DNM RENEWABLE HYDROGEN FEASIBILITY STUDY

ANT ENERGY SOLUTIONS

&

DYNO NOBEL MORANBAH

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Purpose

The purpose of this report is to share the learnings from the Dyno Nobel Moranbah (DNM) and ANT Energy Solutions (ANT) renewable hydrogen ammonia feasibility study undertaken in 2019 and 2020.

Acknowledgement

This project received funding from the Australian Renewable Energy Agency (ARENA) as part of ARENA's Advancing Renewables Program.

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ANT is a preferred integrator of Hydrogenics (Cummins Inc.) hydrogen system equipment for the Australian market.

Nomenclature

Acronym	Description
AC	Alternating Current
ACQ	Agreed Contract Quota
AEMO	Australian Energy Market Operator
AN	Ammonium Nitrate
ANT	ANT Energy Solutions
ATO	Australian Tax Office
BOM	Bureau of Meteorology
BOP	Balance of Plant
BOS	Balance of Stack
BTM	Behind the Meter
CAPEX	Capital Expenditure
CCS	Carbon Capture & Storage
CEDI	Continuous Electrodeionisation
CF	Capacity Factor
CPI	Consumer Price Index
CSIRO	The Commonwealth Scientific and Industrial Research Organisation
DC	Direct Current
DI water	Demineralised Water
DNM	Dyno Nobel Moranbah
EBITDA	Earnings Before Interest Taxation Depreciation and Amortisation
EPC	Engineer, Procure & Construct
EPCM	Engineer, Procure & Construct Management
FCPM	Fuel Cell Power Module
FEED	Front End Engineering Design
GCR	Ground Coverage Ratio
GFT	Ground Fixed Tilt
GH	Grey Hydrogen
GHI	Global Horizontal Irradiance
H_2	Hydrogen
H_2O	Water
HAZOP	Hazard and Operability Study
HV	High Voltage
HVAC	Heating, Ventilation and Air-Conditioning
IAR	Impact Assessment Report
IPL	Incitec Pivot Ltd
IRR	Internal Rate of Return
KOH	Potassium Hydroxide
LCOE	Levelised Cost of Energy
LCOH	Levelised Cost of Hydrogen
MCC	Motor Control Centre
MPPT	Maximum Power Point Tracker
MVPS	Medium Voltage Power Station
NH_3	Ammonia
NPAT	Net Profit After Tax
NPV	Net Present Value
O_2	Oxygen
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
ORC	Organic Rankine Cycle
P&ID	Piping and Instrumentation Diagram
PEM	Proton Exchange Membrane
PLC	Programmable Logic Controller
PPA	Power Purchase Agreement
PV	Photovoltaic
RFP	Reinforced Fibre Polymer
RH	Renewable hydrogen
RHF	Renewable hydrogen Facility
RO	Reverse Osmosis
ROM	Rough Order of Magnitude
SAT	Single Axis Tracking
SHE	Safety Health & Environment
SLD	Single Line Diagram

SMR	Steam Methane Reforming
TBD	To be Determined
TIC	Total Installed Cost
TMY	Typical Meteorological Year
TRL	Technology Readiness Level
VSD	Variable Speed Drive
Unit	**Description**
AU$ (AUD)	Australian Dollar
bar	Metric Unit for Pressure
EUR	European Monetary Unit
ft	Foot/Feet
g	Grams
GW	Giga Watt
GWh	Giga Watt Hour
Ha	Hectares
kg	Kilograms
kg/h	Kilograms per Hour
kL	Kilo Litres
km	Kilometres
ktpa	Kilo Tonnes per Annum
kW	Kilo Watt
kWh	Kilo Watt Hour
M	Million
m	meter
MAWP	Maximum Allowable Working Pressure
MW	Mega Watt
MWh	Mega Watt Hour
pa	Per Annum
t	Tonnes
t/h	Tonne per Hour
tpa	Tonnes per Annum
tpd	Tonnes per Day
US$ (USD)	United States Dollar
V	Volts
W	Watt
¥	Yen

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1. Executive Summary & Key Findings

The purpose of this report is to present the outcomes of an engineering and economic feasibility study to evaluate the construction of a renewable hydrogen facility (RHF) for production of feedstock for the Dyno Nobel Moranbah (DNM) ammonium nitrate production facility in Moranbah, Queensland. The study was commissioned by DNM and undertaken by ANT Energy Solutions (ANT).

The maximum purchase price of renewable hydrogen (RH) was calculated by DNM based on next-best-alternative comparison with imported ammonia. The investment in additional ammonia manufacturing capacity could be justified if the cost of hydrogen supplied to DNM was below AU$2 per kilogram. Accordingly, this report examines the viability of developing a renewable hydrogen facility with hydrogen offtake at this price.

A long-term take-or-pay RH offtake agreement provides a secure basis for equity investment in the RHF. Market engagement has identified numerous investors interested in providing equity investment in the RHF, however all investors require an internal rate of return (IRR) of greater than 4%, with most expecting significantly higher due to the scale-up and long-term operational risks.

A facility was designed that could reliably provide a continuous supply of RH suitable for ammonia manufacturing from a solar energy supply. The nominal daily hydrogen supply to DNM was met >96% of the time in an average year. 10% of annual RH production could be sold seasonally as surplus production in an average year. Solar farm capacity factor was found to be 28% while electrolyser capacity factor was 38%.

The feasibility study has found that the RHF is technically viable and can be cash flow positive. The large size of the project allows for operational fixed costs to be spread over higher production, resulting in lower fixed costs per tonne and also benefits from lower unit equipment costs due to purchasing scale discounts and integration opportunities. Building a dedicated solar farm has the impact of essentially capitalising future energy consumption, resulting in much higher capital costs than grid-connected concepts, but a lower lifecycle cost. The relatively low capacity factor (CF) of the electrolysis facility also increases upfront capital costs as the scale of electrolysis and hydrogen storage is increased.

Behind-the-meter solar power was found to provide the highest project returns, with the cost of grid-connected renewables too high to provide positive operating cashflow. Single-axis tracking and DC to DC connection between solar farm and electrolysis plant were found to significantly improve project returns. PEM electrolysis technology was found to have a significantly lower lifecycle cost than alkaline electrolysis in this application.

The capital cost for construction of the RHF was estimated at $674M (+/-20%), with 35% of the total cost for renewable energy supply via a dedicated 240MW solar farm, 36% of the total cost for H_2 generation via 160MW of PEM-based electrolysis capacity, 16% of the total cost for 54t of pressurised hydrogen storage and 13% of the total cost for general plant and utilities.

The RHF would be cash-positive at an operating level, with average EBITDA margins of 15%, however the high upfront capital investment without government support would deliver an -5% IRR after tax well below the minimum investment requirement. The high upfront

CAPEX also delays simple payback until at least year 45, well beyond the nominal project life.

The study identified that there are no useful benchmarks available to estimate construction and operating costs for large-scale electrolysis plants and reported solar farm construction and operating costs varied widely. This made it difficult to estimate operating costs accurately which directly impacted projected returns.

If the project only supplied Dyno Nobel RH, to achieve an IRR of 5% on equity contribution, the project would require $396M in grant funding, or 59% of the total RHF CAPEX. With this contribution, the project NPV of 5% is $164M over the 25-year life. The project is cash-positive at an operating level; however, the high upfront capital investment delays simple payback until year 31, beyond the nominal project life.

If the market is available, returns can be significantly improved by monetising surplus hydrogen production into higher-value applications such as transport. Sale of all surplus hydrogen at AU$6/kg would improve the IRR on the $674M investment to 0%, reducing the grant funding required to achieve an investable return to $265M (39%). It was identified that no RH consumers for transport are currently available near the scale required to consume the >800 tpa of surplus RH and that the investment to develop these consumers will require a reliable supply that may not align with seasonal surplus.

Whilst the IRR at AU$2/kg for RH is non-investable without significant government support, the study found that a RH sale price of AU$3.56/kg for the required volume supplied to Dyno Nobel and the excess RH sold at AU$6.00/kg to domestic markets would achieve post tax IRR of greater than 4% without any grant funding. At current foreign exchange rates, assuming ~AU$1.00 (the AU$1 estimate is based on delivering 1130kg of compressed hydrogen (500 bar) in a 40ft shipping container for approximately $1000 per container from the Australian East Coast to Japan) for transport, this price could meet the Japanese target delivered hydrogen price of ¥330/kg (approximately AU$4.56/kg) between 2025 to 2030. This demonstrates the potential economic viability of producing RH in Australia for export markets. The domestic forecast for hydrogen in mobility application is AU$10/kg.

In order for Australia to export RH the following conditions must be met:

- The production cost (including return on investment) must be below the market price
- Domestic capabilities to build, operate and maintain RH production facilities must be developed and demonstrated, and the cost base proven
- RH demand must be secured with long-term contracts to underpin investment
- Production must be at sufficient scale to meet demand (both local and export)

These conditions are no different for domestic production.

The know-how, skills, capabilities and technology applied to and developed from building and operating the facility would be transferable to further RH production facilities in Australia, de-risking such projects. This would provide private sector financiers with greater confidence for investing in RH production in Australia. It would also provide potential overseas customers with confidence to enter into long-term offtake agreements.

To demonstrate export capability, overseas offtake customers and potential investors will require, as a precondition, the establishment and successful operation of local hydrogen

production capabilities within an order of magnitude of the target production scale. Construction of a >100MW facility is the next critical step for Australia to demonstrate capability and prepare the country as a major global RH exporter.

Implementation of the project would provide a pathway for a RH export market which could be viable within 5 years. With government support the project would:

- Supplant the need to import ammonia for the Moranbah facility
- Demonstrate to potential export markets, Australia's capability to meet demand
- Provide a demonstration vehicle for future investment in RH production in Australia
- Set a path to reducing CAPEX and OPEX for future projects by trialling and demonstrating potential technologies and operational capabilities at the plant
- Train and up-skill the workforce for the hydrogen supply chain and future projects
- Establish Australia as one of the first movers in the renewable hydrogen supply chain
- Attract large scale investment to develop the hydrogen economy in Australia
- Generate employment growth and export opportunities for Australia

The authors note that the development of an emerging renewable hydrogen industry is occurring globally, largely sponsored by Government investment. With recent announcements of EUR 9bn[1] in Government initiatives in Germany, USD 1.8bn in South Korea, GBP 12bn in the UK[2], Australian investment (approximately AU$370M) is being dwarfed by competitor countries. Without increased Australian investment in this sector, it is likely that key development in technology and manufacturing capability will be made overseas, significantly reducing the economic development available for the domestic sector in Australia. Strong Government support for the nascent renewable hydrogen industry has the potential to create a significant number of new jobs throughout Australia, particularly in regional areas.

The key project objective was to drive down the LCOH for RH production. The Commonwealth Scientific and Industrial Research Organisation (CSIRO) in the National Hydrogen Roadmap (2018) estimated the LCOH is approximately AU$5.50/kg[3] for 2020. This study has established that the cost can be driven down to AU$2/kg with government support, or AU$4 without. Forecast cost reductions should render like projects in the future economically feasible without government support, provided initial investment in early stage projects such as this project is undertaken.

Innovation in design was critical to reducing project cost. Current electrolyser capacity costs around AU$3M/MW installed for small scale, AC/DC integrated systems. Innovation through both scale and strategic thinking and step change engineering has led to:

- An innovative power system design that eliminates the need to convert power from DC to AC and back again. The result is a cost reduction of AU$1.2M/MW installed for this project

[1] Germany's hydrogen ambition begins to take shape: https://www.energyvoice.com/otherenergy/248528/germanys-hydrogen-ambition-begins-to-take-shape/#:~:text=The%20German%20government's%20%E2%82%AC9bn,to%2Dgas%20technologies%20across%20Europe.&text=The%20German%20plan%20sets%20a,TWh%20of%20hydrogen%20production%20annually.

[2] 10 Countries Moving Toward a Green Hydrogen Economy: https://www.greentechmedia.com/articles/read/10-countries-moving-towards-a-green-hydrogen-economy

[3] National Hydrogen Roadmap: https://www.csiro.au/en/Do-business/Futures/Reports/Hydrogen-Roadmap, page 55, figure 19

- Optimisation & improvement of BOP leading to a cost reduction of AU$0.1M/MW installed

Subtracting both cost reductions results in an electrolyser capacity cost of AU$1.3M/MW installed, a reduction of 44%.

In the future, it is anticipated that the cost may be reduced to <AU$1M/MW installed by further increasing the size of the stacks and number of stacks allocated to a given quantity of BOP.

2. Project Overview

In 2012, DNM commissioned a new world-scale integrated ammonium nitrate (AN) manufacturing facility in Moranbah, Queensland. This facility takes inputs of water, air and natural gas and converts them into hydrogen using a process called steam methane reforming (SMR). This hydrogen is then combined with nitrogen to create ammonia. The ammonia is then converted into nitric acid and then into the finished product of AN. AN from the facility is used in mining explosives, primarily to extract metallurgical coal in the local Bowen Basin region. Strong demand growth for locally-produced AN has already seen production from the plant increase to 115% of design and DNM is planning to increase capacity further.

Due to production capacity constraints, DNM is currently importing ammonia by road to meet AN production requirement, and further expansion will require additional ammonia. DNM has identified three options for sourcing the ammonia needed for the expanded AN production:

1. Increase the quantity of imported ammonia from domestic or overseas suppliers
2. Build a new SMR production facility at the Moranbah site to generate hydrogen from methane on site to produce ammonia
3. Build additional ammonia synthesis capacity utilising hydrogen supplied from a renewable hydrogen facility (RHF) to produce ammonia

The significant capital investment required for options 2 and 3 require competitive feedstock pricing (either natural gas or hydrogen), with the hydrogen price benefiting from the lower capital cost of a synthesis-only plant. Pre-feasibility analysis using published levelized cost of hydrogen (LCOH) indicated that hydrogen from a RHF would be uncompetitive, however with no data on large-scale RHF project costs in Australia and rapidly changing market conditions for both renewable energy and electrolysis equipment, DNM sought and received funding support from ARENA to complete a feasibility study on the potential for RH to displace conventional feedstock in this application.

The subject of the feasibility study is the design, construction and operation of a RHF in Moranbah, Queensland to supply the additional ammonia required for DNM's AN production expansion. To eliminate additional costs for transport and to maximise opportunity to share existing resources and infrastructure, the RHF would be located on land adjacent to DNM's existing SMR facility site. The RHF would be financed by third-party investors with DNM entering into a long-term offtake agreement for the RH.

DNM is considering two potential scales of expansion of its ammonia and hydrogen production capacity at Moranbah. In the first option, DNM will increase ammonia production by 135tpd equivalent to 23.8tpd of hydrogen and in the second option DNM will raise ammonia production by the equivalent to 18tpd of hydrogen. The study has been undertaken and costed on the basis of the 23.8tpd hydrogen production option and has been extrapolated to evaluate the 18tpd option.

The key design parameters evaluated during the feasibility study were the technology selection and sizing for renewable energy, hydrogen production and hydrogen storage to meet the DNM hydrogen demand requirements. The evaluation of these aspects is considered in sections 6, 7 and 9 of this report. The result of the feasibility design is a RHF comprising the following elements;

RHF Component	Description
Solar Farm Power Plant	240MW photovoltaic (PV) solar array, covering approximately 500Ha of land adjacent to the DNM facility and incorporating a novel DC/DC direct power input to the electrolysers.
Electrolysis Plant - H_2 Generation Facility - Cooling Water System - Auxiliary Power Supply	4 x 40MW electrolyser 'trains' distributed across the solar array to minimise cabling distance & electrical losses. Each train comprising 8 x 5MW electrolyser 'skids', for a total of 160MW, capable of producing 3.5 t/h of hydrogen at peak capacity (before drying losses). Each train includes electrolyser facility "balance of plant" equipment, involving coolers, purifiers, chillers, compressed air, fire protection etc. as well as a battery-backed AC power system for operational requirements and a fuel cell (4 x 120kW) for overnight standby operation.
Bulk Hydrogen Storage and Transportation - Tank Farm Compound - Auxiliary Power Supply	A single 54t compressed hydrogen storage facility centrally located to minimise hydrogen piping distance from trains and to DNM facility. 20MW, 10MWh AC battery system for auxiliary system operational requirements; gas and water pipe network for the facility; fire protection system; and a CEDI and RO plant for water purification.
Main Office Compound	Store, workshop, personnel facilities, office and main control room; fire protection system.
Common / Ancillary / General	Permits and approvals, civil works, fencing, general signage, training and overall facility control system allowing for the safe and efficient integration of all the above components.

Table 1: Summary of RHF Key Elements

The contents of this report outline the outcomes of modelling the technical and commercial feasibility of the RHF.

2.1 RHF Typical Operation Overview

This section describes the philosophy at a high level for the storage and transportation of hydrogen within the RHF.

On a typical morning, the PV modules (panels) mounted on the horizontal single-axis tracker frames are in stand-by mode facing east, waiting for the sunlight to be received on the panels. During the day, the electric motor-driven tracker mechanism rotates the panels to follow the sun. The tracker control system regulates the rotational speed and the angle of the panels based on the time of day to track the sun.

At the end of a typical day the panels have rotated to face the setting sun and are at the stop position facing west. The algorithm in the tracker control system will then determine

the time at which the panels start to rotate back to the starting position facing east. The electric motors, powered by batteries, will drive the tracker mechanism to rotate the panels back to the starting position ready for operation on the following day. The batteries for the electric motors are charged during the day so that they have full charge to rotate the panels during the night.

At times, the solar array could potentially create more power than is required by the electrolyser system. At such times, the DC/DC converter and the maximum power point tracker (MPPT) will only take power from the solar panels to service the required load. The voltage is fixed, as a condition of the electrolyser, as a result the resistance and current will vary to accommodate. Consequently, the potential additional power is not realised.

Each electrolyser will have a dedicated array (also called a block) of PV panels supplying power to the unit. The PV modules in the blocks will be connected in series to form strings. The strings will then in turn be connected to combiner boxes. Cabling for each string will be secured aboveground along the tracker support frames. The cabling to the combiner boxes will be buried. Similarly, the power cables from the combiner boxes to the DC/DC converters will be buried. Power from the DC/DC converters will be run to each electrolyser using cables and/or busbars.

Auxiliary Power System

Each electrolyser has a 'stack' where electrolysis occurs, as well as equipment that operates to supply the stack inputs and separate the produced hydrogen and oxygen outputs from water (called "balance of stack" or BOS). Equipment that can supply multiple electrolysers, such as water storage, cooling water, firewater etc. are typically described as electrolyser "balance of plant" or BOP.

Power for electrical BOS and BOP equipment will be generated in a dedicated PV solar array, where the DC current will be converted to AC before being distributed throughout the site via a ring main arrangement. The PV modules that generate power for the auxiliary system will also be connected in series into strings using aboveground wiring along the tracker support frame or a similar arrangement. Each string will be connected to combiner boxes using underground cabling. DC power from the combiner boxes is in turn fed to eight medium-voltage power stations (MVPS) distributed along the perimeter of the PV arrays using buried cable. Each MVPS is a modular container that integrates an inverter, a step-up transformer and switchgear so that the DC power fed into the MVPS is converted to medium voltage AC power. Each MVPS is connected to a ring main arrangement that feeds the medium voltage AC power to the various locations around the site in buried cables.

The ring main will supply medium voltage AC power to each of the electrolyser trains, the hydrogen storage tank farm, as well as to the main office/store compound. At each of these locations medium voltage AC power cables from the ring main will be connected to Ring Main Units (RMU) that have switchgear and a step-down transformer housed in a kiosk type of enclosure. Each RMU will step down the medium voltage AC power to a low voltage AC three-phase supply for the electrical equipment. Low voltage AC power is then connected to local distribution boards and Motor Control Centre (MCC) panels using buried cable. This

low voltage three-phase power is then in turn distributed around each location to the electrical equipment.

Backup Power

Due to the variable nature of the power source there will be times of inconsistent power supply (i.e. cloud cover). As the electrolyser stack system operates as a function of the power available in DC from the array, this fluctuation will not be an issue for hydrogen generation. However, equipment in the BOS and BOP may be damaged or not operate effectively with ramp down in this manner. Therefore, a string of 10MWh, 20MW containerised batteries will provide backup power to the ring main for up to 30mins at maximum operation. The containerised batteries will be located near the storage tank farm and will be connected to the ring main using buried cables. From the ring main, the cables connect to containerised medium voltage power stations (MVPS) similar to those used to convert power from the PV arrays to AC. However, these MVPS will convert the AC power in the ring main to DC and then store that power in the containerised battery packs.

In addition to having an AC power supply supplied via the ring main, the main office will also have its own small backup power system for maintaining control and computer equipment. A small rooftop solar array will provide DC power to a battery pack for storage of the solar power generated by the PV modules. An inverter will then convert the DC power from the battery packs to AC power to be used in the office building.

At each electrolyser train additional backup power for the overnight loads will be provided by a fuel cell power module (FCPM). Hydrogen gas will be supplied to each FCPM from the main transportation pipeline connected to the electrolyser train facility. Each FCPM will convert the hydrogen gas directly to DC current which is then converted to AC using an inverter.

Hydrogen Production and Transportation

At the start of a typical day, solar power will be generated by the solar farm as the sunlight is received by the PV modules. Electrical power will go to the electrolysers via DC/DC converters. Above a threshold power level hydrogen will start to be produced in the electrolyser stacks at 35bar, after which the hydrogen stream will be chilled and purified/dried. After chilling and purification, the hydrogen produced at each electrolyser train building will be at 34bar when it flows into the hydrogen header pipeline to be transported directly to the DNM tie-in point via a bypass line, or to the central storage vessels. The header pipeline will be buried for the most part and will have appropriate cathodic protection against corrosion.

Bypass Line

As hydrogen production ramps up in each electrolyser train the overall gas flowrate will increase. Hydrogen will flow via the bypass line and will have its pressure reduced to 32bar before flowing to a metering station and then to the DNM tie-in point. When hydrogen flow through the bypass line is below the required DNM offtake rate of 1t/h, additional gas will be provided to the metering station from the hydrogen storage vessels. This will typically occur when there is insufficient solar power to generate the required amount of hydrogen such as at night or when cloud cover reduces solar capacity.

