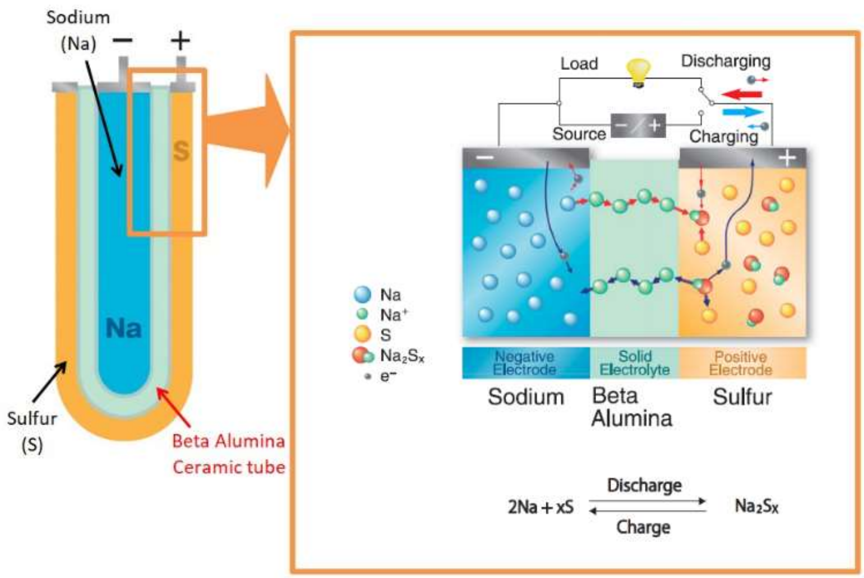

Figure 8-1: NaS battery chemistry

The typical technical characteristics of large-scale NaS BESS compared to Li-ion BESS are presented in Table 8-7.

Table 8-7: Comparison of technical parameters of NaS and Li-ion batteries

Parameter	NaS	Li-ion (LFP)
Design life	15	15-20
No. cycles	4,500	5,500-7,300
Battery efficiency[1]	80-90%	90-95%
Min. State of Charge (SOC)	20%	0%
Degradation	- [2]	-1.8%/annum
Approx. energy density	220 Wh/kg	260 Wh/kg
Typical C-rate	0.15	< 1.00
Operating temperature	300-350°C	20-26°C

Notes: 1. Efficiency of batteries only, not including additional system losses contributing to round-trip efficiency at the Point of Connection; wide range of NaS efficiency values were stated in the available literature.
2. Information regarding the degradation rate of NaS batteries was not readily available.

As shown above, Li-ion batteries demonstrate superior performance to NaS batteries across the key technical parameters, although typical degradation rates for NaS batteries could not be determined from the available literature.

The required high operating temperature range of NaS batteries results in significant additional operational costs compared to Li-ion systems. A promising area of research is room-temperature NaS batteries, with significant advancements being made in the reducing degradation modes of these batteries[81]. However, this technology is not yet commercially deployable.

A distinguishing feature of NaS batteries is the required low C-rate which drives use cases for large-scale NaS BESS towards energy-intensive rather than power-intensive applications (i.e. those suitable to storage durations of 6+ hours).

The main perceived advantage of NaS batteries lies in the abundance of low-cost sodium and sulphur relative to lithium. While NaS BESS are still not yet commercially competitive with Li-ion systems, they may become more so as the industry develops (i.e. through economies of scale) and in light of current and possible future resource constraints around lithium.

8.3.2 Deployed capacity

Information regarding total global capacity of NaS large-scale BESS is not readily available. However, Japan has 300 MW of NaS BESS installed[82].

NGK, the leading supplier of NaS batteries, has installed most of the large-scale NaS BESS globally, notably:

- 270 MW of stored energy suitable for 6 hours of daily peak shaving have been installed in Japan.
- 15 NaS BESS acting in coordination provide 108 MW / 648 MWh to defer fossil generation investment and provide frequency response and voltage control services have been installed in Abu Dhabi.

Figure 8-2 shows the NaS BESS systems installed by NGK across the world.

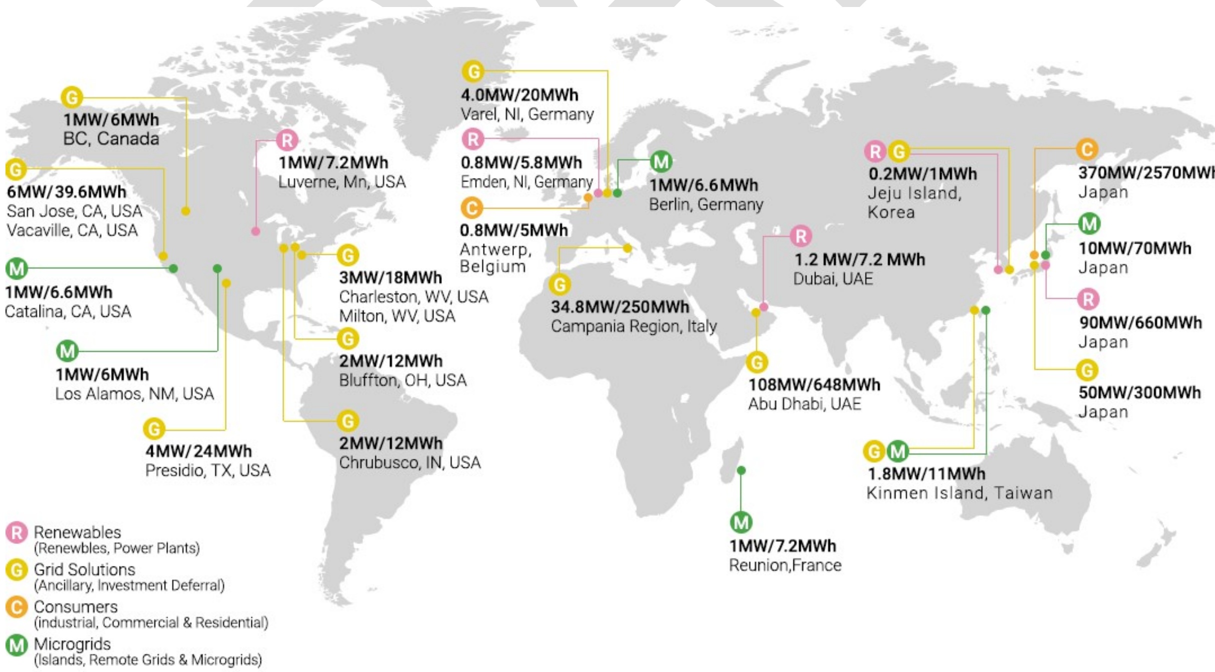

Figure 8-2: NGK Insulators Insulation Record

81 'Stable Dendrite-Free Sodium-Sulfur Batteries Enabled by a Localized High-Concentration Electrolyte', J. He et al., Am. Chem. Soc. 2021
82 'Sodium Sulfur Battery Market Size, Share & Trends Analysis Report By Application', Grand View Research [Online], 2020

NGK currently offers containerised 86-tonne and 132-tonne BESS systems, with capacities of 0.8 MW / 4.8 MWh and 1.2 MW / 8.64 MWh respectively. These are designed to be modular to allow scaling to an overall desired system capacity.

8.3.3 Use cases

The major suppliers of NaS batteries are NGK INSULATORS (as mentioned above), LTD and BASF SE. Other players that have contributed to the development of these batteries are AEP (American Electric Power Corporation, Inc.), EaglePicher Technologies, FIAMM Energy Technology, KEMET Corporation, Mitsubishi Electric Corporation, POSCO, Sieyuan Electric Co, LTD, The General Electric Company and Tokyo Electric Power Company Holdings[83].

Table 8-8 describes some of the large-scale NaS BESS currently deployed and applications.