Compression

At times of hydrogen production above what is required at the DNM tie-in point, excess hydrogen will be directed to storage where it will remain until it is needed. The hydrogen produced by the electrolyser trains will be received at the storage compound at 34bar and will be compressed before flowing to the main storage vessels to be stored at 250bar. There will be a total of 4 hydrogen compressor sets at the storage compound, 3 compressor sets will be used as production units and the fourth compressor will be available as a stand-by unit (i.e. a 3+1 configuration). The hydrogen storage and transportation configuration are shown in Figure 1.

As hydrogen flow from the electrolyser trains increases above the required rate in the bypass line only a single compressor set will start operating. The compressor sets will ramp up production using variable speed drives as the hydrogen flow from the electrolysers increases. When the first compressor set reaches its maximum flow capacity the second compressor set will be started by the plant control system. Similarly, when both the first and second compressor sets are operating at maximum capacity the control system will start the third compressor set and ramp up its operation as the gas flow from the electrolyser trains increases. The control system will regulate the operation of the VSD compressors based on the hydrogen flowrate from the electrolysers.

Storage

There will be a total of 54t of hydrogen storage capacity at the RHF. 53t will be stored at 250bar in 260 storage containers located in the storage compound. When hydrogen flow to DNM via the bypass line is less than the required 1t/h, hydrogen will be released from the bulk storage vessels to the 1t of buffer storage. Hydrogen pressure will be reduced from 250bar to 100bar and the gas stream will pass through a let-down cooler before it enters the buffer storage comprised of 18 storage containers. Hydrogen flowing from the buffer storage will be reduced in pressure from 100bar to 32bar and will be cooled in another let-down cooler before passing through the metering station and finally on to the DNM tie-in point.

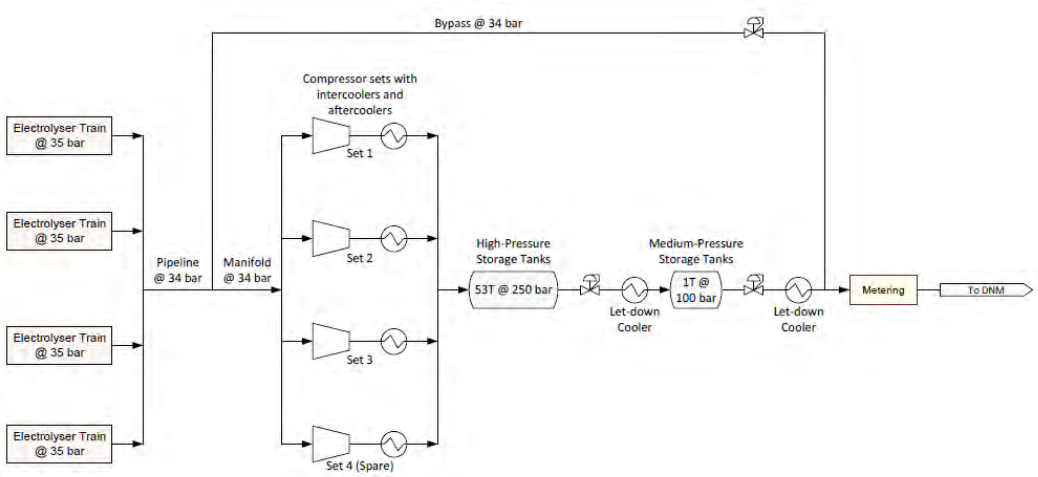


Figure 1: Hydrogen Storage and Transportation

2.2 RHF Modelling Overview

Initial modelling to determine the equipment size range for the RHF resulted in an electrolyser size and solar farm of approximately 160MW and 230MW, respectively. This model only considered the yearly demand requirement for DNM of 23.8tpd all year round.

These sizes were then applied as the basis for the more in-depth model utilised for this feasibility study. This model applies multiple variables to produce a viable solution for an operating RHF that meets the DNM demand requirements. The most important constraint set by DNM was for continuous (24/7) hydrogen supply.

To optimise the design, alternate equipment configuration in the solar farm and electrolysis trains were assessed and the capacity of the hydrogen storage was varied to provide the optimal configuration for the corresponding capacity of the electrolyser and solar. It is noted that this feasibility study has produced one solution to a multiple variable problem and that further optimisation is still available.

The model, at a high level, relies on three main variables: solar, electrolysis and hydrogen storage. Each variable is a function of the others and adjusting one results in a change in the other two. In turn, each of these variables contain additional variables that adjust the outcome. For example, solar output is contingent on the location of the install site, which is itself a function of weather patterns, latitude, solar irradiance, etc. This gives basis to the necessary complexity of modelling and the multitude of potential solutions. Each of these potential solutions has an associated cost. As a multi-variable analysis, changing one variable, for example: reducing the hydrogen storage, does not automatically lead to a reduction in overall cost. This is because as there is a reduction in the storage size, more electrolysis and solar capacity is required to accommodate the shortfall of power in winter and inclement weather.

Ultimately, the model provides a solution which establishes engineering feasibility – i.e. that an RHF can satisfy DNM's needs for an upgrade of their ammonium nitrate plant. *At the next stage of this project, further value engineering will improve the solution to support meeting the requirements of the owner, financiers, and funders.*

3.1 Project Cost Estimate Summary

The project cost estimate presents a summary of the feasibility-level capital costs. Estimate accuracy of ±20% has been sought during the feasibility study, however not all elements of the estimate reach this level.

The estimate includes the design and construction of:

- 240MW Solar Power Plant, approximately 500Ha in total area
- 4 Electrolyser trains totalling 160MW design capacity (3.5t/h peak hydrogen flow)
- 54t bulk hydrogen storage facility
- Hydrogen compression and metering station
- Hydrogen transportation pipelines
- Central main office and store compound

The estimated capital cost for the RHF project was calculated to be **AU$674.43M**, assuming Australian Dollar exchange rates of AUD/USD = 0.70, and AUD/EUR = 0.61. Based on the design scope used during the Feasibility Study, two different cost breakdowns of the ±20% capital estimate are shown below.

3.1.1 RHF Components

	AU$M	%
Solar Farm	239.42	35
Electrolyser Trains	213.90	32
Pipelines/Storage	111.61	17
Ancillary & General	50.70	7
EPC Margin	25.36	4
Contingency	33.44	5
TOTAL	**674.43**	**100**

Table 2: RHF Main Component Costing

3.1.2 Materials and Labour

	AU$M	%
Materials & Equipment	437.91	65
Services & Labour	177.72	26
EPC Margin	25.36	4
Contingency	33.44	5
TOTAL	**674.43**	**100**

Table 3: RHF Material and Labour Costs

3.1.3 Contracting Model

To reduce the overall cost, the contracting model assumed for the CCE calculation was an Engineer, Procure & Construct Management (EPCM) model where certain key capital equipment is free-issued to an EPC contractor for installation and commissioning. It was determined that the total value of free-issued equipment is AU$362.07M (or approximately 54% of the CCE total, this includes equipment suppliers auxiliary and staff cost) and the profit margin applied by the EPC contractor to the remaining project scope that they will be responsible for is 10%, which equates to AU$25.36M.

The modular nature of the solar farm, electrolysis trains and bulk storage lends itself to this contracting model. The cost for modular and prefabricated items is a very large proportion of the total. This model does introduce higher investor risk as it is very likely EPC vendors will seek to limit liability on the performance of the various equipment items. As the overall facility performance relies on integration of all elements, this will affect the value and effectiveness of any performance guarantee for the facility.

The RHF owner(s) would need to balance this risk versus the financial benefit of lowering capital investment by avoiding EPC margin. This makes it more important for RHF owners to understand the potential performance risks and would likely limit the equipment manufacturing suppliers to those with strong warranties, market reputations and financial backing.

4. Project Overview – Plant Design and Economics

ANT's engineering and design team has developed an innovative RHF that is capable of continuous supply of 24tpd of RH to DNM. The PEM-based design comprises a 240MW solar farm with 160MW of electrolysis capacity dispersed within the solar farm as 4 x 40MW trains to optimise scale and minimise losses. The team has developed a novel storage and transport solution to ensure that the system, allowing for seasonality, meets DNM's requirements.

The proposed design can be scaled to meet either ammonia demand option being considered by DNM (18tpd or 24tpd of hydrogen). The electrolyser plant design and footprint are shown in Appendix 1 for the 24tpd and 18tpd RHF. The 18tpd RHF can be built within the 24tpd footprint, providing space for future expansion.

Due to the absence of any premium in the domestic market for ammonia or AN produced from renewables, RH must be supplied to DNM and ammonia manufactured at a price competitive with the non-renewable import alternative. Ammonia imports can be delivered without further capital investment by DNM, so RH must be supplied at a price low enough to provide a return on capital expenditure required for manufacturing ammonia from RH. Based on the forecast delivered imported ammonia price, DNM modelling determined that investment in additional ammonia capacity is only justified if the cost of hydrogen supplied to DNM is equal to or less than AU$2/kg. The feasibility of investment in the RHF was therefore assessed utilising a target price for RH of $2/kg.

The validation of ANT's design and engineering within the study has allowed for a preliminary economic analysis to be undertaken. Table *4* shows the cash flow analysis for the two production scenarios while Table *5* shows the potential capital costs and project returns for 18tpd and 24tpd options under three capital cost scenarios (the base estimate without contingency ±20%).

H2 Production		Average Revenue	Average OPEX	Average Sust. CAPEX	Average Cash Flow	LCOH	Payback
(tpd)	(tpa)	(AU$M/y)	(AU$M/y)	(AU$M/y)	(AU$M/y)	($/kg)	Years
18	6,306	16.6	12.6	1.1	2.9	4.31	32
23.8	8,448	21.6	15.7	1.3	4.3	4.09	30

Table 4: Projected Operating Cashflows

H2 Production	Capital Case	Total installed CAPEX	Average Cash flow	Equity Funding	Government support required		NPV (@4%)	LCOH	Payback
(tpd)	(%)	(AU$M)	(AU$M)	(AU$M)	(AU$M)	(%)	(%)	($/kg)	Years
18	-20%	395	2.9	166	229	58	105	3.75	30
18	Base	494	2.9	200	294	60	125	4.31	32
18	+20%	593	2.9	233	360	61	145	4.87	34
23.8	-20%	513	4.3	225	288	56	144	3.47	29
23.8	Base	641	4.3	374	395	51	176	4.09	30
23.8	+20%	769	4.3	289	480	62	201	4.53	42

Table 5: Projected Returns from Best & Worst Cases (+/-20% of Base Cost of $641 M)

The economic analysis has found that under both best and worst cases the RHF is cash flow positive and generates a positive NPV. The large size of the project allows for operational fixed costs to be spread over higher production, resulting in lower fixed costs per tonne and also benefits from lower unit equipment costs due to purchasing scale discounts and integration opportunities. Building a dedicated solar farm has the impact of essentially capitalising future energy consumption, resulting in much higher capital costs than grid-connected concepts, but a low enough OPEX cost to be cash positive. The relatively low capacity factor (CF) of the electrolysis facility at 38% also increases upfront capital costs as the scale of electrolysis and hydrogen storage is increased.

The large upfront capital expenditure and limited cashflows mean payback periods are longer than 25 years. For the current project to move forward, significant government support is required to address the market failure and help the nascent Australian renewable hydrogen industry that is vital to meet the future export opportunities identified by ACIL Allen[9], COAG – National Hydrogen Strategy[10] and the CSIRO National Hydrogen Roadmap[11]. If progressed, the project would demonstrate an industrial scale RH production capability needed to establish local supply chains, skills and jobs to set up Australia as a leader in the future RH export market. At the future target price of ¥330/kg[12] [13](AU$4.56/kg) for H_2, an RHF could be established with investable returns for the private sector without government support.

The scenarios outlined in Table *4* and Table *5* assume:

- Post tax 5% IRR on equity funding
- Depreciation method of 15% on diminishing value
- Average revenue based on $2/kg indexed at 2% of the increase in OPEX over 25 years
- Average annual OPEX is the total OPEX averaged over 25 years

[9] ACIL Allen Consulting for ARENA, Opportunities for Australia from Hydrogen Exports, August 2018: https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf, page 3, box 1.1.
[10] COAG – Australia's National Hydrogen Strategy: https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf, Page X
[11] National Hydrogen Roadmap: https://www.csiro.au/en/Do-business/Futures/Reports/Hydrogen-Roadmap, Page 10 - 2.2 Policy and regulation
[12] METI - Basic Hydrogen Strategy Japan (Key Points): https://www.meti.go.jp/english/press/2017/pdf/1226_003b.pdf, Page 20 - 4.1.
[13] Nagashima japan hydrogen 2018: https://www.ifri.org/sites/default/files/atoms/files/nagashima_japan_hydrogen_2018_.pdf, Executive Summary

4.1 Project Major Milestones

The feasibility study identified the key activities required to implement the project. The draft schedule shows the project will take 50 months or just over 4 years to progress from the current design stage to operation.

The main (high-level) tasks on the critical path for the project are:

1. Funding and financing agreements
2. Primary Permits & Approvals
3. Engineering Design of the Solar, Electrolysis and Hydrogen Storage elements
4. Procurement & Installation of Electrolyser skids and Balance of H_2 System Equipment
5. Commissioning of Electrolyser Plants and Distributed Control System

The modular nature of the solar farm and electrolyser trains allows work to be progressively completed. Each solar 'block' and electrolyser train can be independently built and commissioned. Depending on the scheduling and integration requirements between modules, staged commissioning could be considered allowing partial RH supply 6 months or more in advance.

Major Project Milestone	Months from Start
Secure financial approval for and start FEED Study	0
Coordinator General's approval of final IAR	14
Contracts in place for Offtake, Construction and Financing	18
Permits & Approvals (Primary) and Final Financial Approvals	19
Site Mobilisation commences	21
Engineering complete for main units (Solar Plant, H_2 Generation, H_2 Storage & Compression)	22
Engineering complete for Ancillary and AC Power Systems	23
Permits & Approvals (Secondary) and Development Permits granted	24
Delivery to site of Solar Panels, Frames and Trackers	28
Delivery to site of first Electrolysis modules	34
Delivery to site of H_2 storage containers & compressors	34
Delivery to site of BOP and Ancillary Items	36
Main Office & Store Compound construction complete	36
Block 1 Solar Farm Installation complete	36
Block 1 Solar Farm Commissioning complete	38
Hydrogen Transportation and Storage Installation complete	39
Block 4 Solar Farm Commissioning complete	41
Block 1 Electrolysis Plant Installation complete	41
Hydrogen Transportation and Storage Commissioning complete	42
Block 1 Electrolysis Plant Commissioning complete	44
Delivery to site of final Electrolysis modules	46
Block 4 Electrolysis Plant Installation complete	47
Block 4 Electrolysis Plant Commissioning complete	50
Final handover of entire facility	50

Table 6: Major Project Deliverables

5. Overall System Design Parameters

The below tables outline the major design considerations for the RHF.

5.1. Solar Farm Power Plant

Assumptions
Ground coverage ratio (GCR) of 0.3
Soils = sandy clay, 100% driven piers, 10% rectification
Wind region A4
Soiling loss of 1% (Dirt/dust build up)
Wiring loss of 1.5%
Thermal loss factor of 25 W/m^2K
Solar panel degradation of 2.5% maximum capacity in first year, 0.45% every year after

Table 7: Solar Facility Assumptions

Parameters & Configuration
240MW capacity
202MW dedicated to electrolysis and 38MW for auxiliary AC systems
Sunpower Bifacial P5-500W power module for solar output data and array layout
Design based on average (P50[15]) irradiance data modelled using solar array power output program, PVsyst
Single axis tracking (2P, two portrait panel configuration)
Panel mounting system to be ground mounted with driven piles
28 modules per mounted string (typical string dimensions: 26.7m x 4.3m)
2 strings per table
Direct DC/DC connection to electrolyser facility (640-880V)
225 tables per DC/DC buck converter
2 x DC/DC buck converter per 5MW electrolyser skid
Tracker rotation -55°/+55°
Converter feeders installed in ventilated underground trenches
PV string cables installed unenclosed and shaded
8 x 4.2MW inverter to provide auxiliary AC power during operation

Table 8: Solar Facility Parameters

[15] P50 is the term used by solar irradiance company Solargis (from whom ANT purchased the solar irradiance data for the Moranbah site) which calculates the most likely solar irradiance for a given site from 10 years of historical solar data. For further information refer to the following: https://solargis.com/blog/best-practices/how-to-calculate-p90-or-other-pxx-pv-energy-yield-estimates

5.2. Electrolysis Plant

Assumptions
Required average feed from RHF – 24tpd (6tpd per train)
Constant hydrogen feed to DNM (means zero hours per year of zero hydrogen flow)
3% hydrogen loss due to hydrogen drying
Electrolyser stack degradation of 0.4% every year
>64,000 ± 15,000 hours operating life, 24 years life[16]
Nominal stack efficiency of 48.3 kWh/kg H_2 start of life, 53.1 kWh/kg H_2 end of life

Table 9: Electrolysis Plant Assumptions

Parameters & Configuration
PEM-based 160MW capacity, separated into 4 x 40MW electrolyser trains
Design maximum flow rate of 3.4t/h for Hydrogen and 27.2t/h for Oxygen[17]
Each train consisting of 8 x 5MW electrolyser skids
Each skid comprising of 2 x 2.5MW stacks and one balance of stack skid
Balance of plant and power equipment sized for 3%-120% production rates
9 air coolers per train to regulate stack temperature
Building HVAC system to maintain preferred equipment ambient temperatures
Trains centrally located within solar farm arrays to minimise cable runs
Local DI water storage (1,170kL) for each train
Fire suppression with separate diesel water pump system for each train
120kW Fuel Cell at each train to service overnight auxiliary loads

Table 10: Electrolysis Plant Parameters

5.3. Bulk Hydrogen Storage

Assumptions
40 Deg.C delivery temperature to DNM
Cyclic life of EKC11880 container is >10,000 cycles, 27 years life[18]

Table 11: Bulk Hydrogen Storage Assumptions

Parameters & Configuration
A total of 54t of useable hydrogen storage. 53 workable tonnes at 250bar & 1 workable tonne at 100bar within EKC11880 hydrogen storage containers. Storage located at a single consolidated central tank farm
4 x 2,235kW VSD hydrogen compressors (3 x 80% duty + 1 Standby)
35bar compressor inlet pressure, 250bar compressor outlet pressure
32bar supply pressure to DNM (250barg let down via 100barg storage)

Table 12: Bulk Hydrogen Storage Parameters

[16] Assumes operation above 50% electrolyser capacity of 3244 hours
[17] Assumes PEM electrolyser maximum capacity of 120% after 3% hydrogen drying loss
[18] Assumes 1 cycle per day

6. Basis for Selection of Technology and Key Design Elements

6.1 Renewable Resource Selection

To produce renewable hydrogen at the required quantity, a large amount of low-cost renewable energy is required. Energy options considered for the project location in Moranbah, Queensland were wind, solar and hydro.

The Australian Energy Market Operator (AEMO) has conducted research into the potential for renewable energy zones in Australia. The results are outlined in Figure 2[19] showing wind (left) and solar (right) availability, with the highest rating potential for both solar and wind farm indicated in green.

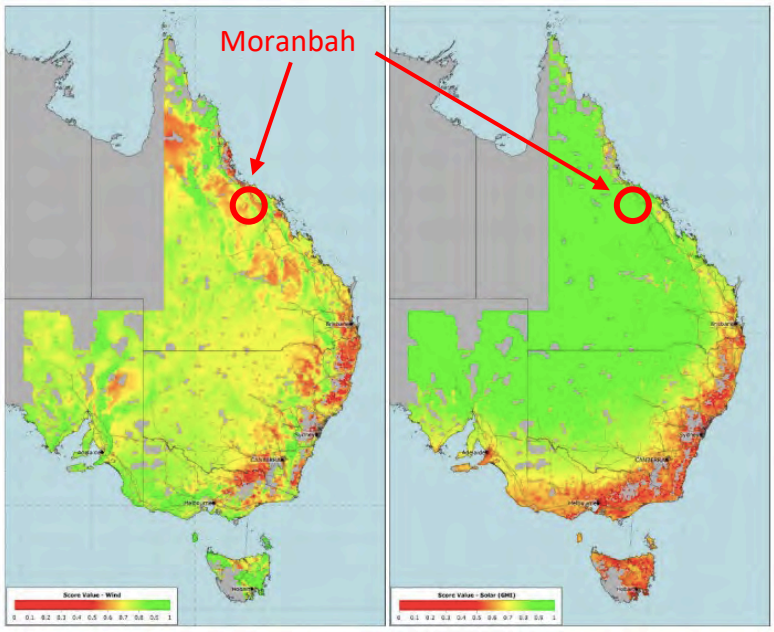


Figure 2: Assessed resource availability for wind (left) and solar (right)

Using Figure 2 as an indication for the viability of both renewable options, AEMO has identified Moranbah as having a high renewable potential for solar and a moderate potential for wind. The potential for solar and wind was then evaluated using local weather information from the Bureau of Meteorology (BOM) to determine the capability of producing the required power for the RHF.

[19] AEMO Report on Renewable Energy Zones in Australia: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/ISP-Appendices_final.pdf

6.1.1 Wind Analysis

Hourly BOM wind data from the Moranbah airport monitoring station for the years 2012-2019 was averaged for each hour in a 24-hour period to determine the daily wind profile. The data was taken at a height of 10m and the wind speed is then extrapolated to two typical turbine heights of 37.5m and 100m. This is intended to reflect the wind speeds at those hub heights and to also determine at what times the maximum wind speeds occurred.

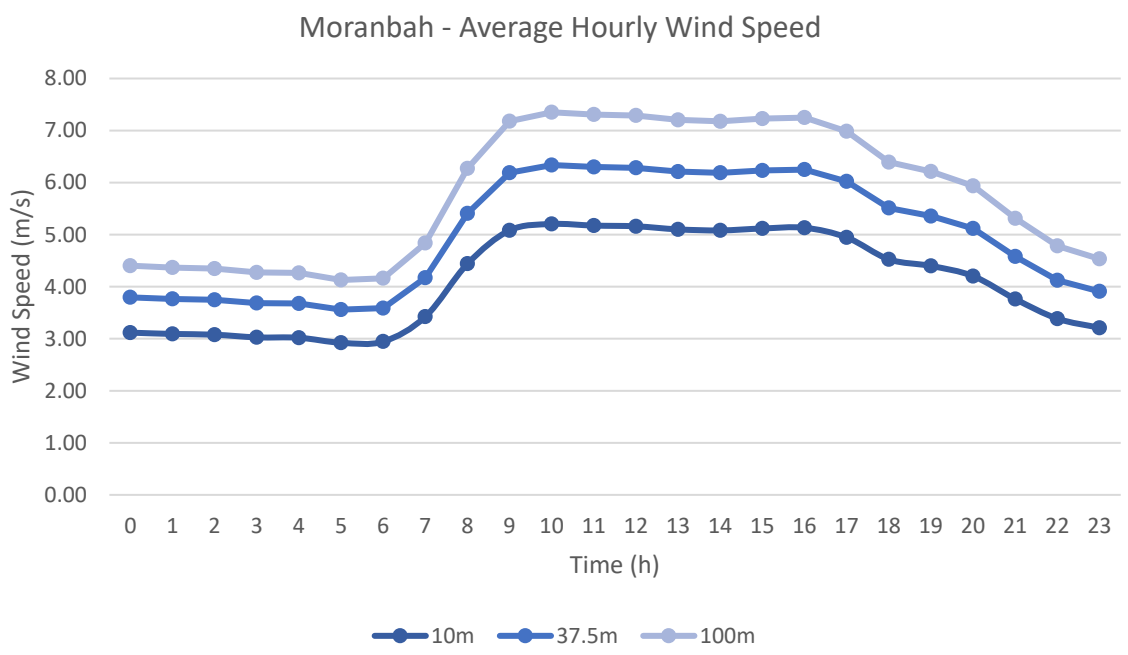


Figure 3: Wind Speed Profile for Moranbah at Hub Heights of 10m, 37.5m & 100m

It is noted that maximum wind speeds occur from 9am to 5pm, overlapping the expected period of high solar power generation. Therefore, there would be minimal offset in energy generation between wind and solar supplies. As the average overnight wind speeds are quite low, the benefit of combined wind and solar generation will be limited and will only make sense if the wind power CF is high.

To determine the wind power CF, three turbines of different output magnitude, XANT 100kW, Norwin 200kW (37.5m hub height) and Senvion 4.2MW (100m hub height), were investigated to determine the average hourly power output for the Moranbah site (per figures 4 - 5).

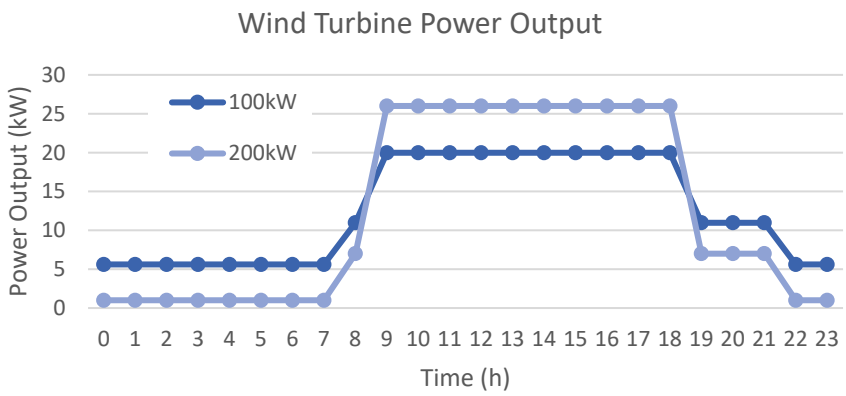


Figure 4: Power Output for XANT 100kW & Norwin 200kW Wind Turbines

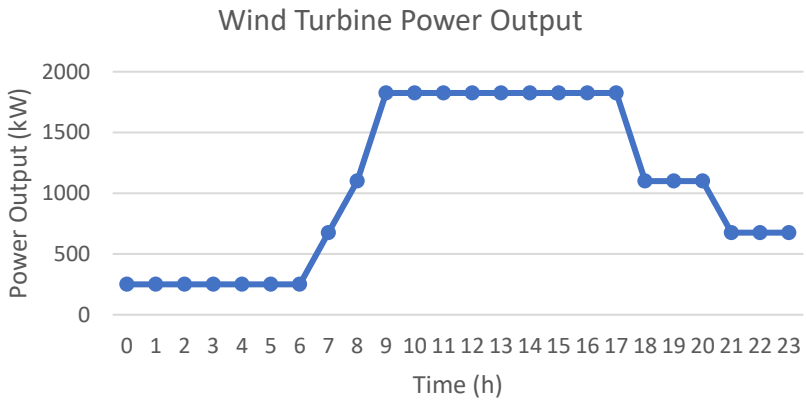


Figure 5: Power Output for Senvion 4.2MW Wind Turbine

The maximum average output compared to the rated capacity for the turbines are as follows:

- XANT 100kW Turbine: 20% of rated capacity
- Norwin 200kW Turbine: 13% of rated capacity
- Senvion 4.2MW Turbine: 43% of rated capacity

The assessed CF of the wind resource at Moranbah can be observed in Table *13*. The CF is calculated by dividing the actual power produced by the wind turbine by the total potential generating power if the wind turbine were to run at rated capacity for 24 hours each day.

	CF (%)	**CF Outside Peak Hours (%)**
XANT	12%	5%
Norwin	6%	1%
Sevion	25%	9%

Table 13: Turbine Power CF as Function of Total Potential Power

6.1.2 Solar Analysis

With advice from ANT's collaborator Terabase, solar analysis was carried out utilising hourly Global Horizontal Irradiance (GHI) data from Solargis for a Typical Meteorological Year (TMY) calculated from 12 years of solar data (2007 to 2018). Figure 6 compares the total amount of irradiance observed in each year within the data set. Minimum solar irradiance occurred in 2010 and maximum solar irradiance in 2015. The P50 data represents the average or "typical" year over the data set. Solargis data was chosen as it provides a more conservative solar irradiance output for the region of Moranbah, allowing for a design case with a greater factor of safety.

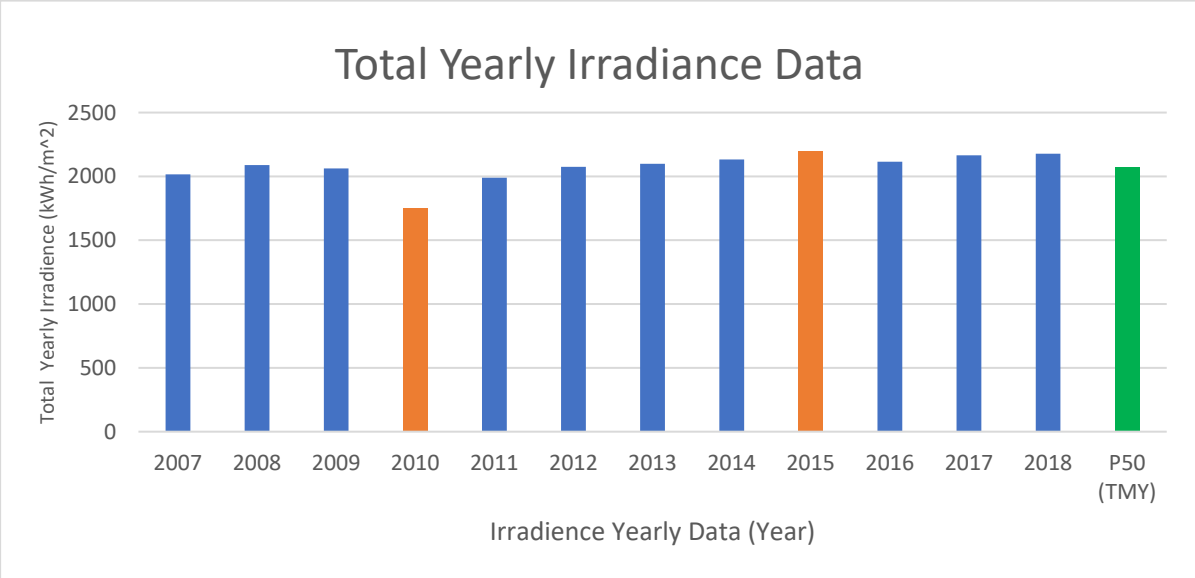


Figure 6: Total Yearly Irradiance Data

Figure 7 demonstrates the yearly, summer and winter average irradiance each hour for a typical day (TMY) over a year. It can be observed that available solar irradiance occurs from 5am to 6pm, with slightly less in winter and slightly more in summer.

The TMY data was then run through solar panel power output program, PVsyst, utilising 500W Sunpower panels and single axis tracking. Figure 8 was constructed for the output of the estimated 202MW solar array for the maximum, minimum and average yearly data to demonstrate the potential variability of the solar resource.

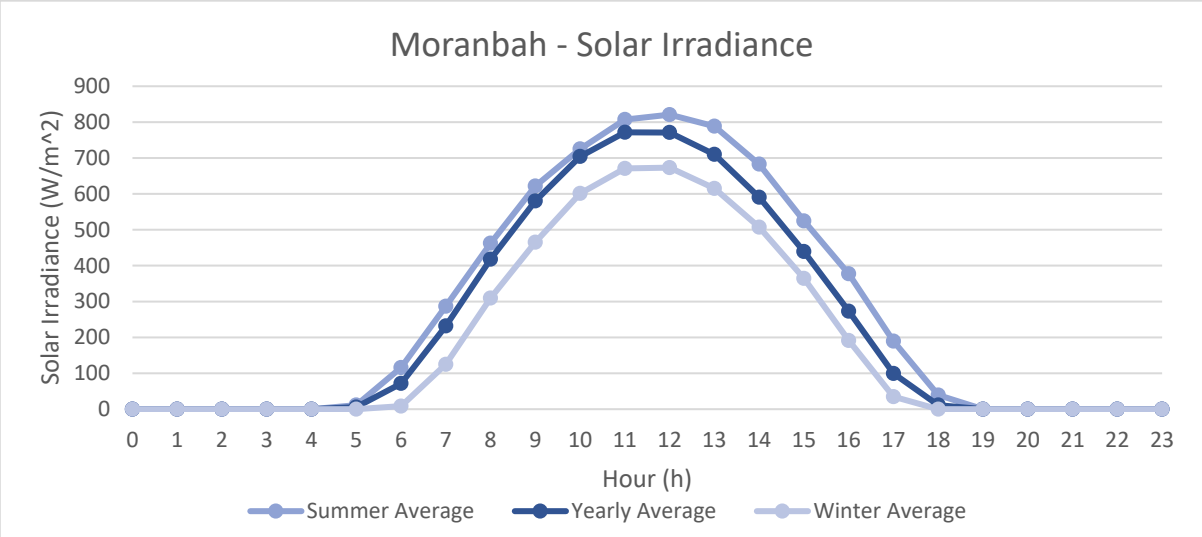


Figure 7: Moranbah – Solar Irradiance

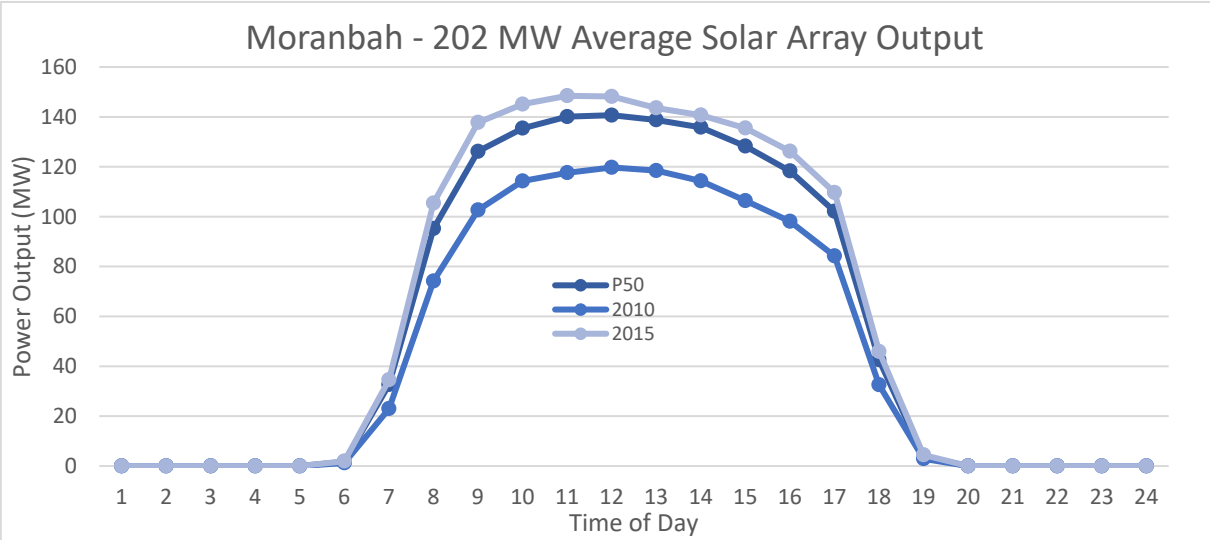


Figure 8: 202MW Average Solar Output

The assessed CF of the solar resource at Moranbah was calculated by dividing the daily average power produced by the solar farm by the total potential generating power if the panels generated at maximum power for 24 hours in the day (24 x 202):

	CF (%)
P50 (TMY)	28%
2015 (Max)	30%
2010 (Min)	23%

Table 14: Calculated Solar CF in Moranbah

6.1.3 Hydro-Electric Power Generation (Hydro) Assessment

The following provides a preliminary assessment of hydro-electric power generation (hydro) as a power source for the Renewable Hydrogen Facility (RHF).

Currently there are no hydro plants in Moranbah. The closest major dam to Moranbah is the Burdekin Dam which is approximately 170km to the northwest of the RHF site.

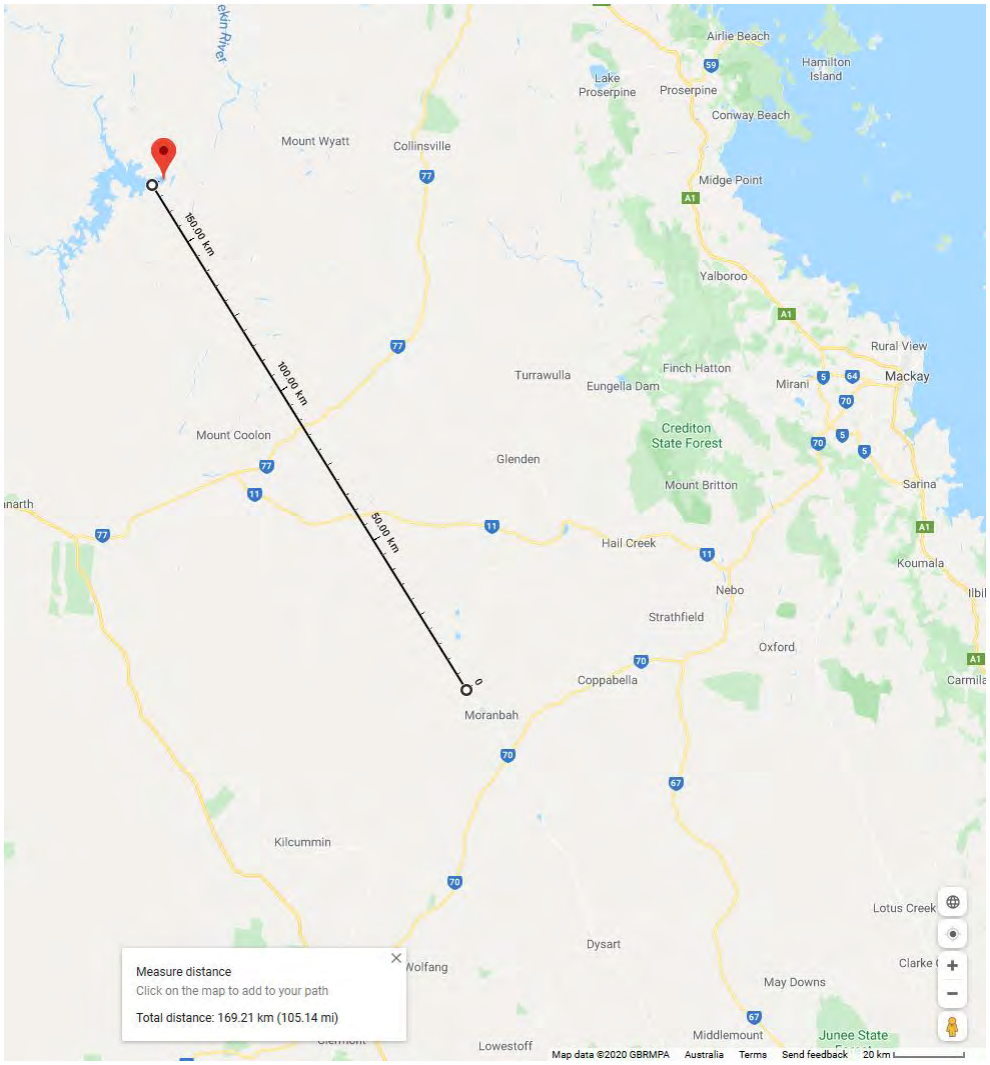


Figure 9: Burdekin Dam

The Burdekin Dam is primarily used for the purpose of irrigation. Stanwell Corporation has begun a feasibility study into a proposed 37MW hydroelectric power station below the Burdekin Dam wall. Stanwell Corporation has recently completed a pre-feasibility study which has confirmed there are no fatal flaws surrounding the concept of a hydroelectric power station on North Queensland's Burdekin Falls Dam[21]. The Queensland government has announced plans to potentially develop a hydro power station in future subject to the

[21] Queensland's Snowy 2.0 and Burdekin Hydro Plans Power Ahead: https://theurbandeveloper.com/articles/hydro-electric-power-station-plans-burdekin-falls-dam

completion of a business case. The 125GWh proposed for the Burdekin project is less than 1/3 of the power required for the DNM RHF.

Utilising hydro power would require power to be distributed from the dam to the RHF. A key issue is that there is currently no transmission infrastructure connecting the Burdekin Dam to the High Voltage (HV) electricity network in Queensland.

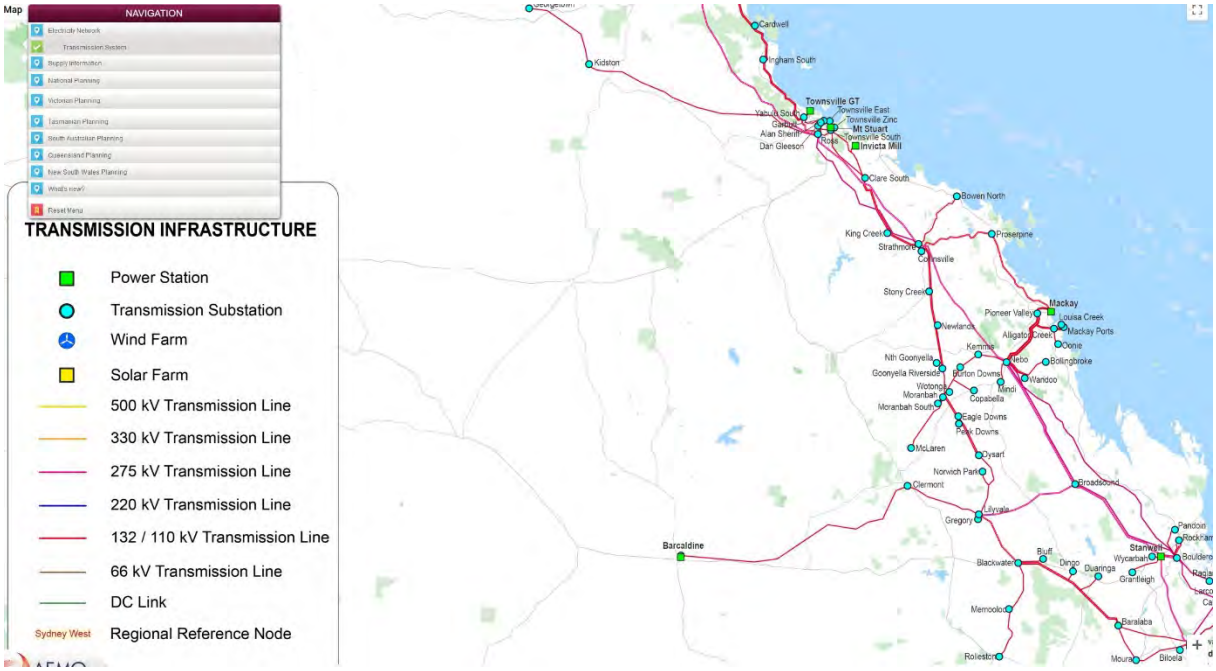


Figure 10: Transmission Infrastructure

The closest tie-in points would be King Creek or Strathmore as shown in the diagram above from AEMO[22].

With no hydro power plant in operation yet and no HV transmission lines connecting to the grid, Burdekin Dam is currently not an option to provide power to the RHF.

Pumped Hydro

Currently there are no pumped hydro plants in Moranbah. The Australian National University[23] has identified potential sites for pumped hydro installations in the hills to the east and north-east of Moranbah but currently there are no plans to construct these installations. The potential sites are identified in Figure 11[24], all of which are at least 90km away from the site.

[22] AEMO Map:
https://www.aemo.com.au/aemo/apps/visualisations/map.html
[23] ANU Global pumped hydro atlas:
http://re100.eng.anu.edu.au/global/index.php
[24] Australian Renewable Energy Mapping Infrastructure:
https://nationalmap.gov.au/renewables/#share=s-oDPMo1jDBBtwBNhD

With no firm plans or approvals in place for the construction of these possible pumped hydro facilities near Moranbah, they are not considered a credible option to provide power for the RHF in the timeframe forecast for the project.

It is noted that due to the location of the Moranbah facility, all potential hydro power concepts would be grid connected, therefore incurring connection and transmission costs.