Table 8-8: List of current NaS batteries in use[84] [85] [86]

Location	Capacity	Storage Duration (hr)	Application	Battery supplier
Catalina Island, CA, USA.	1MW / 7.2 MWh	7.2	Optimization of diesel generator usage in microgrid; grid stability	BASF
Varel, DEU	4MW / 20 MWh, paired with 2.5 MWh Li-Ion batteries	5.0	Grid stability, electricity trading	BASF
Naples area, Italy	34.8 MW / 250 MWh	7.0	Transmission grid stability	BASF
Abu Dhabi, UAE	108 MW / 648 MWh	6.0	Multiple grid service applications	BASF, NGK Insulators
Buzen, Kyushu Island, Japan	50 MW / 300 MWh.	6.0	Renewable energy integration	BASF
Antwerp, Belgium	950kW / 5.8 MWh	6.0	Interlinked and integrated production, market platforms and technologies serve the company's supply chains to various off-taker industries.	BASF, NGK Insulators
Uliastai, Mongolia	600 kW / 36MWh	6.0	Part of a wider initiative to increase the use of renewable energy in Mongolia.	NGK Insulators

As described above, NaS batteries are deployed for a range of applications. The low C-rate/longer-storage duration of these batteries makes them particularly useful for energy-intensive applications such as load shifting to support renewable energy integration.

8.3.4 Commodity risks

Both sodium and sulphur can currently be sourced at low costs and are readily available commodities.

[83] Sodium Sulfur Battery Market Report 2022-2032. London : Visiongain Reports Ltd., 2022.
[84] 'BASF switches on 5.8MWh NGK sodium-sulfur battery storage system in Belgium', A. Colthorpe, Energy Storage News [Online], 4 October 2021
[85] 'Overview of Lithium and Energy Battery Technologies', H. Ueda, Deakin University, ABRI Presentation [Online], 22 August 2022.
[86] 'Proven Technology', BASF [Online], 2022.

Sodium is one of the most abundant materials on the earth, comprising 2.6% of earth's crust. Due to its high reactivity, elemental sodium naturally occurs within compounds and is typically extracted through electrolysis of mineral sodium chloride. Sodium hydroxide (caustic soda) is the compound typically used to generate the sodium ions used in batteries. The resource cost of sodium hydroxide varies considerably by location but is in the range of AU$200-500/metric tonne, compared to $78,000/metric tonne for the lithium hydroxide used in the production of Li-ion batteries[87]. Due to this low cost, any increases in sodium resource costs are expected to have a lower proportional impact on the overall cost of NaS batteries[88]. Significant growth in global sodium consumption is expected over the coming years due to its use across many industries including dye production, metal manufacturing and other chemical processes. However, due to the abundance of sodium across the earth and the relative ease of increasing production to respond to demand, overall supply risk of sodium is rated as low (4/10) by the Royal Society of Chemistry (RSC) relative to lithium (6.7/10)[89]. The RSC rating takes into account factors such as abundance, distribution and production locations of the metal.

Sulphur is also currently considered to be abundant and cheap, with prices often occurring below AU$150/metric tonnes in recent years. However, significant spikes of up to AU$800/metric tonne have occurred in some regions recently as a flow-on effect from crude oil and fertiliser market volatility due to geopolitical forces[90]. Most of the world's sulphur is produced as a byproduct to fossil fuel production, with the remainder being mined directly from the earth or extracted as a byproduct to copper mining. One the most important applications for sulphur globally is sulphuric acid used in the production of fertilisers. Although the current RSC supply chain risk rating for sodium is low (3.5/10), research suggests that a significant sulphur shortfall may arise by 2040 due to reduced production of oil and gas as societies move towards decarbonisation goals[91]. This is likely to drive up commodity prices while alternative production means are developed, noting that many of the current direct mining techniques have major adverse environmental consequences.

In summary, the key constituents in NaS batteries – sodium and sulphur – do not present major supply chain risks in the short term, particularly compared to lithium. However, sulphur may be subject to supply chain pressures and increased prices in the medium to long term.