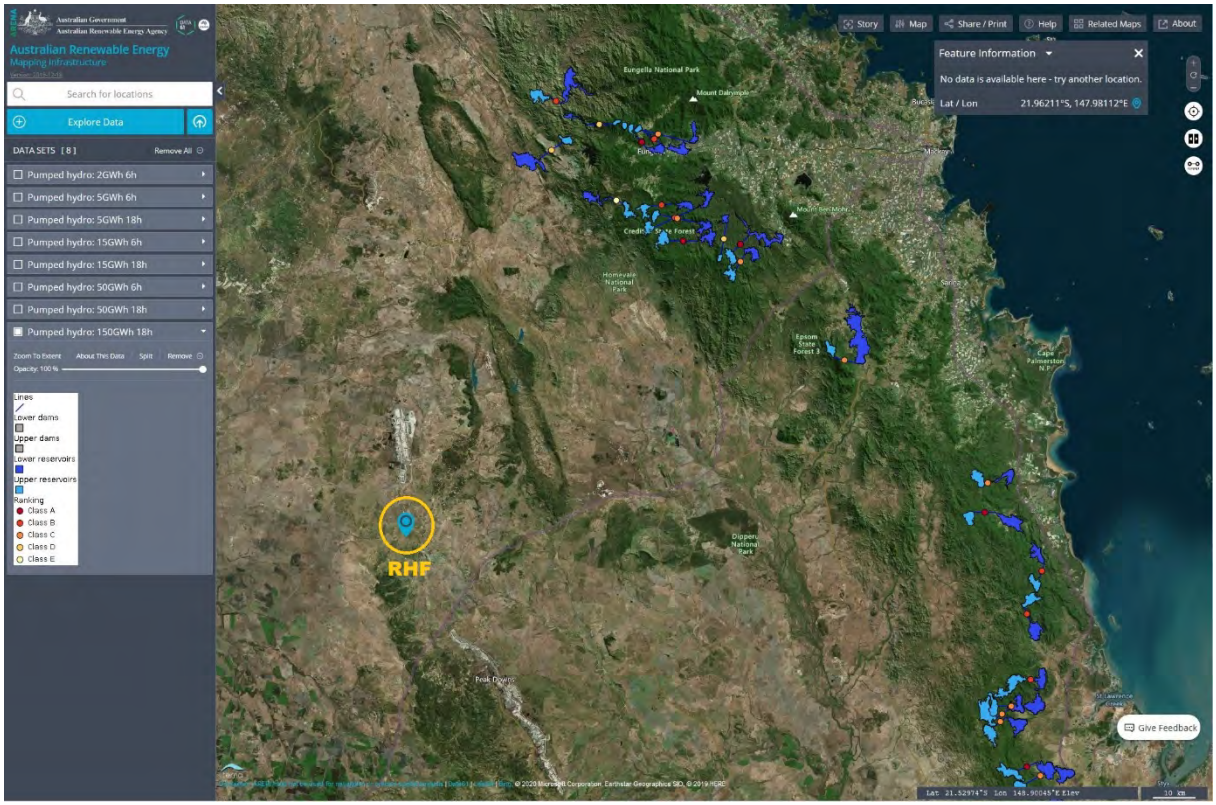


Figure 11: Potential Pumped Hydro Sites

6.2 Energy Supply Options Comparison Summary

Of the three potential renewable energy sources for the project, only two were considered feasible. Hydroelectricity is unable to provide BTM power for the RHF because there are no significant (>50MW) hydro power plants near Moranbah.

Wind and solar renewable resources both have potential. However, the forecast CF of a solar farm is 3% higher than of a wind farm in the same location. Dividing the solar CF by the wind shows that 12% less solar generating capacity is required for the same average daily power production.

There is a minor benefit in having wind power to provide power at night. However, the low evening CF of the wind farm (9%, using the Sevion turbine as an example), means that this would only provide benefit if the overall capital cost of the wind capacity is similar to, or lower than that of the solar capacity.

Market data[25] on current installed costs for onshore wind installation indicates a total installed cost of $AU1.85/W. This compares unfavourably to the total installed cost for single-axis solar PV of $AU1.20/W. Solar PV was therefore selected as the preferred renewable energy source for the project.

	Wind	Solar
Average CF	25%	28%
Install Cost	AU$1.85/W	AU$1.2/W

Table 15: Cost and Efficiency Comparison of Wind and Solar

These parameters indicate that the levelized cost of power from wind would be 70% more expensive in this location than a solar only solution.

[25] AEMO – 2019-2020 Forecasting and Planning Scenario Inputs and Assumptions Report: https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/2019-20-forecasting-and-planning-scenarios-inputs-and-assumptions-report.pdf?la=en, page 36

6.3 Solar Panel Mounting – Fixed Versus Tracking

The decision of whether to have fixed or tracking solar panels was based on a cost-benefit analysis. Tracking systems increase the amount of power generated from each panel; however, they also increase the capital cost of construction due to the need for motors and moveable frames.

Single-axis tracking (SAT) was chosen for the solar array and tables *16* - *18* outline the justification as a comparison to a ground fixed tilt (GFT) configuration to optimise hydrogen production. Table 16 indicates that for the same size system, approximately 100GW per year of additional energy is available for RH production.

Table 17 and Table 18 outline the results of the financial analysis conducted by Terabase with a simulated electricity tariff of 3.5c/kWh and 5c/kWh. The tracking system provides a higher financial return compared to the GFT in both cases.

Energy Output	GFT	Tracker
System Size (MW peak)	220,800	220,800
Energy Yield (kWh/kW peak)	1,852	2,284
First Year Yield (GWh)	408	504

Table 16: 220MW Solar Array Yield

Results (3.5c electricity tariff)	GFT	Tracker
IRR	6.3%	8.9%
LCOE (USD $/kWh)	0.0436	0.0393
NPV (USD $M)	-$7.82M	$4.73M

Table 17: Financial Model Results based on electricity tariff of 3.5c/kWh

Results (5.0c electricity tariff)	GFT	Tracker
IRR	16.9%	21.2%
LCOE (USD $/kWh)	0.0436	0.0393
NPV (USD $M)	$38.70	$62.11M

Table 18: Financial Model Results based on electricity tariff assumption of 5.0c/kWh

Note: Fixed verses tracking review was conducted early in the study and considered 220MW of generation utilising 430W Sunpower solar panels. Results would be similar using the final project configuration.

7. Review of Electrolyser Technologies and Selection

Hydrogen generation can be achieved by different pathways which fall into 4 broad categories, namely electrochemical, chemical, biological and thermal. Many technologies are in early development. Only the proton exchange membrane (PEM) and alkaline electrolyser technologies are currently beyond Technology Readiness Level (TRL) 7 and commercially available. Accordingly, and in accordance with the project timeframe, only PEM and alkaline were considered for the RHF.

7.1 PEM and Alkaline Systems Overview

The following summary by the International Energy Agency[26] explains both alkaline and PEM technologies.

"Alkaline electrolysis is a mature and commercial technology. It has been used since the 1920s, in particular for hydrogen production in the fertiliser and chlorine industries. The operating range of alkaline electrolysers goes from a minimum load of 10% to full design capacity. Several alkaline electrolysers with a capacity of up to 165 megawatts electrical (MWe) were built in the last century in countries with large hydropower resources (Canada, Egypt, India, Norway and Zimbabwe), although almost all of them were decommissioned when natural gas and steam methane reforming for hydrogen production took off in the 1970s. Alkaline electrolysis is characterised by relatively low capital costs compared to other electrolyser technologies due to the avoidance of precious materials.

PEM electrolyser systems were first introduced in the 1960s by General Electric to overcome some of the operational drawbacks of alkaline electrolysers. They use pure water as an electrolyte solution, and so avoid the recovery and recycling of the potassium hydroxide electrolyte solution that is necessary with alkaline electrolysers. They are relatively small, making them potentially more attractive than alkaline electrolysers in dense urban areas. They are able to produce highly compressed hydrogen for decentralised production and storage at refueling stations (30–60 bar without an additional compressor and up to 100–200 bar in some systems, compared to 1–30 bar for alkaline electrolysers) and offer flexible operation, including the capability to provide frequency reserve and other grid services. Their operating range can go from zero load to 160% of design capacity, so it is possible to overload the electrolyser for some time, if the plant and power electronics have been designed accordingly.

[26] The future of Hydrogen Report prepared by the IEA for the G20, Japan: https://www.iea.org/reports/the-future-of-hydrogen, page 43,44

7.2 Comparative Analysis – PEM vs Alkaline

The advantages and disadvantages of PEM and alkaline in a general context is presented in section 7.1. This section sets out the results of an analysis of the two potential systems in the context of the DNM ammonia plant project. Specifically, the two systems are compared based on the DNM hydrogen requirement of 23.8tpd while being cost effective to deliver the desired selling price of AU$2/kg to DNM. Key inputs to the analysis were:

- Energy efficiency (kWh/kg H_2 produced)
- Degradation (efficiency loss with time)
- Electrolyser operational utilisation and CF
- Current CAPEX cost of equipment ($M/MW TIC)
- Operational cost (OPEX) of electrolysers
- Forecast future cost reduction in CAPEX due to scale-up

Each criterion is discussed in detail below and forms the basis for the conclusions presented in this analysis.

Table *19* sets out the PEM vs alkaline solar and electrolysis capacities required to meet DNM's needs in accordance with the above criteria.

	PEM	Alkaline
Solar Installed (MW)	200	
Electrolysis (MW)	160	180

Table 19: RHF Main Component Sizing

The following sets out how these capacities were derived and the basis for the proposed technology recommendation.

7.2.1 Degradation Analysis

The first step in the analysis was to examine the effects of electrolyser degradation to ensure that a hydrogen supply of 23.8tpd to DNM can be achieved for the full 25-year operating lifecycle of the facility. Consumption rates for electrolysers at a range of operating capacities as provided by suppliers were utilized for 25-year electrolyser performance models. This degradation analysis was undertaken utilising the specifications provided by leading OEMs for PEM and alkaline electrolysers and included the following assumptions in Table *20*.

Assumption	PEM	Alkaline
Start-up/Min Power Capacity	5%	20%
Maximum Operational Capacity	120%	110%
Stack Degradation	0.4% Every year	Zero loss first year, 1% every following year
Hydrogen Drying Loss	3%	
DC/DC Converter loss	2%	
Electrolyser Base Size	2 x 2.5MW Modules	
Power Supply	Constant for hour intervals	
Electrolyser Efficiency – Start Up	40.1 kW/kg of H_2	42.3 kW/kg of H_2
Electrolyser Efficiency - Nominal	48.4 kW/kg of H_2	49 kW/kg of H_2
Electrolyser Efficiency - Maximum	50.2 kW/kg of H_2	49.8 kW/kg of H_2

Table 20: PEM vs Alkaline Modelling Assumptions

Further Assumptions:

- Operation of the electrolysers will be directly correlated to solar power supply (no ramp losses)
- Direct power to stack to be analysed, no BOP or BOS considered. This study aims to compare both technologies without any bias on the total amount of additional auxiliary power required to run the electrolysers. The difference in auxiliary systems is discussed in further detail in section 7.2.3, system costing
- Power consumption rates (stack efficiency) received from Hydrogenics to be used for PEM and published nel stack efficiencies[27] utilised for alkaline
- Stack efficiencies have been converted from kWh/Nm^3 to kWh/kg using a factor of 11.13

The PEM specification states that electrolyser stacks degrade at a rate of less than 1% per annum, assuming the electrolyser operates 24-hours a day, 365 days a year (8,760 hours per year) at its rated capacity. Due to the nature of solar power supply variance, PEM electrolyser utilisation is 50% (approximately 4,339 hours) in Moranbah with a CF of 38%.

OEM advice is that the number of cycles does not have a substantial impact on electrolyser degradation for PEM electrolysers (such as that encountered in batteries). The efficiency loss was calculated to be 0.4% each year, calculated by multiplying the design degradation

[27] nel - A-series Alkaline Electrolyser: https://nelhydrogen.com/product/atmospheric-alkaline-electrolyser-a-series/

rate by the CF of the electrolyser. CF was calculated based on modelled H_2 production after drying losses (9.6ktpa).

For the alkaline stack it is estimated that there is no loss due to degradation in the first year of operation and a loss of 1% efficiency every year after that. Due to the requirement to either 'keep warm' or fully purge and cold restart alkaline electrolysers when power supply drops below 20%, the degradation rate is not expected drop below 1% for intermittent utilisation. This is a key difference between PEM and alkaline technology.

The degradation of alkaline electrolysers is approximately 1% per year when operated between 20-110% in a continuous manner. When operating for periods of time below 30% of the electrolyser's capacity, the rate of degradation of the alkaline stack is likely to be higher than the average figure. Operating below 30% leads to stray currents which cause impurities e.g. oxygen in the hydrogen stream. These impurities degrade the electrolyser membranes, increasing the degradation rate of the cell stack. In cases where the power supply is variable – i.e. the electrolyser regularly ramps up and down below 30% capacity – the likelihood of a degradation rate of 1% per year or higher is expected and therefore was factored into the model.

When determining the hydrogen production pattern for the alkaline electrolyser, it was assumed that alkaline electrolysers have minimum turndown of 20% compared to the PEM system of 5%. In general, alkaline systems operate above 20% capacity to prevent the formation of impurities within the hydrogen, e.g. high concentrations of oxygen. Therefore, for this study, the alkaline electrolyser operating range was modelled between 20-110% of nominal capacity. High oxygen concentrations in the hydrogen stream are not desirable as they would trip safety valves in the system causing a complete shutdown and purge. Hydrogen production would cease, having detrimental effects on hydrogen supply.

PEM electrolysers can operate up to 120% of nominal capacity with no detrimental effect to the electrolyser stack, with turndown to as low as 1%. Operation at very low rates is only required for short periods at dawn and dusk and may introduce control issues. Therefore, the PEM electrolyser operating range is assessed as between 5-120% of nominal capacity.

Figure 12 below outlines the effect of degradation on the electrolyser efficiency (power consumption per kg of H_2 produced) over 25 years for both the PEM and alkaline electrolysers. The PEM electrolyser has a lower energy demand over time compared to the alkaline electrolyser due to the higher degradation rate for the alkaline electrolyser.

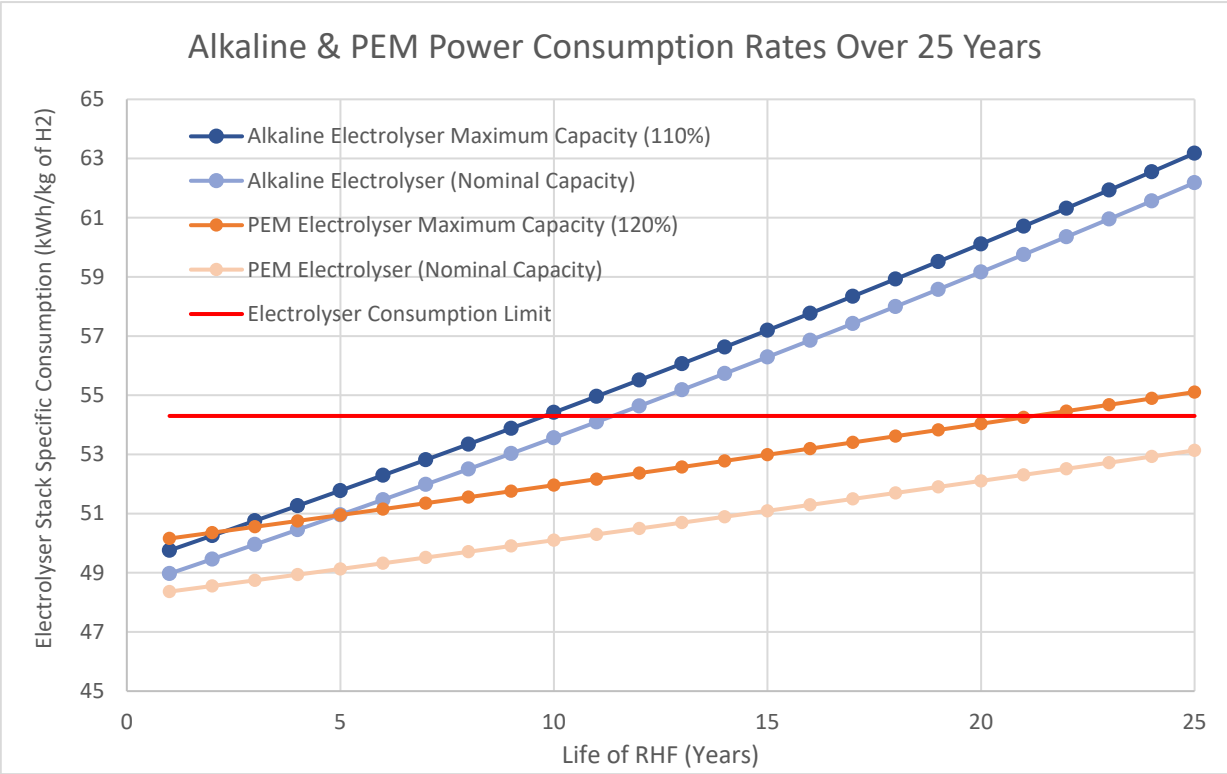


Figure 12: Electrolyser Stack Efficiency Analysis

Basic equipment design dictates that there is a limit to the power that can be injected into the electrolyser stack. As the stacks age and unit power consumption increases, eventually a component in the BOP (typically electrical supply or cooling) will reach its design limits, which in turn will then limit the hydrogen output from the stacks. This typically triggers stack refurbishment. After this consumption limit there would be a reduction in the hydrogen production as the electrolyser would no longer be able to run at the maximum current density. During the detailed engineering design phase, a review of the system would be undertaken to determine if a more cost-effective solution rather than simply adding in a new refurbished stack. This review would outline if it would make sense to add extra design margin in the sub-systems to keep the stacks running longer.

As demonstrated in Figure 12, the PEM electrolyser, for its maximum operating capacity, reaches the consumption limit in year 21 and the nominal capacity does not reach that same limit until after the 25-year design life. It is assumed for this study that no stack refurbishment is required for the PEM system as the minor mismatch between upper limit power after year 22 will be addressed in the next design phase.

However, the alkaline system reaches the limit for its maximum capacity in year 10. This indicates that the alkaline electrolyser will require a refurbishment approximately in year 11, thus adding a large cost to the operation of the RHF. Electrolyser costing will be examined in section 7.2.3 in further detail.

7.2.2 Electrolyser Utilisation and Efficiency

Figure 13 illustrates the total hydrogen produced by each of the alkaline and PEM electrolysers at their respective operating capacity ranges. The hydrogen produced, for both PEM and alkaline electrolysers, was calculated as a function of electrolyser efficiency and flow rate. The hydrogen was totalled across the range of operational capacities using the hydrogen produced from the function.

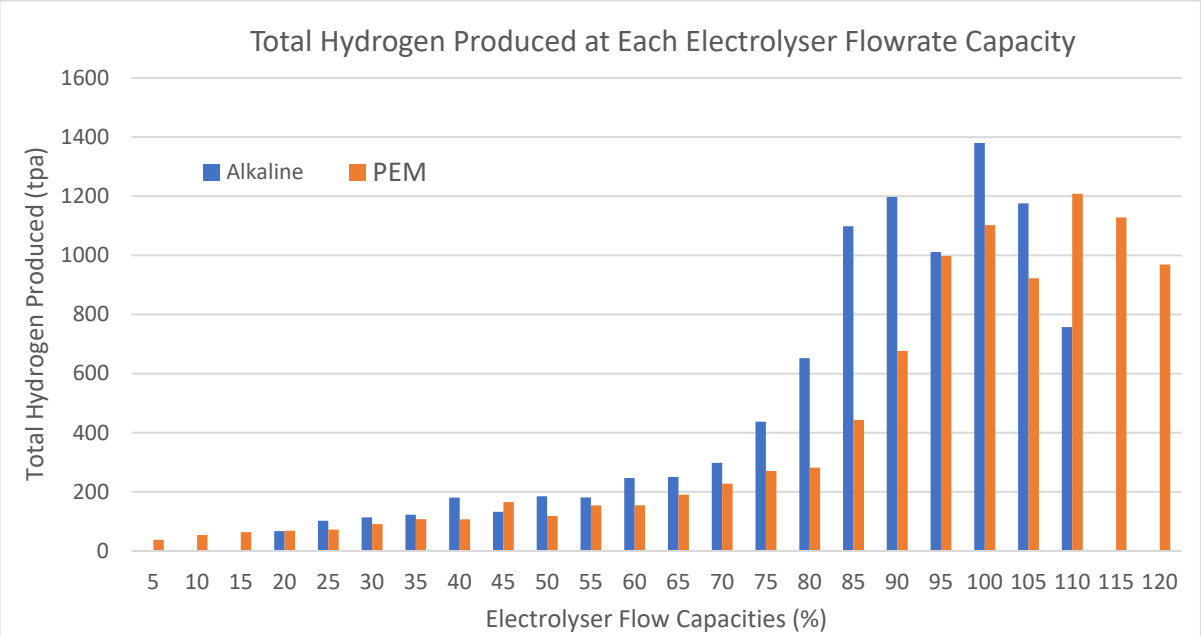


Figure 13: Total Hydrogen Produced at Each Electrolyser Capacity for Alkaline and PEM Electrolysers

Figure 14 classifies the total hours of operation for the PEM and alkaline electrolysers showing the variance in operational times in relation to the operating capacity ranges of both electrolysers. The wider operating range for the PEM electrolyser allows more operating hours at low capacity, as well as significant production from high-rate peak capacity. Based on the average solar profile in Moranbah, this results in overall higher utilisation and CF for a given nominal electrolysis capacity. Thus, to produce an equivalent amount of hydrogen, the alkaline electrolyser must operate at lower capacities for longer periods of time compared to the PEM electrolyser. Given time of operation is limited by the solar resource, more electrolysis capacity is required.

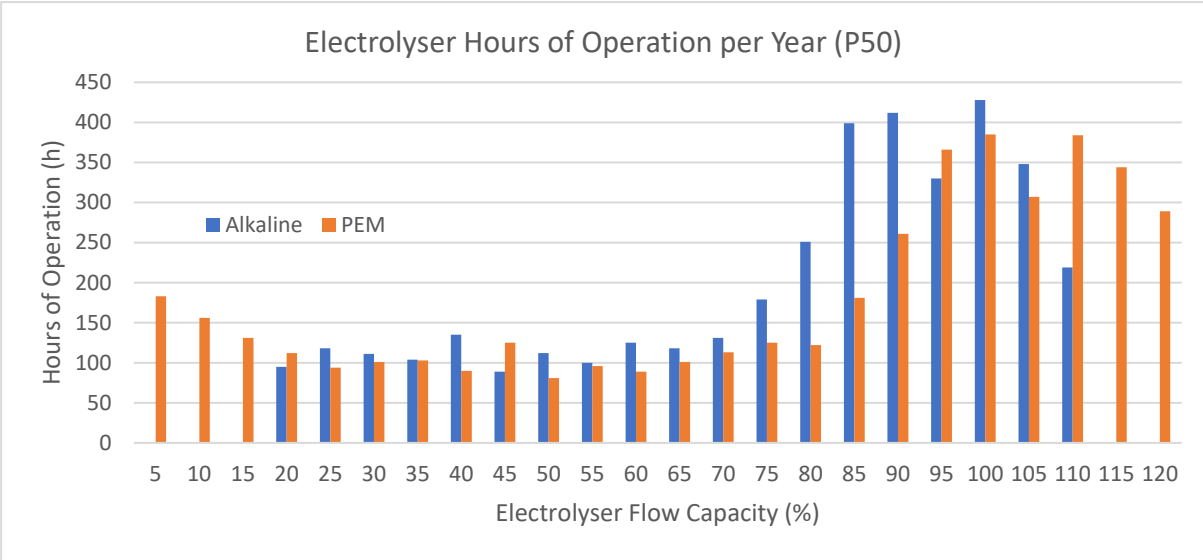


Figure 14: Electrolyser Hours of Operation

Table *21* summarises the total electrolyser utilisation and CF for PEM and alkaline electrolysers if all hydrogen could be captured or used. A larger operating range of the PEM electrolyser results in a 7% increase in utilisation. As a result of the higher utilisation, the PEM system requires less electrolyser capacity compared to the alkaline system.

The amount of hydrogen produced demonstrates how both the PEM and alkaline systems can service DNM's needs annually, given DNM's annual hydrogen requirement is 8,687tpa based on 23.8tpd.

	Electrolyser Capacity	Total Hydrogen Produced	Total Utilisation	CF	Nominal Electrolyser Capacity
	(MW)	(ktpa)	(%)	(%)	(t/h)
PEM	160	9.6	50	38	2.88
Alkaline	180	9.6	43	34	3.24

Table 21: Electrolyser Utilisation, CF and Hydrogen Production

As this comparison is comparing the power required at the stack, not considering the BOS requirements, the stack power is lower than that of the nameplate value of the installed capacity. Allowing 20MW of BOS power for both systems provides the overall nominal stack power consumption of 140MW and 160MW, for PEM and alkaline electrolysers respectively.

Seasonal variation results in more hydrogen generation in summer than winter due to higher solar irradiance in summer. Notwithstanding any changes in DNM's demand across a year, seasonal variation would result in a shortfall between demand and supply in winter and a surplus in summer. Hydrogen storage can partly compensate for this variation, increasing the proportion of daily hydrogen demand throughout the year. This analysis is outlined in section 9.

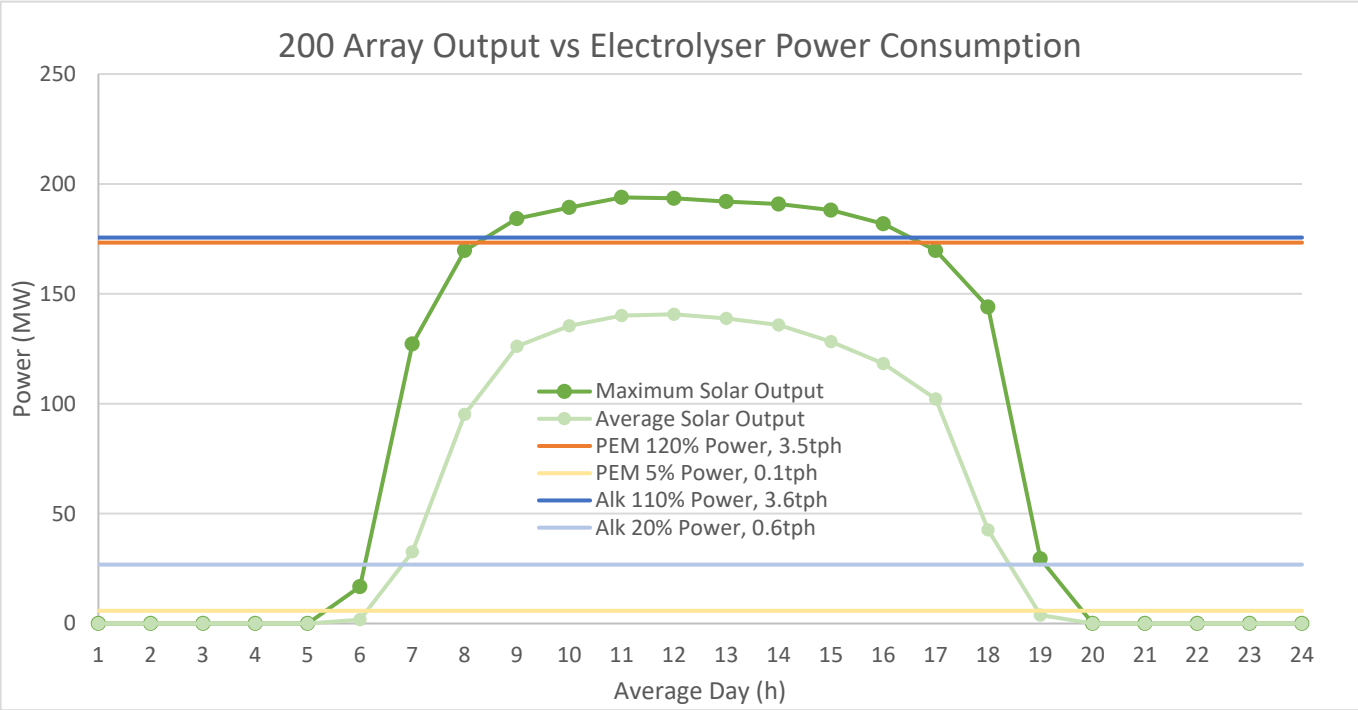


Figure 15: Comparison of Electrolyser Operating Power Ranges and Solar Array Output

Figure 15 outlines the operating ranges of both the PEM and Alkaline electrolysers sized to deliver the DNM demand for 8,687tpa of H_2 (Note: flowrates denoted are before drying losses). The gap between the solar power available and the maximum/minimum power required by the electrolysers at the stack demonstrates that there is surplus power available during peak irradiance when the solar farm is operating at its maximum. This power could be used to charge batteries, supply other power users, or simply not generated if not required. Sizing the electrolyser to utilise all the available solar energy would result in a lower utilisation of the electrolyser and higher overall capital costs.

Table *22* demonstrates the excess power produced by the solar array due to the operating conditions of both the PEM and alkaline electrolysers. The alkaline system's operating window of between 20% and 110% of nominal capacity restricts the amount of solar power it can utilise resulting in a higher power loss, in terms of un-used solar energy, compared to the PEM electrolyser.

	PEM	**Alkaline**
Solar power available (MWh/year)	466,000	
Solar Power not Utilised (MWh/year)	1,185	8,892
Percentage of Total (%)	0.3	1.9

Table 22: Solar Power Not Utilised Due to Electrolyser Operating Capacity

7.2.3 System Costing – PEM vs Alkaline

Installed cost for the major system components, electrolyser facility buildings and BOP is presented in Table *23*. The alkaline cost is based on a budget estimate from ThyssenKrupp provided to Incitec Pivot (IPL) and scaled and factored for installation. PEM electrolyser costing is based on direct quotation from Hydrogenics for the DNM electrolyser system and ANT estimates for locally supplied BOP. Future PEM installed costs are outlined in section 17 and future alkaline installed costs were determined utilising similar learning rates.

	Installed Cost (AU$M/MW) (2020 pricing)	Estimated 2022 Installed Cost (AU$M/MW)
PEM	1,336,883	1,251,925
Alkaline	1,311,475	1,049,180*

Table 23: Cost of Major Equipment (*assumes 20% reduction in cost of large scale alkaline)

Utilising the above costing for components, Table *24* was constructed to outline the total CAPEX and OPEX of major system equipment and facilities required for both the PEM and alkaline systems. It is assumed that the cost for all other facility components will be similar for both PEM and alkaline systems.

OPEX for the PEM and alkaline systems are estimated to be 1.5% of the CAPEX for every year of operation.

Due to the high degradation rate of the alkaline electrolyser there will be a requirement to replace the stacks. Assuming the stacks will need to be replaced once over the 25-year life of the RHF there will be an additional cost and resulting RHF downtime due to stack changeout times. Replacement cost is estimated using a nominal 25% of new CAPEX cost and a 30% reduction in real stack costs.

Given the overall cost scale and allowing for margins of error, the PEM system lifecycle cost is lower than the alkaline system by AU$71M, or almost 20%.

	PEM	Alkaline
Electrolyser Capacity (MW)	160	180
Electrolyser Cost (AU$M)	214	236
Estimated OPEX over 25 years (AU$M)	80	88
Stack overhauls (AU$M)	0	41
Total Cost (AU$M)	**294**	**365**

Table 24: Total Cost of Major RHF Equipment Comparison

Additional Considerations:

Besides upfront capital, there are further considerations that must be considered when considering the choice of electrolysers.

Large scale alkaline electrolysers typically produce hydrogen at atmospheric pressure compared to PEM electrolysers of 30-40bar. Consequently, there will be a requirement for additional hydrogen compression for the alkaline system. Alkaline systems are also substantially larger in physical footprint, requiring more building area.

The electrolyser plant will utilise solar power, so the plant will require a daily shutdown and standby operation at night. The PEM electrolyser system can maintain internal pressures within operating requirements during shutdown/standby operation. The alkaline electrolyser system, however, will require a complete nitrogen purge to stop cross contamination of oxygen and hydrogen during shutdown / standby procedures due to its near-atmospheric operating pressure as it can only turn down to 80-90% without any effect on the life of the stack[28]. Adding a shutdown procedure will amount to either an additional CAPEX cost for a nitrogen facility (which also requires more power) or an ongoing daily OPEX for utilisation of purchased nitrogen.

Alkaline electrolysers use 30% potassium hydroxide solution as an electrolyte while PEM does not use additional electrolytes. Using potassium hydroxide has inherent chemical handling hazards, increasing operational and maintenance costs compared to water.

7.3 Electrolyser Selection

Comparison between PEM and Alkaline electrolysis technology for this application determined that the PEM system has a significantly lower lifecycle cost than the alkaline system due to:

- The PEM electrolyser operating range is wider resulting in higher utilisation and CF from available solar power
- Alkaline electrolyser stacks will require a complete replacement at least once over the 25-year life of the RHF resulting in additional cost and downtime
- The alkaline electrolyser has a lower hydrogen output pressure increasing the cost for hydrogen compression
- The alkaline system will require additional land for the electrolyser building due to increase in electrolyser footprint
- The alkaline system will require much larger quantities of nitrogen for shutdown/standby operation overnight resulting in either a larger OPEX
- The alkaline system will require specialised hazard management facilities and protocols increasing the OPEX

Recommendation

The study selected PEM for the RHF as the PEM system had the lowest lifecycle cost, approximately 20% lower than an equivalent alkaline system in this application.

All subsequent modelling will be based on the PEM electrolysis technology.

[28] Proton: PEM vs Alkaline an electrolysis comparison
https://www.protononsite.com/about/resources/download/313

7.4 Electrolyser Manufacturers

The main manufacturers of PEM and/or alkaline electrolyser systems of similar scale to that required for the project are described briefly below. The top two in terms of volumes produced are Hydrogenics and nel Proton with collectively hundreds of electrolysers operating globally. ThyssenKrupp, ITM and Siemens have entered the market more recently and have between 1 to 6 electrolysers operating globally. Manufacturers listed below are not a complete list of all electrolyser companies in the market. It is understood that there are several emerging Chinese manufacturers that have not been considered due to lack of market and installation information available at the time of writing. ANT believes that the below list represents companies that have the capability of manufacturing the required size of electrolyser proposed from this project.

PEM Electrolyser Suppliers:

- Hydrogenics
- Siemens
- ITM

Alkaline Electrolyser Suppliers:

- nel
- TKS
- McPhy
- Cockerill Jingli

Based on the recommendation to proceed with a PEM system, alkaline system suppliers have been omitted. Of PEM options, Hydrogenics is one of the few suppliers with multiple electrolyser sites operating globally and in conjunction with Air Liquide, is currently building the world's largest PEM system (20MW) in Canada.

As of the end of 2019, Siemens had less than five[29] installed PEM systems globally and had only undertaken concept designs for systems greater than 1.25MW. ITM had installed less than 30[30] systems globally, all systems being less than 1.5MW and had no known large-scale systems designed or deployed.

Hydrogenics is developing the largest standalone single electrolyser stack (3MW) and currently has standalone electrolyser stacks of 2.5MW stacks operating in hydrogen production facilities globally. Consequently, Hydrogenics is recommended as the preferred PEM electrolyser supplier for the project.

[29] Siemens Energy: Our Systems in the Field: https://www.siemens-energy.com/global/en/offerings/renewable-energy/hydrogen-solutions.html

[30] Riding the Green hydrogen Wave: https://www.itm-power.com/images/Investors/PresentationsAndResearch/First-Berlin-ITM_LN-2019-02-20_EN.pdf, page 12

8. Impact of AC vs DC Electrolyser Connections

Electrolysis requires DC electricity to split water into H_2 and O_2. Traditional electrolysers draw AC grid power, which is converted to DC via transformers, splitters and rectifiers. Solar cells convert solar irradiation to DC power, which is traditionally then transmitted via a DC - AC transformer to the grid. ANT has identified and investigated the potential economic and engineering efficiencies that can be gained by using a direct DC/DC power solution from renewable generation to electrolysis.

Three potential benefits of a direct DC/DC connection for the RHF are:

- Greater proportion of renewable energy produced converted to hydrogen production
- Reduction in total cost of installed solar facility compared to an AC system
- Reduction in cost of power electronics for the electrolysers

When reviewing the losses for both the DC and AC connected system, it is important to note that the losses must be calculated annually because they will be different for every hour in the year. As a result, all losses are represented as a total energy loss for the first year of operation.

Figure 16 demonstrates the solar panel to stack losses comparing DC/AC/DC versus DC/DC. The DC/AC/DC option results in 19% power loss to the electrolyser stack. The DC/DC option results in 16.5% power loss to the electrolyser stack. A DC/DC option represents a 2.5% greater power utilisation. If a DC/AC/DC option is chosen, the solar facility will need a 2.5% increase in capacity to provide the same usable power, or approximately 5MW.

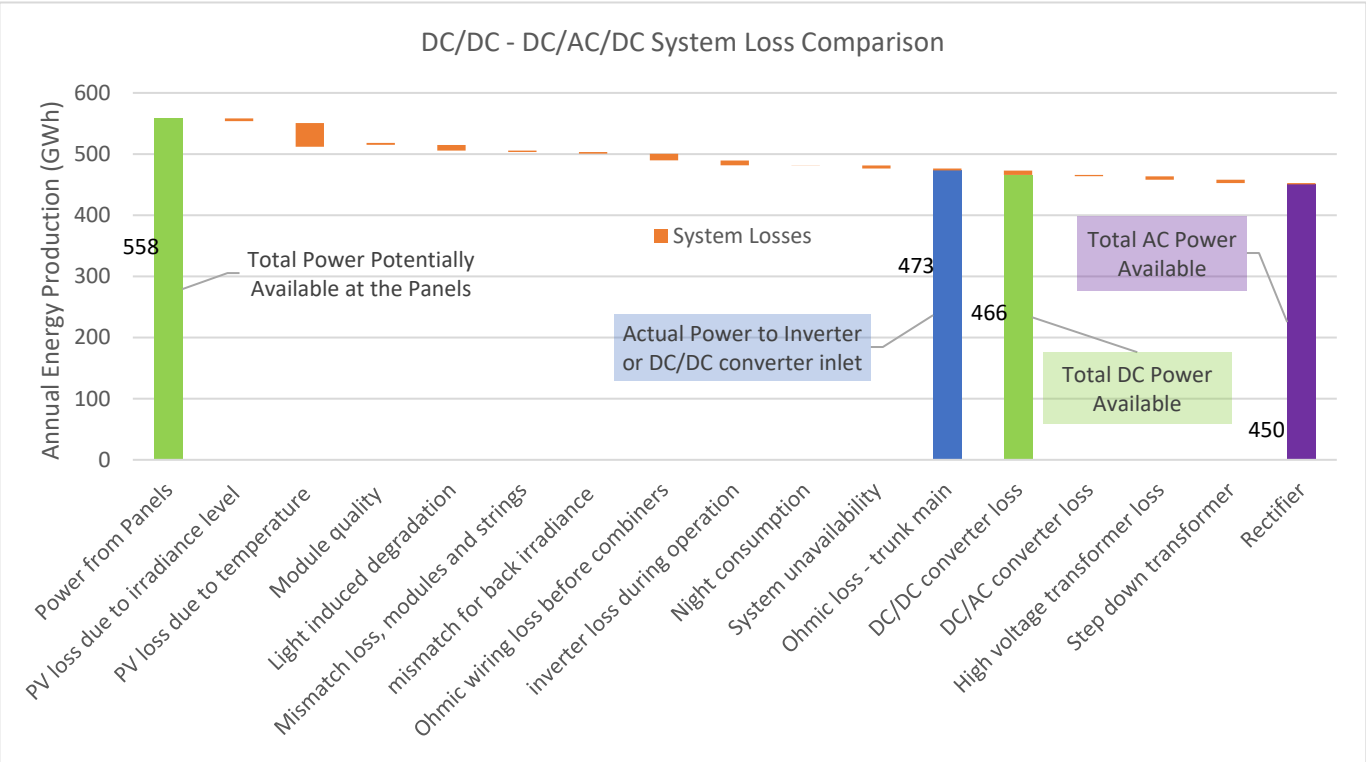


Figure 16: Total Annual System Losses – DC/AC-DC vs DC-DC

The estimated installed project cost for the DC solar farm is AU$1.00/MW, significantly lower than the $1.10[31] to $1.20 figure typically quoted. The major difference is the additional power conversion equipment required for the AC connected system. These numbers are used in Table *25* to determine the potential cost benefits of DC/DC versus DC/AC/DC.

The third factor driving DC/DC development is the additional power electronic cost associated with the inversion and transformation of AC/DC. Approximately one third of installed electrolyser costs arise from power electronics and controls. It is estimated the extra power electronic equipment for the DC/AC/DC system will be an additional 11% of the installed capital cost calculated for this project. This additional cost has been used in Table *25* below to summarise the economic benefits of a DC/DC versus a DC/AC/DC solution.

		DC/DC	DC/AC/DC	Savings
Max. solar energy required for 24tpd H_2 production	MW	202	207	-
Solar farm cost excluding power equipment	AU$M	202	207	-
Additional solar farm power equipment	AU$M	0	14	-
Solar farm total installed cost	AU$M	202	221	19
Electrolyser power equipment cost	AU$M	13	18	5
Estimated capital cost saving using DC/DC solution	**AU$M**	**-**	**-**	**24**

Table 25: Comparison Between DC/DC and AC/DC

[31] Kerang Solar Farm Fact Sheet: https://saaccionacomau.blob.core.windows.net/media/5346686/kerang-fact-sheet-dec-2017.pdf , page 1

9. Determination of Hydrogen Buffer Storage

The concept of the RHF project is the delivery of hydrogen to the DNM ammonium nitrate plant in a manner competitive with alternative supplies. A key element is reliable and consistent supply 24 hours per day, 365 days per year. To maintain a steady supply to DNM with an intermittent renewable energy source, a buffer storage is required. This storage can come in two forms: hydrogen tanks or batteries.

Batteries were found to be significantly more expensive compared to hydrogen buffer tanks based on the following assumptions and configuration:

- If fully utilised, 23.8tpd H_2 requirement means twelve 5MW electrolysis units are required (running at nominal flow of 90kg/h or 2.16tpd each) consuming 60MW of power
- Overnight (12 hours) power demand is supplied by batteries only
- Battery energy cannot be depleted below 20% of capacity to reduce degradation
- Hornsdale Power Reserve in South Australia battery install cost used for comparison price (AU$90M for 100MW, 129MWh)

Table 26 outlines the battery configuration and CAPEX cost required to run the electrolysers overnight with a battery system.

System Requirement	Unit
Electrolyser Power Draw - Nominal (MW)	60
Energy Required (MWh)	720
Battery Sizing (MWh, MW)	864, 60
Battery Cost (AU$M/MW)	0.9
Total Cost of Battery System (AU$M)	778

Table 26: Overnight Battery Requirements

It is observed that the cost of installing a battery system, at AU$778M is considerably higher than the entire RHF cost and compares poorly to hydrogen buffer storage which was estimated at AU$111M equating to approximately AU$2M per tonne installed. Even with the significant reduction in the sizing of the electrolysis facility (from 160MW to 60MW), batteries are almost three times more expensive than hydrogen storage and are not suitable as a power source for hydrogen production.

As the main power source for the RHF will be solar, without battery storage, hydrogen will only be produced during daylight hours. Storage capacity is essential to deliver DNM hydrogen overnight and also to meet demands in periods of low hydrogen production due to inclement weather or seasonal variation.

Hydrogen storage is relatively expensive due to the low density of hydrogen gas and the necessary high storage pressures to store meaningful quantities. A trade-off is therefore required between the amount of storage provided and the amount of available hydrogen that is captured. This trade-off seeks to optimise the upfront cost of storage with the lifecycle benefit of additional hydrogen capture.

To determine the amount of hydrogen storage required, the following analysis steps were performed utilising the year one's hydrogen production.

1. Determine the amount of hydrogen that can be produced with no storage constraint across the year
2. Overlay the demand from DNM to simulate a hydrogen 'stock' level
3. Link supply and demand and set limits on the hydrogen stock level
4. Calculate the total H_2 produced and supplied to DNM
5. Repeat steps 3 and 4 for different hydrogen storage sizes
6. Test impact of flexing DNM offtake

This analysis provides data on the total hydrogen supplied to DNM using different hydrogen storage capacities, as well as the duration that target production is not met in the year. This data was then used to calculate the capital cost impact and hydrogen revenue benefit for various hydrogen storage sizes.

9.1. Hydrogen Production and DNM Offtake

Figure 17 was constructed to develop an understanding of hydrogen production across the year without any hydrogen demand/storage constraint. Production was calculated hourly using solar generation data averaged over 12 years.