8.3.5 Development and cost trends

The International Renewable Energy Agency (IRENA) has estimated that the installation costs of high-temperature NaS BESS may decrease by 56-60% by 2030, from current costs of approximately AU$520/kWh down to AU$250/kWh.[92] Another source estimated current capital costs to be AU$350/kWh [93]. These capital costs are similar to those applicable to a large-scale Li-ion BESS on a per MWh basis. However, this does not take into account the lower lifetime energy throughput for NaS BESS due to the inferior performance characteristics compared to Li-ion BESS (as shown in Table 8-7), as well as higher operational costs due to the high-temperature operating conditions of these batteries. Therefore, NaS BESS are still currently considered to be more expensive than Li-ion BESS.

Significant growth is expected within the NaS industry. The Sodium Sulphur Battery Market Report 2022-2032 published by Visiongain stated that "the global Sodium Sulphur battery market was valued at US$444 million in 2021 and is projected to grow at a Compound Annual Growth Rate (CGAR) of 24.9% during the forecast period 2022-2032". This is nearly 1% of the value of the lithium-ion battery market, which is currently valued at $44.5 billion with a CGAR of 13.1%.[94]

[87] 'Sodium comes to the battery world', A. Scott, Chemical & Engineer News [Online], 24 May 2022.
[88] 'Will sodium-ion battery cells be a game-changer for electric vehicle and energy storage markets?', Wood Makenzie [Online], 14 Sep 2021
[89] Royal Society of Chemistry [Online], https://www.rsc.org/periodic-table/
[90] Sulphur Price Trend & Forecast, ChemAnalysis, [Online], 10 Oct 2022
[91] 'Sulfur shortage: a potential resource crisis looming as the world decarbonises', M. Greaves et al, Royal Geographical Society, 22 August 2022.
[92] 'Electricty Storage and Renewables Costs and Markets to 2030', IRENA, 2017.
[93] 'Storing energy in China – an overview', H. Chen et all, Storing Energy (Second Edition), 2022'
[94] 'Lithium - Ion Battery Market', Markets and Markets [Online], September 2022.

9 Compressed Air Energy Storage System

9.1 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.

9.1.1 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.

- Energy conversion system (motor, compressor, turbine and generator, electrical switchroom)
- Air storage system (Cavern, water surface reservoir and shaft)
- 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.

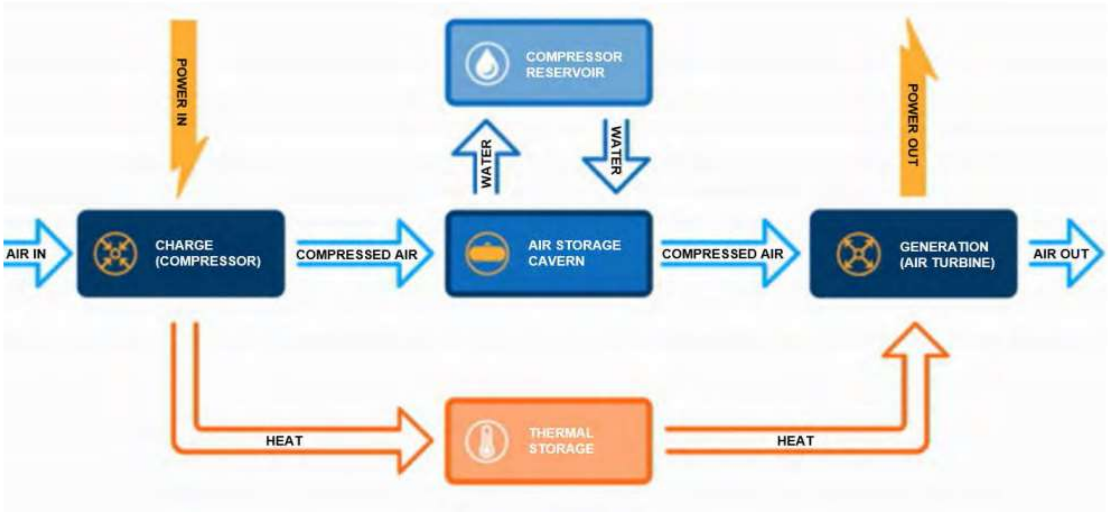

Figure 9-1: Hydrostor A-CAES Technology (Ref: TWD Report – Independent Engineering Assessment of Scalable 100MW A-CAES Design, 2021

9.1.2 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.