Overlaying daily offtake of 23.8tpd by DNM, it can be observed that supply exceeds offtake in most months, but offtake exceeds supply for some period in winter and during the wet season (Dec – Mar).

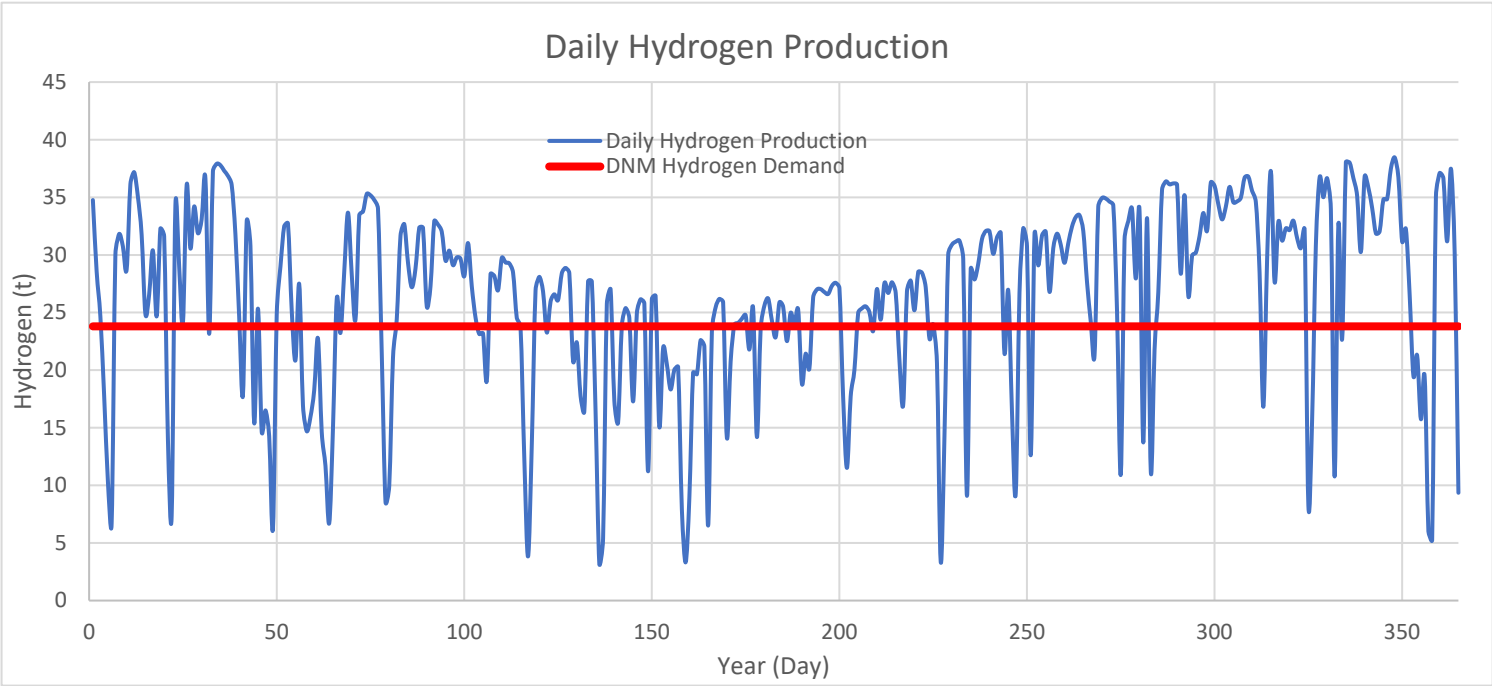


Figure 17: Comparison Between Daily DNM Offtake vs Hydrogen Production

9.2. Link Supply & Demand and Limit Storage

By limiting storage, days of over-production are constrained and supply is restricted if storage is emptied. Figure 18 presents the hydrogen storage level across the year for a storage that ensures the required DNM offtake is achieved every day of the year. A total of 224t of hydrogen storage would be required to offset the winter reduction in hydrogen production. As this represents an 'average' operating year, it is recognised that in below average years, even with this storage, supply may not be maintained.

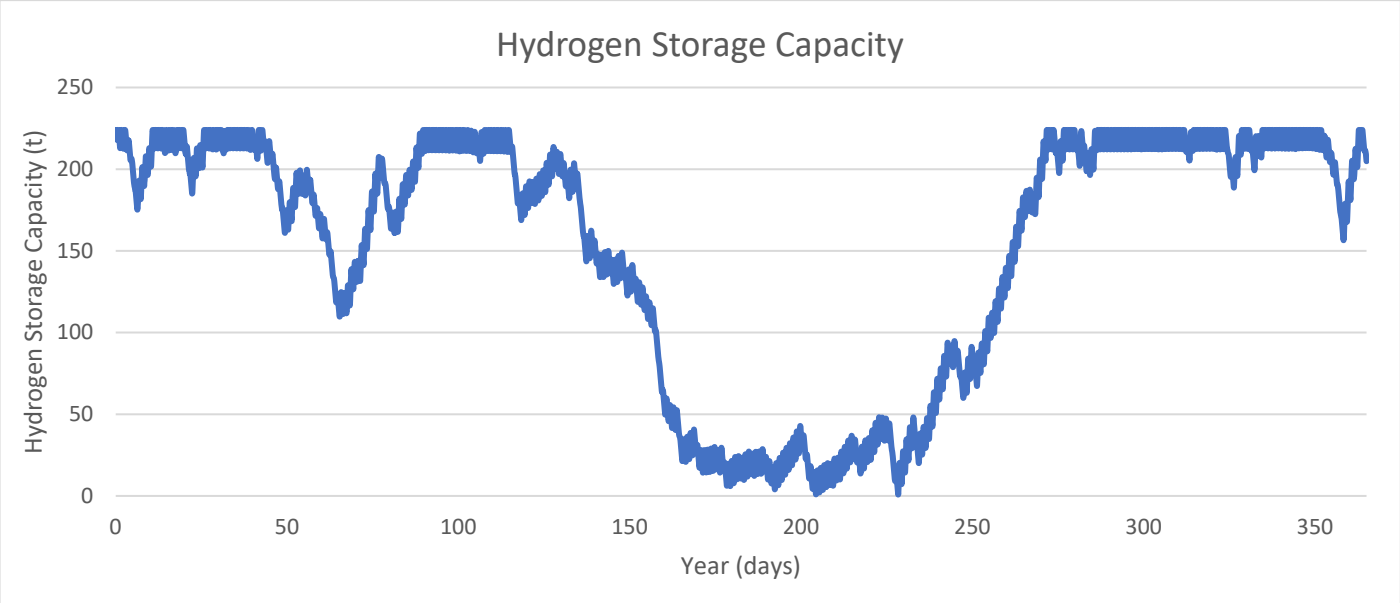


Figure 18: Hydrogen Storage Capacity

9.3. Calculate H_2 Supplied to DNM and Repeat for Various Storage Sizes

Recognising that 224t of storage is commercially unfeasible and the relatively short period of undersupply in winter and wet season, the simulation was repeated for various storage capacities to determine the impact on hydrogen supply. Figure 19 outlines the yearly hydrogen supply at varying hydrogen storage capacities. It can be observed that the DNM demand of 8,687tpa is only met at the storage capacity of 224t. The incremental hydrogen capture with additional storage is minimal, with 95% of the supplied volume being met with only 35t of storage.

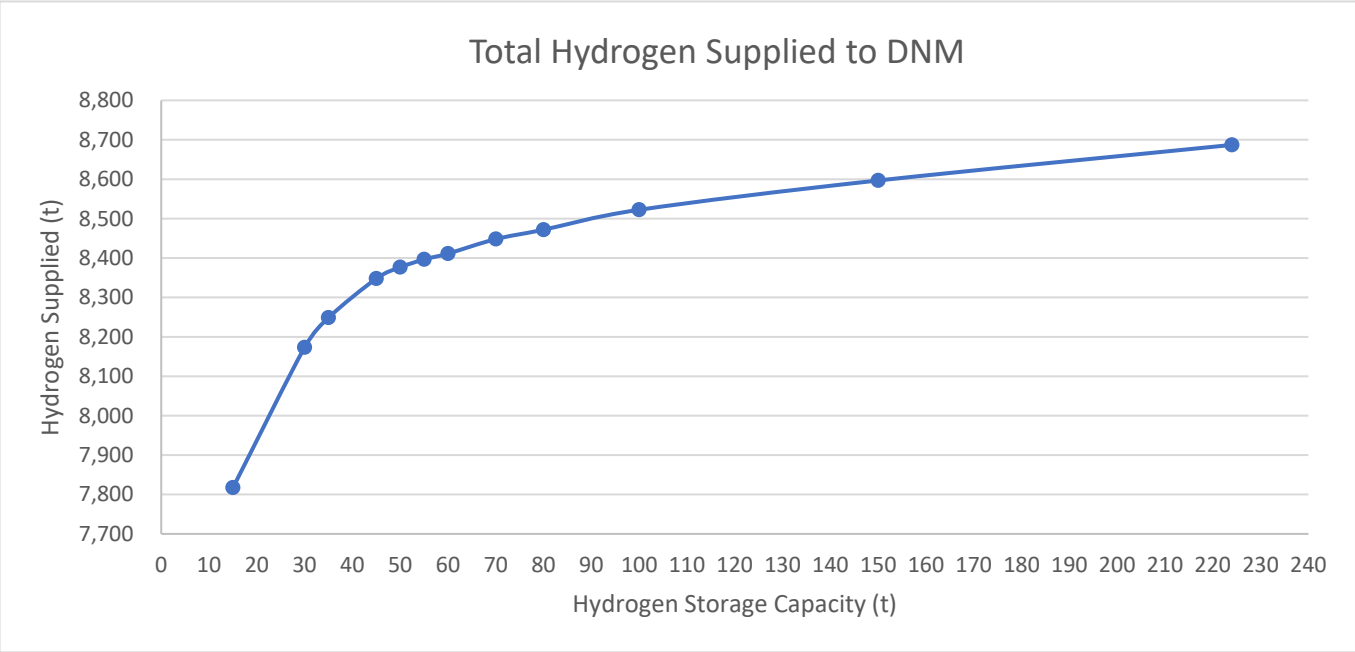


Figure 19: Total Hydrogen Supply Annually at Varying Hydrogen Storage Capacities

Figure 20 shows the total hours of no hydrogen supply to DNM for various storage capacities due to the storage limitation. As the DNM ammonia plant must have a continuous supply of hydrogen to run, it is not acceptable to have any time period of no hydrogen supply.

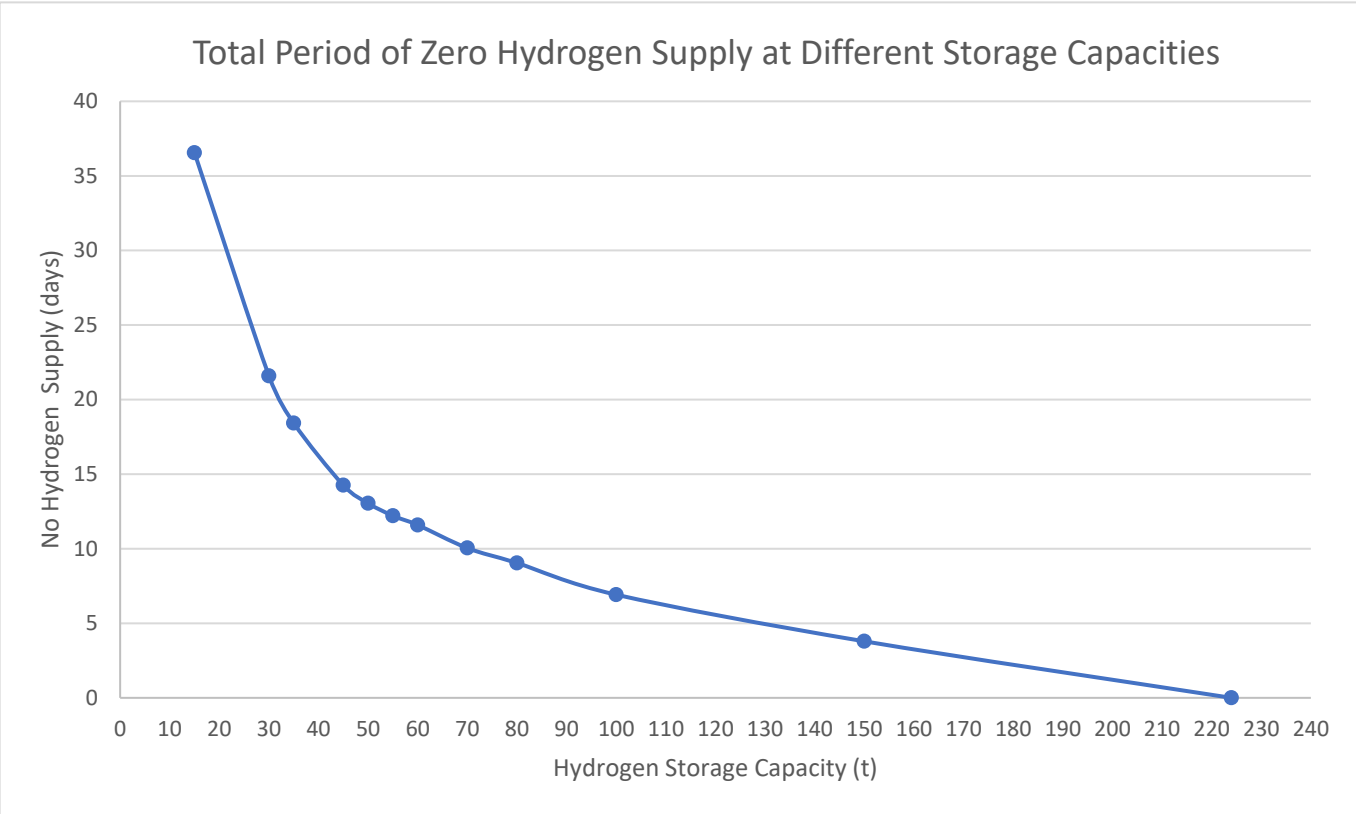


Figure 20: Total hours of no Hydrogen Supply at Varying Storage Capacities

Based on this analysis, the size of the hydrogen storage could be significantly reduced if DNM were willing to accept some periods with zero supply. Given ammonia plants do have turndown capability and the amount of lost production is relatively low, there is significant cost benefit to allowing periods of turndown operation below the nominal 23.8tpd hydrogen supply.

9.4. Evaluate Impact of Varying Supply to DNM

The study investigated a 23.8tpd hydrogen supply at a continuous rate of approximately one tonne (992kg) per hour to a continuous production ammonia plant, corresponding to a total of 8,687tpa. However, due to solar irradiance variation throughout the year, consideration of lowering the 23.8tpd offtake during low irradiance periods was made to maintain a competitive hydrogen cost. During winter and wet seasons, the electrolyser facility will experience a power deficit and will not be able to operate at maximum capacity due to the lack of solar irradiance. Hydrogen supply will be less than the 23.8tpd nominal demand and the hydrogen capacity within the tank storage will empty.

To prevent the hydrogen tanks from emptying, this study investigated the impact of allowing hydrogen supply to the ammonia facility to be reduced by up to 25% (18tpd or 750kg/h). At time periods where the hydrogen tank becomes empty (typically during winter and any inclement weather events), the supply to DNM is reduced from 23.8 to 18tpd for a specified number of hours before the tank is forecast to empty, increasing the hours of supply to DNM.

Conversely during summer, there is an abundance of solar power to the electrolyser facility creating a surplus of hydrogen. During summer hydrogen supply could be increased well beyond design flow. If there is flexibility in hydrogen supply to DNM (e.g. up to 120% of the nominal flow to 28.6tpd), this would increase the amount of hydrogen supplied by the RHF.

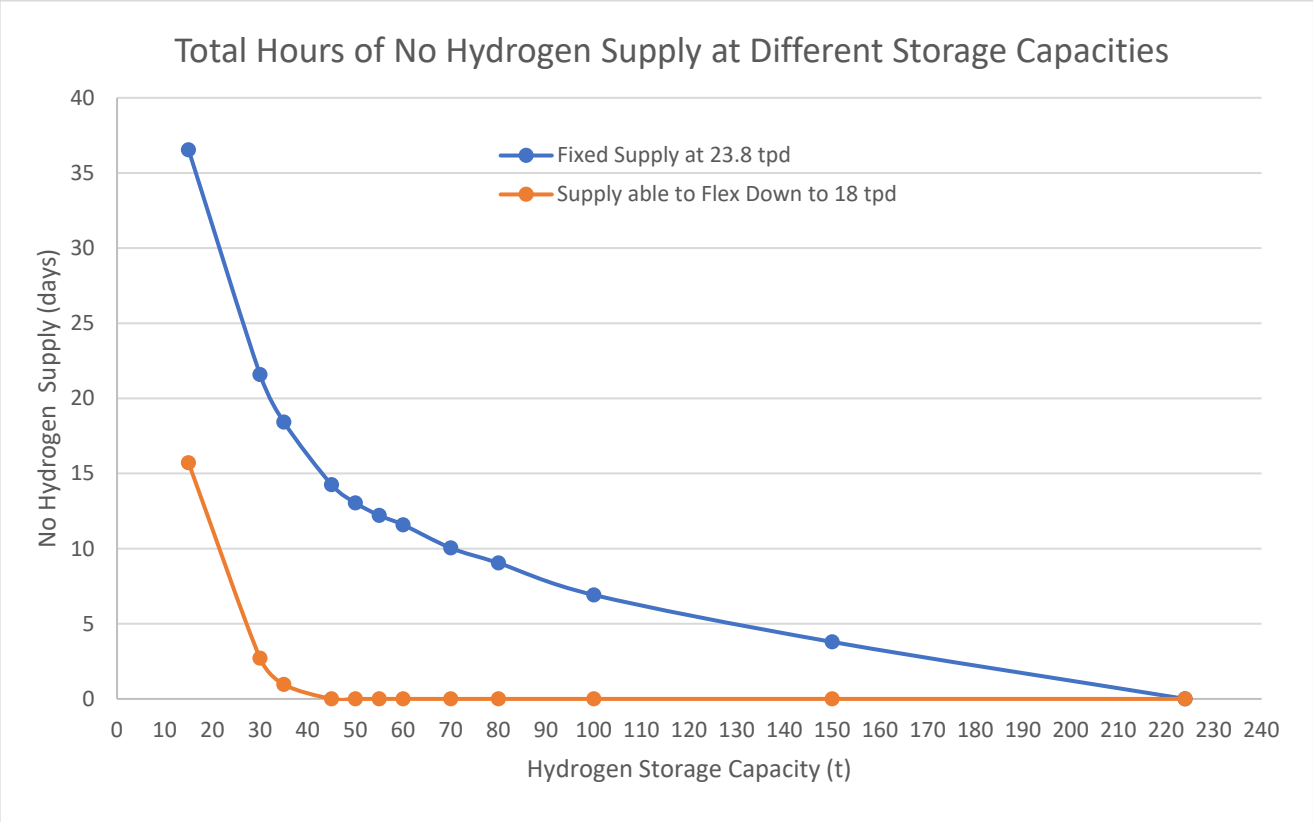


Figure 21: Hours of No Supply Comparison

Figure 21 shows the total days with no hydrogen supply at varying storage capacities for the two cases: constant 23.8tpd supply to DNM and a variable supply between 23.8 to 18tpd. The variable supply case ensures an acceptable hydrogen flow to DNM is maintained every hour.

Ramping down supply from 23 to 18tpd results in a net increase in annual total hydrogen supply to DNM. This arises because even though the flow decreases there is an increase in the total hours of supply. At an hourly interval less hydrogen is supplied however, over the course of the year the additional hours of supply more than compensate for the hourly difference.

Table 27 shows the operating case for the 45t storage capacity. By multiplying the hours of operation by the corresponding flow to DNM it can be observed that there is a slight increase in the total annual hydrogen supplied to DNM.

	No. of Hours at Zero Supply	Hours of Supply at 100% (992kg/h)	Hours of Supply at 75% (750 kg/h)	Total Hydrogen Supplied to DNM (tpa)
Constant Flow Case of 23.8tpd	342	8,418	0	8,348
Ramp Down Flow Case to 75% of 23.8tpd	0	7,607	1,153	8,408

Table 27: 45 t Storage Case

Figure 22 expands on Table *27* by showing the hydrogen supplied at a range of hydrogen storage capacities from 15 to 224t for the two supply cases. The figure shows that for a substantial number of storage capacities the variable supply case provides more net hydrogen supplied to DNM per annum.

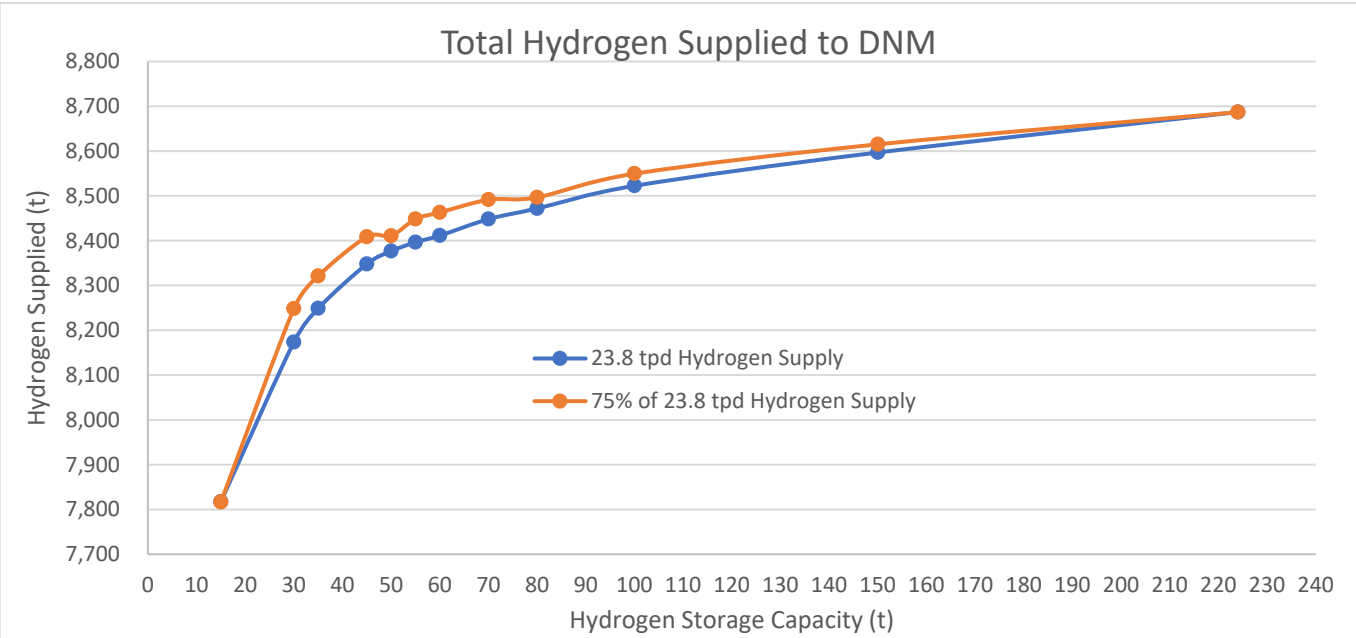


Figure 22: Total Hydrogen Supplied to DNM

Understanding that with turndown and limited storage the total hydrogen requirement for the year is still not being supplied to DNM, an allowance for the supply to flex upwards to 120% of the nominal alongside the 25% reduction was investigated. Figure 23 outlines the potential increase in hydrogen supplied to DNM if supply can flex upwards by 20%. Hydrogen supplied not only meets the 8,687tpa required by DNM but also produces a surplus amount of hydrogen (5-10%). No storage sizes below 45t were investigated as Figure 21 outlines that less than 45t will have periods of time where no hydrogen supplied is observed and would not meet the minimum design criteria.

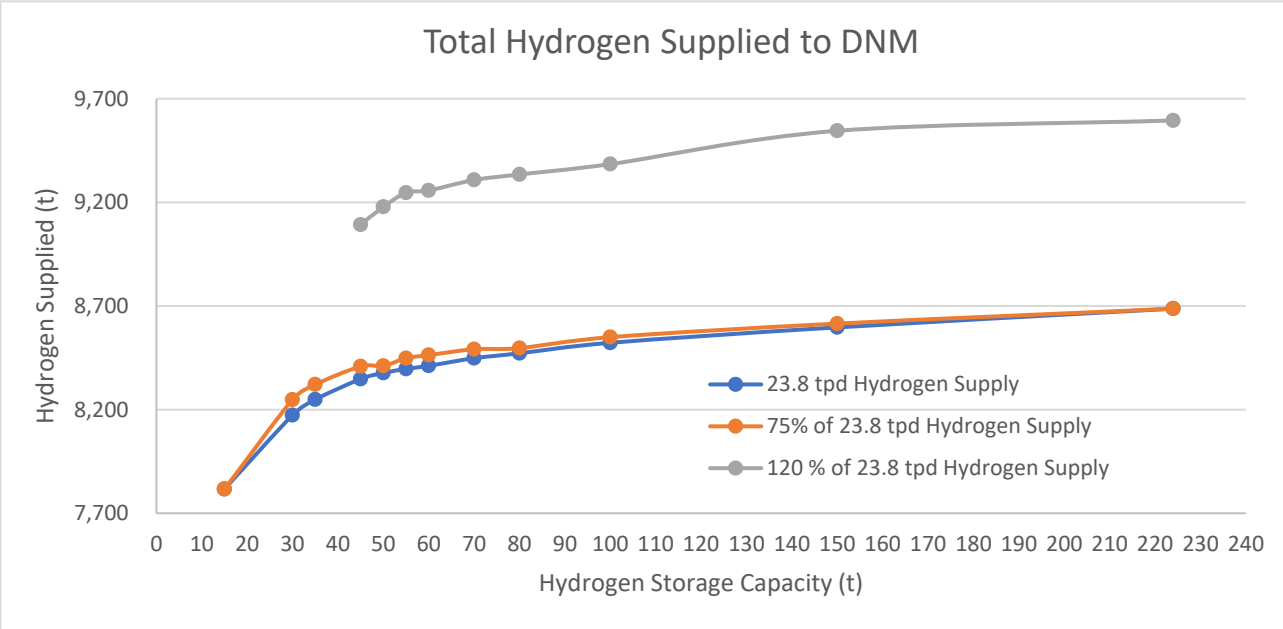


Figure 23: Total Hydrogen Supplied to DNM

9.5. Storage Recommendation

Using $2/kg as the hydrogen price, the NPV over 25 years of hydrogen production was calculated for varying storage capacities from the respective hydrogen supplies observed in Figure 23. The NPV for each storage capacity was calculated assuming:

- The first year's hydrogen production pattern for 25 years
- H_2 sale price indexation of 0.5% pa
- Discount rate of 4%
- Storage cost of $0.98M/t for 250 bar and $3.6M/t for 100bar tanks

Figure 24 outlines the present value of revenue from sold hydrogen minus the cost of storage at each storage capacity. It can be observed that there is insignificant revenue increase from allowing the supply to flex downwards by 25%. However, the potential revenue increase is substantial if the ammonia plant is over sized to allow for the 20% increase. This increase in revenue may lend itself to improving a business case for increasing the size of the ammonia plant to accept the increase in supply. The chart indicates that there is no present value benefit in increasing storage capacity, so sizing is determined by the smallest storage that allows uninterrupted operation of the ammonia plant.

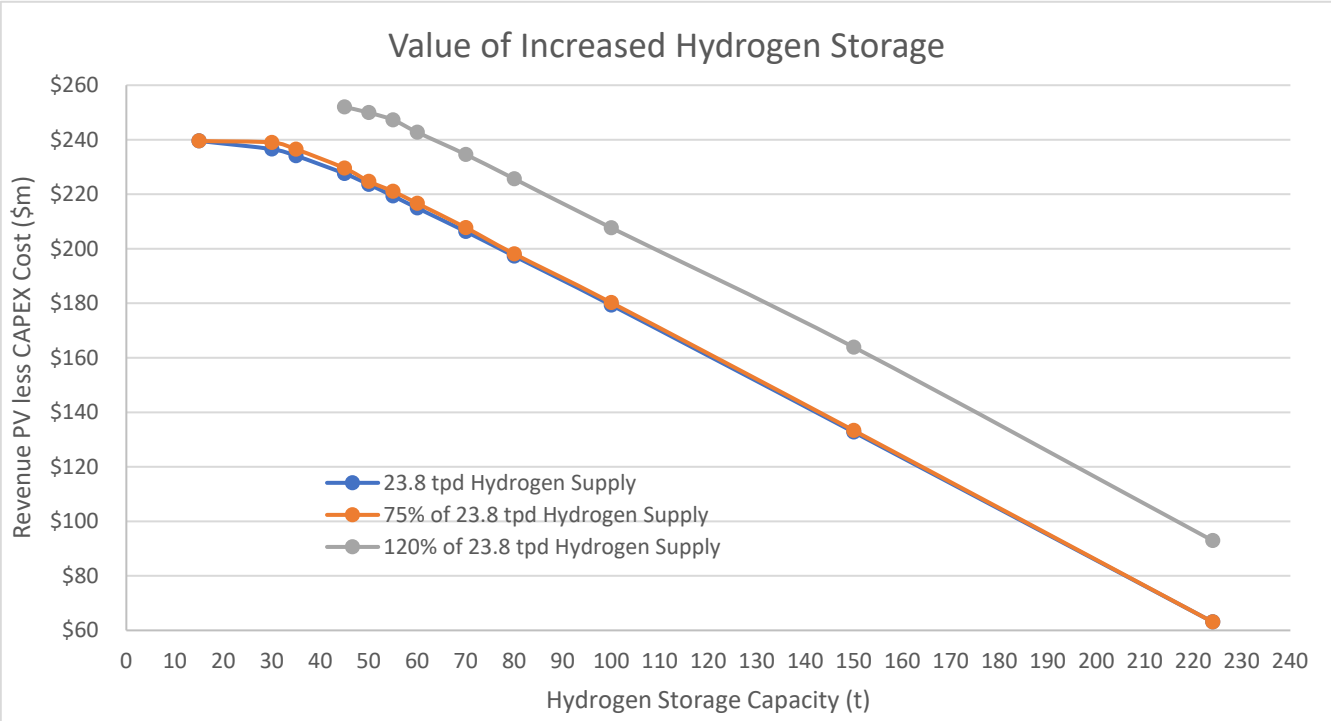


Figure 24: NPV of Sold Hydrogen Over 25 Years vs Cost of Storage

This analysis therefore suggests 45t as the optimal hydrogen storage. This is the lowest storage size where zero hours of no hydrogen supply is observed from the 25% reduction case. This sizing provides 8,348t of hydrogen supply in an average year which is 96% of the nominal RHF capacity at the design case of 23.8tpd (8,768tpa). With supply allowed to reduce by 25% this sizing provides 8,408t of hydrogen supply in an average year, which is 96.8% of the nominal RHF capacity.

Finally, if the supply can flex upwards by 20% of the nominal, this sizing provides 9,092t of hydrogen, which is 104% of the nominal RHF capacity, and provides a $24M increase in present value from the base case. If the ammonia plant was sized at 120% (28.6tpd of hydrogen) instead of the current facility sizing of 23.8tpd, then the ammonia plant would need to ramp down by 37% to prevent any supply disruption. This turn down factor is within the turn down capability of modern ammonia plants of 40%.

It was recognised that the solar data utilised to produce the hydrogen production pattern was for an "average" year. To accommodate for times of low irradiance, demonstrated by the solar data from 2010, additional storage would be justified. For the purposes of this feasibility study, a conservative storage size of 54t was utilised to allow for the yearly variance in solar irradiance.

9.6. Hydrogen Storage Alternatives

It was considered that hydrogen could be stored within the transport pipe network as an alternative to modular high-pressure storage units. However, due to the large quantity of required hydrogen storage, a very large pipeline would be required (~300km of DN500 piping). GPA Engineering (who was contracted to analyse the storage and transportation for the RHF) determined that it is more cost effective to store hydrogen in modular pressure vessels than in a pipeline as outlined in Table *28*.

Note - All costing assumes above ground installation.

Hydrogen Storage Method	$/kg of Hydrogen Installed
Pressure Vessel	1,207
Pipeline	14,115

Table 28: Cost Comparison of Hydrogen Storage Methods

There are alternative hydrogen storage methods compared to the traditional methods utilised in this project, including underground storage and metal-hydride. Manufactured underground storage works by utilising a lined underground bored cavity to form a large storage volume without the need for expensive metal tanks. Metal-hydride containers utilises a metal composite to absorb hydrogen at much lower pressures. Initial discussions were held with developers of these technologies; however, it was determined that these technologies are not yet beyond TRL7, hence they were not considered for this project at this stage.

10. Manufacturers of Key Process Equipment

The following list of potential major equipment suppliers per equipment type was evaluated during this feasibility study:

KEY PROCESS EQUIPMENT SUPPLIERS					
SOLAR POWER PANELS	**ELECYTROLYSERS**	**COMPRESSORS**	**HYDROGEN STORAGE**	**DC/DC CONVERSION**	**BOP**
Canadian Solar	NEL Proton	Andreas Hofer	Reuther	AMPT	Breezewater
Sunpower Corp	Hydrogenics Corp	Howden Thomassen	Hexagon Lincoln	SMA	Cooling Tower Sales
Suntech	ITM Power	PDC Machines	Rafael Calvera	Sungrow	Aggreko
Longi	Siemens		Wystrach	Strang	Alpha Laval

Table 29: Key Equipment Suppliers

11.1 Key Suppliers Identified and Prequalified

Based on their ability to meet the technical and commercial requirements of the study, the following list of major equipment suppliers per equipment type was chosen:

	CHOSEN PROCESS EQUIPMENT SUPPLIERS					
	SOLAR PANELS	**ELECYTROLYSERS**	**COMPRESSORS**	**HYDROGEN STORAGE**	**DC/DC CONVERSION**	**BOP**
Chosen Supplier	Sunpower Corporation	Hydrogenics	Howden Thomassen	EKC	SMA	Various
Country of Origin	China	Canada	Netherlands	Dubai	Germany	Australia
Local Content Portion	Mounting frames and tracking systems	System BOP	Interconnection	Interconnection	Interconnection	All BOP for hydrogen generation, transport & storage

Table 30: Process Equipment Suppliers

Local Content

To improve the RHF cost, local equipment and services content was a primary focus of this study. Although as outlined in Table *30*, no appropriate capital equipment for major plant items including solar panels, electrolysers, hydrogen compressors, hydrogen storage vessels and electrical DC/DC equipment was found to be available in Australia. Therefore, remaining equipment that could be supplied locally was constrained to BOP.

Table 32 outlines the local content achieved in the RHF design for 2020. Even though majority of equipment is sourced overseas, the local content required represents 35% of the total facility installed cost. In addition, approximately 88% of the operational cost is local content at an approximate value of $305M over the 25-year life of the project.

Components	Percentage of Component Cost (%)	Local Content per Component Cost (AUD$M)
Solar	23	55
H_2 Production	27	52
Cooling system	49	11
Auxiliary Power	51	16
Storage & Transport	52	58
Common Auxiliaries	25	5
EPC	100	25
Total Install	**35**	**222**

Table 31: Amount of local content involved in the cost of constructing and commissioning the RHF

11. Power Generation, Transformation and Degradation Analysis

An underlying principle of the RHF analysis is to understand and improve power efficiency including generation, transformation and use of power. Each of these are discussed below.

12.1 Power Generation

There are two major forms of power utilisation within the RHF, direct power to the electrolyser stacks and auxiliary systems (BOS, BOP, compression, security, lighting, control systems, etc.). Table *33* outlines the solar array size and available power recommended for the project.

	Solar Array Size	Max Power Observed (After Losses)
Electrolyser Stack Power (MW)	202	193
Auxiliary System (MW)	38	31

Table 32: Power Generation and Use System Sizing

The following sets out how these systems were derived and the basis for the solar sizing recommendation.

12.1.1 Solar Array – Electrolyser Stack Direct Power

Electrolysers use DC power for water electrolysis i.e. to split water and produce hydrogen. In the RHF the electrolysers will utilise direct DC power from a solar array without conversion to AC to improve power efficiency.

Traditionally electrolysers draw power from:

- AC grid connection with the power converted from AC to DC
- Solar arrays with the power converted from DC to AC and then back to DC to step the high voltage and low current power from the solar panel to low voltage and high current required for the electrolyser

Using a DC/DC connection bypasses the need for DC/AC converters for the main bulk of the required power at the electrolyser stacks, reducing power consumption and capital costs. This improves the production performance of the RHF and section 7 outlines the relationship between hydrogen production, the relevant power required and the efficiencies at all relevant electrolyser operating capacity steps incorporates the power transfer efficiency gained from a DC/DC connection.

ANT has worked with a number of suppliers, including SMA[32], a global leader in power conversion, to develop a DC/DC system that employs direct DC coupling to eliminate the need to convert DC power from the solar panel to AC and back to DC for the electrolyser.

Alternative DC/DC options including AMPT, Sungrow and Spang Power Electronics were also investigated and could be utilised in the final design.

12.1.2 Solar Array & Electrolyser Sizing

The electrolyser size was initially estimated using the average solar CF of 28%, which equates to an average operational time of 6.7 hours a day at the nominal rating of the electrolyser (45 kg/h for nameplate rating of 2.5MW). Based on the solar array producing the average power for 6.7 hours every day, each stack would produce 300kg of H_2, requiring 79 stacks or 197MW of electrolysis to produce 23.8tpd of H_2. Note: DC solar sizing only considers the power required at the stack which excludes the BOS and BOP. This reduces the required stack nominal power to approximately 175MW.

As the solar resource has significant overproduction (maximum output is almost 40% higher than average) and the electrolyser can be operated at up to 120% of it is nominal rated capacity, providing time periods where the electrolyser would be producing more hydrogen compared to the nominal, it was identified that the electrolyser size could be reduced to 160MW (with stack nominal power of 140MW), to lower the overall cost of the facility. Figure 25 outlines the total power demand of the electrolyser stacks at the range of operating capacities.

To size the solar array, the power produced on average needs to match the power consumed to produce the 23.8tpd of hydrogen required. This means the nominal demand of the stack (140MW) had to equate or be close to the average daily output of the solar resource. At the same time, it is understood that due to inclement weather events and the amount of irradiance available due to seasonality, there will be times of more or less hydrogen production compared to the nominal. Figure 26 shows the average daily output from the 202MW solar array, comparing the maximum, nominal and minimum power requirement from the electrolyser. This demonstrates how the 202MW solar array meets the desired criteria of producing an average of 140MW for most hours of the day.

These capacity sizes represent the minimal requirement to produce the required hydrogen over the course of a year. However, due to the variable nature of the power resource, hydrogen storage had to be added to the RHF to accommodate, as outlined in section 9.

[32] SMA: https://www.sma-australia.com.au/

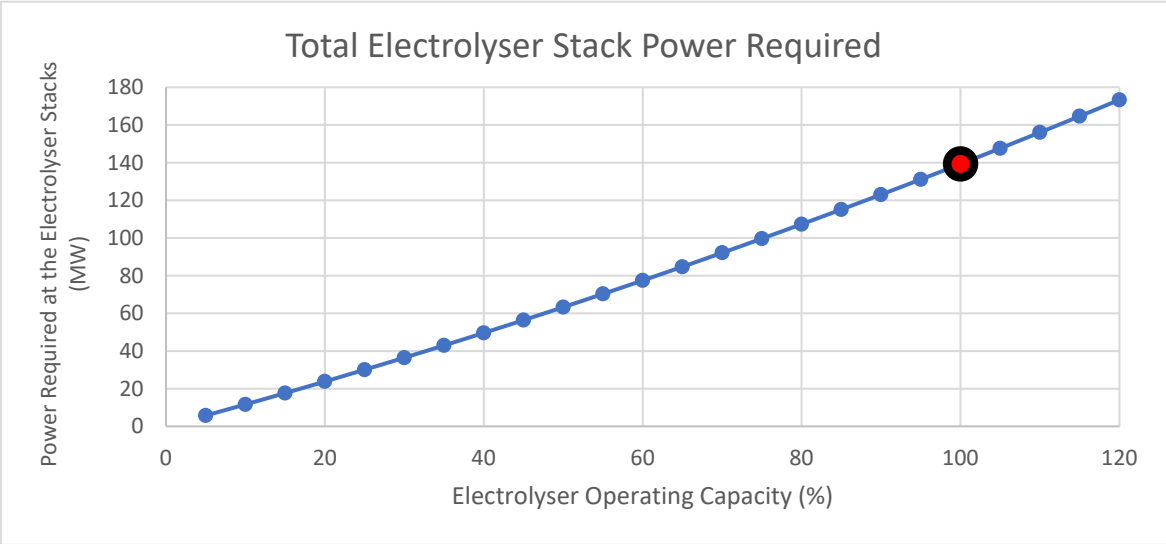


Figure 25: Total Power Electrolyser Power Requirement

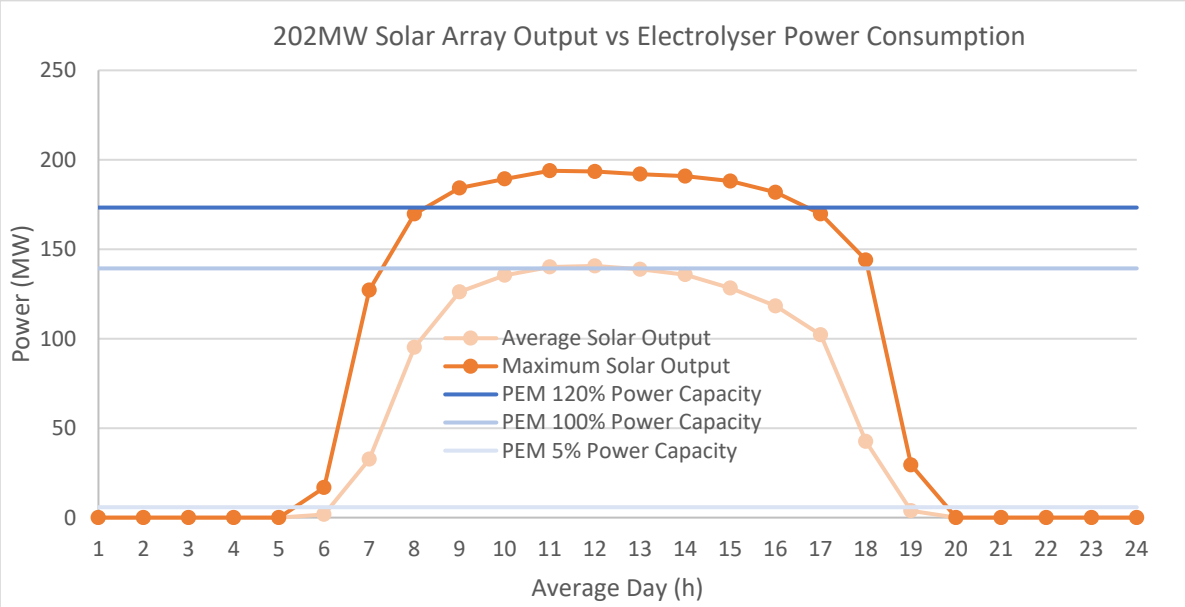


Figure 26: Daily Average Solar Array Output

12.1.3 Solar Array – AC Auxiliary Systems

Below is a summary of the auxiliary loads required for the RHF:

	Power Requirement (MW)
Electrolyser BOS, BOP and HVAC	9.5
Hydrogen Compression	5.4
Site General	3.3
Total	**18.2**
Total Power Requirement with Losses	***24.3***

Table 33: AC Load Requirements

Note: Losses used in calculation of total power required are maximum instantaneous loss assumptions.

Conservatively, to ensure there is sufficient power to service the potential load of 24MW, the solar array capacity for the AC auxiliary system will be oversized to deliver 30MW of power. As a result, of the 240MW installed power at the RHF, 38MW will be dedicated to running the AC system to account for the AC system losses (refer to section 8). At this stage, the AC system has been designed for the maximum power load case. However, actual operating conditions will be largely proportional to the rate of hydrogen production which consequently is related to the available power from the solar array.

These loads include all BOP and BOS required to run the RHF. It is assumed that direct power to the electrolysers at the stack level will be via DC/DC connection with all other equipment in the RHF serviced by a site-wide AC ring main with its own accompanying solar and back up battery system.