Hydrostor has many A – CAES projects currently at various stages of project development. Some of these projects are listed below.

- Willow Rock Energy Storage Centre in Kern County, California (500 MW A- CAES system for 8 hours of storage)
- Cheshire Energy Storage Centre, UK (UK's department of Business Energy and industrial Energy provided funding to assess long duration energy storage using mothballed gas cavities)

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.

9.1.3 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 9-1:: A-CAES configuration and performance

Item	Unit	12 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	2400	600	
Auxiliary power consumption (operating)	kW	Negligible	Negligible	Included in Round Trip Efficiency[95]
Auxiliary power consumption (standby)	kW	Negligible	Negligible	Included in Round Trip Efficiency[95]
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	320,000 - 350,000[96]	80,000 – 90,000	
Cavern/vessel air pressure	Bar	60		
Cavern/vessel air temperature	^0C	40	40	
Surface reservoir volume	m^3	360,000[95]	N/A	
Thermal storage volume	m^3	19,200[96]	4,800	
Thermal storage temperature/Pressure	^0C/Bar	210/20[96]	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[95]	Negligible	

[95] Hydrostor: Advanced Compressed Air Energy Storage: Technology & Project Delivery Overview 2020
[96] Feasibility study of adiabatic compressed air energy storage in porous reservoirs, Jason et. Al, CSIRO Publishing, the APPEA Journal, 2022

Table 9-2: 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[95]	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[95]	5	
Synchronous condenser mode (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[95]
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[95]	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	2022	2022	2022
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	30-50 years	30-50 years	Same as any rotating plant
Technical Life (Operational Life)	Years	30 years	30 years	Same as any rotating plant

9.1.4 Cost estimate

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

Table 9-3: Cost estimates

Item	Unit	A-CAES with cavern storage for 12 hours	A-CAES with vessel storage for 12 hours	Comment
CAPEX – EPC cost				
Relative cost - Power component	$ / kW	1700	1700	Indicative cost for power related components. Relative cost does not include land and development costs.
Relative cost - Energy component	$ / kWh	200	650	Indicative cost for sub-surface cost
Total EPC cost	$M	820	475	Based on Aurecon internal database of similarly sized projects and scaled for additional energy storage capacity.
▪ Equipment cost	$M	574	333	As above.
▪ Installation cost	$M	246	142	As above.
Other costs				
Cost of land and development	$	20,500,000	11,875,000	2.5% of EPC cost on lease basis
OPEX – Annual				
Fixed O&M Cost	$/MW /year	30,000	30,000	Provided on $/MW/year basis for input into GenCost template only.
Variable O&M Cost	$/MWh	4.0	4	Assumed one cycle a day
Total annual O&M Cost	$M	9.5	2.4	Annual average cost over the design life

10 Capacity Factors for New Solar and Wind Generators

10.1 General

As part of this exercise, AEMO has requested a forecast of benchmark new entrant capacity factors for the following technologies:

- Solar PV - single axis tracking
- Wind - onshore
- Wind - offshore

The intention is to provide an indication of the likely future capacity factor improvements in a NEM context for long-term forecast purposes.

10.2 Capacity factor drivers

Capacity factors for wind and solar PV are dependent to some extent on the technology, but are more affected by the resource at the project location as well as the design of the project as a whole. Generally speaking, the capacity factor is the result of optimising the cost of energy and not significantly affected by technological advancement. Achieving notably higher capacity factors with wind turbines, and to a lesser extent Solar PV, is possible however with inefficient increases in capital cost.

For SAT solar PV, for a given solar resource, capacity factors can be increased by either increasing the spacing between rows of modules or by increasing the DC installed capacity. Both of these increase the equipment and land cost. Whilst the cost of modules may have some potential to gradually decrease in the future, we expect the optimum capacity factor to not change significantly. Capacity factor is also increased if sites with higher irradiance are used. The development of the grid and renewable energy zones is likely to make areas with good resource available, however fleet-wide averages are expected to increase only marginally. Further improvements in capacity factors beyond the next 10 to 15 years may be unlikely to be commercially attractive particularly if the rate of cost reduction of modules and other components over this time is not significant.

More generally, for wind turbine projects capacity factor is subject to opposing influences making it difficult to predict future capacity factors with a level of confidence as summarised below:

- As better sites with higher wind speeds get taken, wind resource at remaining sites will be lower i.e. lower capacity factor
- Hub heights are increasing to access higher wind speeds and therefore achieve higher capacity factor
- Larger rotor sizes, which roughly follow the hub height, are increasingly difficult to achieve due to design/ manufacture, construction and transport constraints as well as potential approval restrictions. This will potentially put downward pressure on capacity factors for wind, ie turbines may have relatively higher rated power compared to rotor diameter. This is presently the case with the largest available onshore turbines having rated power of 6 MW and rotor diameters of 160-170 m. This is equivalent to 130-140m for a 4 MW turbine, but the slightly older 4 MW turbines are available with rotor diameters up to 150m. Therefore, the presently available 6 MW turbines will have lower capacity factor at lower wind speed sites. It is unclear how this trend will continue.
- Conversely, there may be a need to reduce power variability into the network which is achieved by a smaller SRP i.e. higher capacity factor

Theoretical Australian offshore resource potential has not been reviewed or examined as part of this exercise.

For this analysis NEM based projects have been assumed to be in line with the hypothetical projects represented throughout this report.

10.3 Capacity factor projections

The projected capacity factor trends shown in Table 10-1 intend to indicate NEM fleet wide trends over time and are based on continued improvements along the current long-term global weighted average trend as reported by IRENA, 2019[97].

Table 10-1: Capacity Factors for new solar and wind generators

Year	Solar PV - Single axis tracking [%]	Wind - Onshore [%]	Wind – Offshore [%]
2022-23	29.5	40.0	48
2023-24	29.6	40.3	48.6
2024-25	29.8	40.6	49.2
2025-26	29.9	41.0	49.8
2026-27	30.1	41.3	50.4
2027-28	30.2	41.6	51
2028-29	30.4	41.9	51.6
2029-30	30.5	42.2	52.2
2030-31	30.7	42.6	52.8
2031-32	30.8	42.9	53.4
2032-33	31.0	43.2	54
2033-34	31.0	43.5	54.6
2034-35	31.0	43.8	55.2
2035-36	31.0	44.2	55.8
2036-37	31.0	44.5	56.4
2037-38	31.0	44.8	57
2038-39	31.0	45.1	57.6
2039-40	31.0	45.4	58.2
2040-41	31.0	45.4	58.2
2041-42	31.0	45.4	58.2
2042-43	31.0	45.4	58.2
2043-44	31.0	45.4	58.2
2044-45	31.0	45.4	58.2
2045-46	31.0	45.4	58.2
2046-47	31.0	45.4	58.2
2047-48	31.0	45.4	58.2
2048-49	31.0	45.4	58.2
2049-50	31.0	45.4	58.2

However, considering the range of factors discussed in Section 10.2, the future trend for onshore wind farm capacity factors for the reference project in Table 4-1 is uncertain and as such the projection in Table 10-1 may be considered optimistic with no change also a possible outcome. Similarly, the projection in Table 10-1 for offshore windfarms for the reference project in Table 4-4 may also be optimistic and it is difficult to comment further in an Australian context in the absence of any data for Australian projects.

97 IRENA (2019), Renewable Power Generation Costs in 2018, International Renewable Energy Agency, Abu Dhabi

Appendix A
AEMO GenCost 2022 Excel Spreadsheet

Spreadsheet to be provided separately

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