Alongside the 38MW of solar power there will be 10MWh, 20MW batteries connected to allow for start-up, shut-down, power smoothing due to inclement weather (cloud cover) and overnight auxiliary loads. Due to degradation, these batteries will need to be replaced every 10 years and this has been accounted for in the OPEX for the RHF.

Overnight Auxiliary Load

The hydrogen storage facility and the central office overnight load is minimal therefore, those facilities will be serviced by the AC auxiliary system. The overnight auxiliary power for the hydrogen trains however is substantial and as a result will be serviced by hydrogen fuel cells. Each fuel cell, with a total capacity of 120kW, will accommodate the overnight load for auxiliary systems such as lighting, security systems and standby operation of equipment. Hydrogen gas for the fuel cells will be supplied from the hydrogen transportation pipeline network within the RHF.

120kW of power was calculated on the assumptions below:

- 70kW for balance of stack standby operation at each train
- 50kW for security systems and lighting

These assumptions have been overestimated to ensure that adequate power is available for overnight operation. Fuel cells have been chosen for the overnight loads because:

- They have a longer shelf life compared to batteries
- Will last for the 25-year life of the facility
- Have a very low operational cost
- Operating at 120kW for 12 hours at night would deplete more than half of the battery storage which would be needed at the start of the day for RHF start up

With the availability of surplus hydrogen most of the year, they provide a suitable option for the overnight auxiliary loads. Sizing (and cost) would likely reduce after the design is further developed.

12.1.4 Solar Array Degradation

The degradation of all components must be investigated to ensure the life of the RHF over the specified period of 25 years. Solar degradation was calculated based on the solar panel warranty specifications provided by Sunpower of 2.5% loss in the first year of installation and 0.45% for each subsequent year [33].

Direct Power to Electrolysers

Figure 27 compares the maximum power of the solar array and electrolyser power requirements each year. As the electrolyser degrades, an increase of power is required to maintain equivalent levels of hydrogen production. In year 11 the electrolyser power requirement exceeds the solar array's output.

[33] Sunpower: Warranty for Performance: https://www.sunpower.com.au/sites/default/files/2020-01/535279_AU_PSERIES_P3_COM_Warranty_REVA.pdf

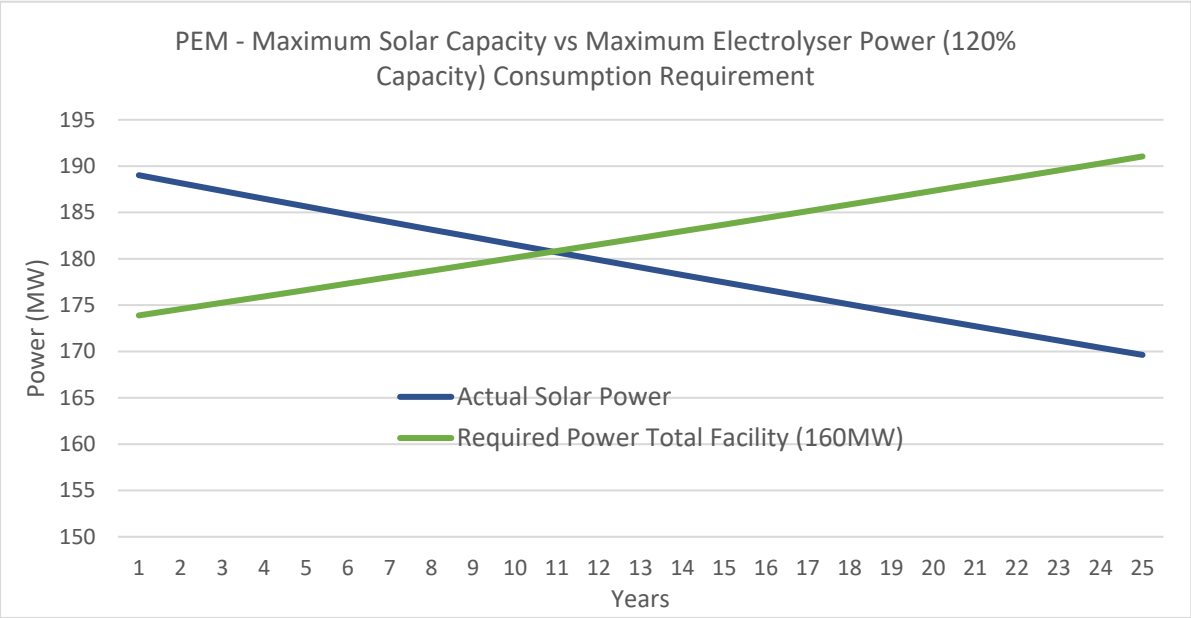


Figure 27: Electrolyser and Solar Power Degradation Comparison

To combat the effect of solar and electrolyser stack degradation, ANT proposes that every 5 years a subsequent 5MW of electrolysis and 6MW of accompanying solar be added to the RHF. Room for expansion has been allowed for in the layout design and in the cost modelling for the facility. Further optimisation for the allowance of degradation will be analysed in the next stage of detailed engineering.

Figure 28 compares the annual hydrogen produced by the facility from year 1 to 25. It can be observed that if degradation is not allowed for, there is a significant decrease in the total hydrogen produced. It also demonstrates that there is enough hydrogen in year 25 to service the DNM requirement with the solar and electrolysis additions.

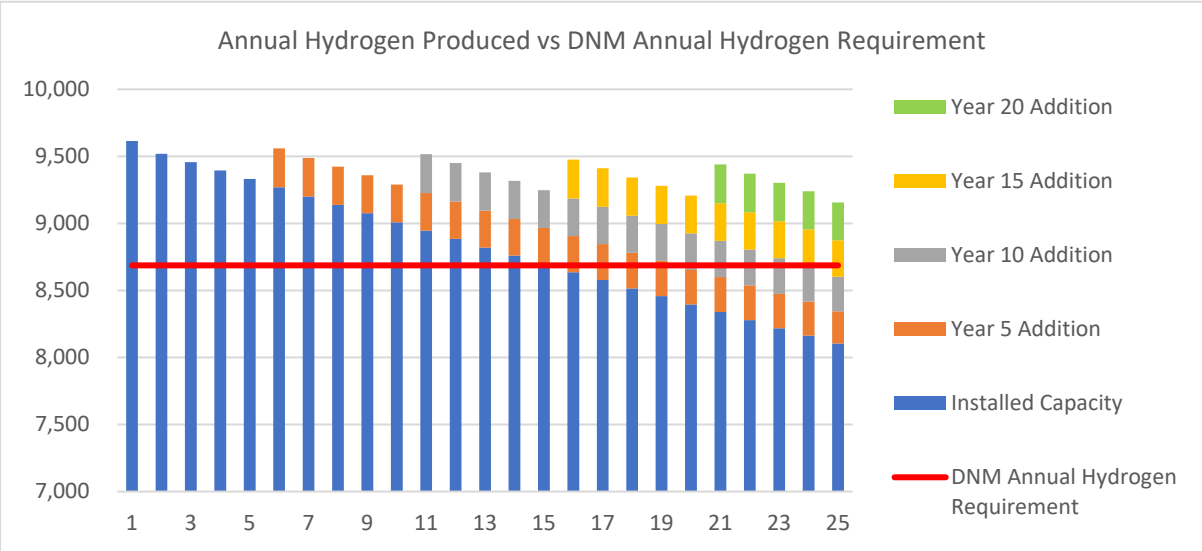


Figure 28: Year 1 to 25 Hydrogen Production Comparison

Note: Hydrogen production is nominal with no storage capacity constraints.

AC Auxiliary System

Figure 29 shows the power output of the solar array dedicated to the AC auxiliary system. Over the life of the RHF the total power lost for this system is 3.15MW. This loss in power will be overcome by installing 120kW of panels every year and this cost has been accounted for in the OPEX for the facility.

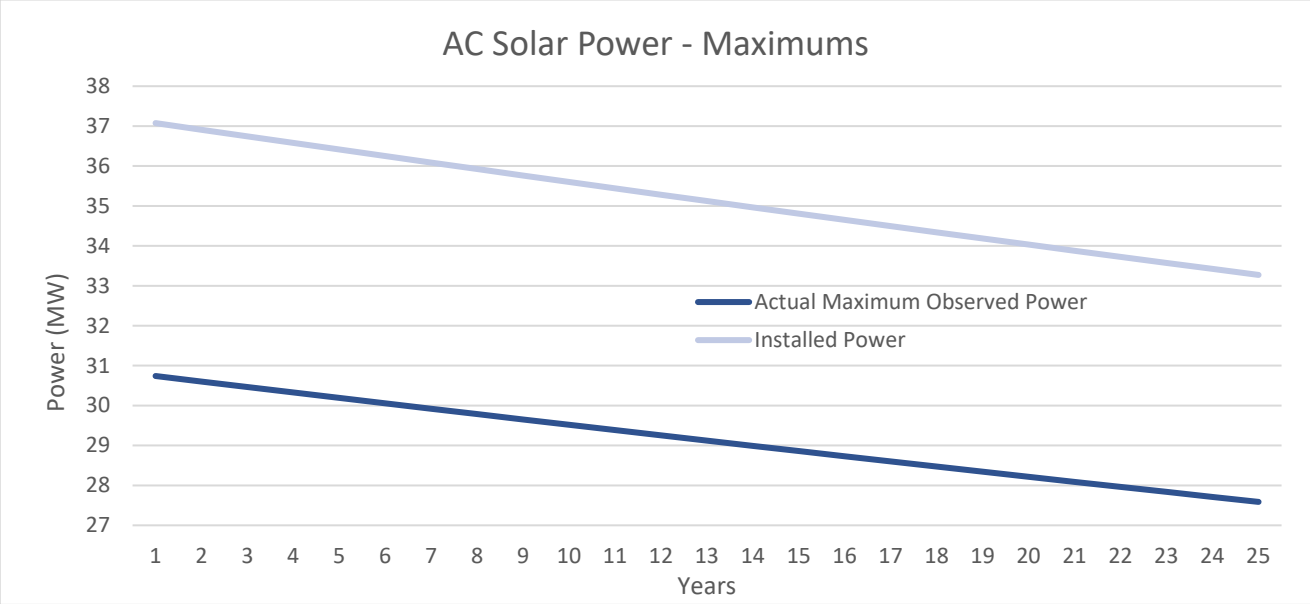


Figure 29: AC Solar Degradation

It is recognised that the proposed capacity additions for both DC and AC systems are conservative. In the next phase of the project, further optimisation of sizing and timing of solar generation capacity additions will be completed, lowering the overall CAPEX and/or OPEX costs.

12.1.5 Production Performance

Table 35 compares the total production performance of the DNM ammonia plant and the RHF for a year.

	MWh/year	MWh/t H_2	MWh/t NH_3
Power for Stack	466,000	48.5	8.5
Power for Auxiliaries	39,485	4.1	0.7
Power for ASU	6,720		0.1
Power for Synthesis	16,800		0.4
Total Power	**529,005**	**52.6**	**9.7**

Table 34: DNM Ammonia Plant and RHF Production Performance

The energy consumption is very close to the Australian average for ammonia production from steam methane reforming (36GJ/t of ammonia equals 10MWh/t).

12.1.6 Availability

Hydrogenics states three main maintenance requirements: periodic, annual, and long-term overhaul. Periodic maintenance can occur during operation of the facility and includes:

- Daily or weekly visual inspections of site and equipment
- Weekly verification that all process parameters (pressures, temperatures, levels, etc.) are within specification
- Monthly verification of any components with an expiry date
- Monthly visual inspection of valves, piping and tubing
- Monthly inspection of site safety items
- Quarterly filter inspections
- Quarterly visual inspection of all pressure relief devices
- Quarterly confirmation of correct functioning of safety and ventilation systems
- Replenish consumables as required

Annual maintenance requires shutdown and can be performed during the night hours when the facility is in standby or during periods in summer when hydrogen storage is full, and the electrolysers can be turned down/shutdown. Hydrogenics states that 1-2 days are required per 5MW electrolyser stack to perform the below tasks.

- Leak test hydrogen piping and tubing
- Check set points and calibrate all instrumentation (pressure, temperature, levels, etc.)
- Thermographic inspection of bus bars and other electrical components
- Inspect the hydrogen and oxygen pressure regulating valves
- Inspect and clean/replace all filters
- Change oil in DI water pumps
- Check glycol quality
- Service equipment per O&M manuals

Electrolyser utilisation equates to 4,339 hours per annum leaving 4,421 hours or 184 accumulative days for night-time maintenance. As there are 32 x 5MW stacks, 64 days of maintenance is required per year. Staggering the above tasks to fit within the night-time hours, all maintenance can be achieved.

Finally, long term overhaul which include:

- Refurbish the hydrogen and oxygen pressure regulating valves every 3 years (expected)
- Refurbish the DI Water Circulation Pump, per vendor recommendation
- Replace high cycling valves (per HYGS O&M manual) every 5 years (expected)
- Recertify all pressure relief valves every 5 years (mandatory)
- Replace desiccant in H_2 dryer every 5 years (expected)
- Stack refurbishment (by Hydrogenics) after ~80,000 operating hours (expected)

Long term overhauls will take place alongside the annual maintenance tasks except for the stack replacement which requires an estimated 1 day per stack provided that a spare stack is available, and the correct personnel and tools are present. If required, these replacements will take place during summer (when hydrogen production is greater than the DNM demand) or to coincide with DNM major maintenance.

12.2 Water Consumption

Electrolysis requires water to produce hydrogen. Theoretically, 8.9kg of water is required to produce 1kg of hydrogen. With contingency of 5% for any facility water losses, the water consumption becomes approximately 9.4kg of water per 1kg of hydrogen produced. Table 36 summaries the water consumption for both the RHF and the DNM ammonia plant. As a result of the RHF, there is an increase of 4% in total water consumption per year.

Water utilised by the RHF will be supplied by existing DNM ammonia plant. Currently DNM sources its water from the Sunwater Burdekin Falls Dam[34]. Annually this dam supplies water to farmers, urban water and industrial users equating to approximately 22.6GL of water. The RHF water usage represents a 0.4% increase in annual water usage for the Burdekin Dam.

	Water Consumption (ML pa)
DNM Ammonia Nitrate Plant	2,000
DNM Renewable Hydrogen Facility	82

Table 35: Water Consumption Comparison

[34] Sunwater Burdekin Falls Dam: https://www.sunwater.com.au/schemes/burdekin-haughton/

12. Metrics That Demonstrate the Competitiveness of Renewable Energy Supply to Large Scale Industrial Facilities

Modelling undertaken during the course of the study demonstrates that production of RH may be viable for a large-scale facility such as the RHF when compared to SMR with Carbon Capture and Storage (CCS) and coal gasification with CCS for both black and brown coal.

CSIRO's National Hydrogen Road Map[35] compares the cost of RH from PEM and alkaline with SMR and coal gasification as shown in Table 37.

Technology	2018 AU$/kg H_2	2025 AU$/kg H_2
Proton exchange membrane (PEM) electrolysis	6.08 - 7.43	2.29 - 2.79
Alkaline electrolysis	4.78 - 5.84	2.54 - 3.10
SMR with CCS	2.27 - 2.77	1.88 - 2.30
Black coal gasification with CCS	2.57 - 3.14	2.02 - 2.47
Brown coal gasification with CCS	-	2.14 - 2.62

Table 36: CSIRO National Hydrogen Roadmap - 2018

The CSIRO forecast for 2018 is based on 2016/17 figures and the 2025 forecast is based on a conservative reduction in CAPEX for PEM and alkaline. The PEM and alkaline forecasts are based on grid-connected renewables with 93% capacity factor.

The present study has found that PEM RH production cost can be reduced further for large-scale behind the meter RH. Table *38* summarises the forecast price for solar generated hydrogen over a 25-year period based on 2020 costings and forecast costings for 2022 and 2025.

	2020 AU$/kg H_2	2022 AU$/kg H_2	2025 AU$/kg H_2
RHF forecast for PEM	3.10 - 3.98	2.77 - 3.55	1.99 - 2.78

Table 37: Summary of Forecast Price for RH Produced by PEM including OPEX, CAPEX sustenance and finance over 25 years (excludes storage & transport costs)

The price per kilogram of hydrogen in 2020 is based on a forecast:

- Operational cost over 25 years
- Capital sustenance cost
- Finance cost
- Initial facility cost excluding hydrogen storage

The exclusion of storage was to enable the comparison against the CSIRO National Hydrogen Roadmap forecast. CSIRO's 2018 forecast for PEM was $6.08 - $7.43, whereas this study has established a 2020 cost of $3.10 - $3.98, representing an approximate reduction of 50% in two years. This reduction is attributed to the following:

[35] CSIRO's National Hydrogen Road Map: https://www.csiro.au/en/Do-business/Futures/Reports/Hydrogen-Roadmap, pages 13 & 20

- Improved power system efficiency
- Further reduction in cost of solar installation per Watt installed
- Further reduction in cost per MW of installed electrolysers
- Industrial project scale (e.g. >100MW)
- Local design improvements for the BOP

Similar costs for PEM RH are forecast by both the CSIRO and the present study. This study indicates that a potentially lower cost per kilogram of hydrogen could be achieved than forecast in the CSIRO study, making PEM RH potentially competitive with alternative production methods (based on CSIRO's forecasts in Table *39*.

Technology	**2025 CSIRO Forecast AU$/kg H_2**	**2025 Study Forecast AU$/kg H_2**
PEM electrolysis	2.29 - 2.79	1.99 - 2.78
Alkaline electrolysis	2.54 - 3.10	-
SMR with CCS	1.88 - 2.30	-
Black coal gasification with CCS	2.02 - 2.47	-
Brown coal gasification with CCS	2.14 - 2.62	-

Table 38: CSIRO vs RHF Optimisation Forecast

Figure 30 demonstrates the current competitive advantage of SMR and coal gasification without a premium for emissions reductions or elimination (e.g. Grey Hydrogen GH, no carbon capture) . The cost equivalent per kg for GH ranges between $0.70 and $2.25 depending on gas price. At the current contract price at Moranbah GH can be produced for less than AU$1.50 (refer Figure 30). At this price RH is not competitive.

However, the ASX future gas prices for Wallumbilla[36] indicates a future spot price of AU$10.10/GJ in the June 2024 quarter. Based on the graph below this would translate to an energy cost of hydrogen of between AU$1.70 - 2.30 from SMR without carbon capture and storage (CCS). Based on this study RH starts to become competitive with GH from SMR with an estimated cost per kilogram by 2025 in the range of $1.99 to $2.78 if the spot price is used.

[36] ASX Futures Gas Prices:
https://www.asxenergy.com.au/futures_gas

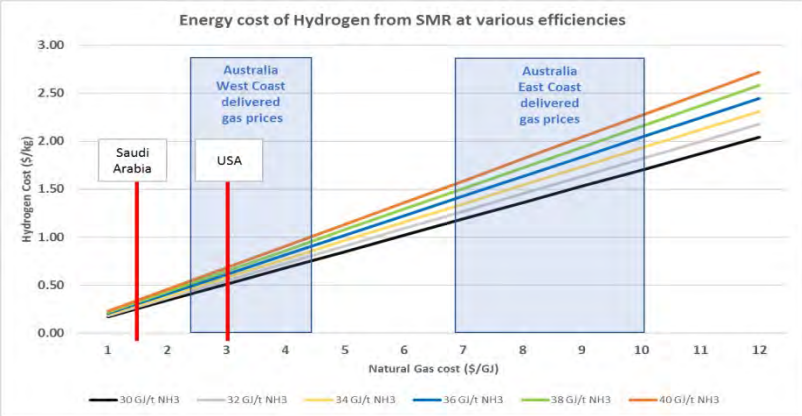


Figure 30: Energy Cost of Hydrogen from SMR at Various Efficiencies

The authors recognise that the spot price (Wallumbilla Natural Gas Calendar Quarter Futures) is usually higher than the contractual price for large industrial customers.

At $1.50/kg RH would be economically competitive with GH (i.e. hydrogen generated by SMR using contracted gas). A price of less than $1.50/kg for RH may be achievable by 2030 through further cost reductions in both renewables and PEM electrolysis.

On a pure cost basis, as shown above, GH could be competitive with blue hydrogen (SMR including CCS) after 2025 and GH by 2030. Expanding the basis of assessment to include change in:

- Consumer purchase demand (towards renewable energy)
- Regulation (taxes on SMR / hydrogen from SMR)
- Rebates for renewable hydrogen

RH could potentially be competitive within an earlier timeframe.

13. Cost of Hydrogen Drivers, Commercialisation Drivers and Sensitivities

The RHF in its current configuration utilises BTM solar. An alternative is to source renewable energy from the grid. The following analysis compares the two options to determine which is more viable.

Viability has been assessed based on the cost of H_2 per kilogram or LCOH for each option. The factors that influence the LCOH are:

- Cost of power
- Capital cost
    - Electrolyser
    - Renewable energy
    - Storage and transport
    - Capital sustenance
    - Balance of plant
    - Electrical infrastructure
- Operational cost
- Maintenance cost
- Taxation - Depreciation

The analysis is based on today's costing and concludes that green power from a dedicated renewable source (BTM solar) has a lower LCOH compared to renewable grid power. Today's costing assumes no reduction in the listed cost factors. A future reduction in cost factors is more likely for BTM solar than for renewable grid power, potentially making BTM solar more economical. Current forecasts expect the power generation cost to be approximately AU$40/MWh in QLD[37]. Based on the extra cost associated with distribution, it is extremely unlikely that a grid connected PPA agreement would be less than $60/MWh. In fact, it is more likely to be higher than the $60/MWh forecast in the CSIRO report in 2018[38].

Comparatively this study estimates that the amortised energy cost for the base case BTM system is $32/MWh, with approximately $11/MWh associated with operational costs. Incorporating the cost reductions identified for 2022, the cost reduces to $29/MWh. The operational cost represents over 1/3 of the total cost of energy, highlighting another opportunity to further reduce energy cost through optimisations in plant operations (i.e. automation).

[37] AXS – Power Market:
https://www.asxenergy.com.au/#qld
[38] CSIRO Hydrogen Roadmap – Powe Prices:
https://www.csiro.au/~/media/Do-Business/Files/Futures/18-00314_EN_NationalHydrogenRoadmap_WEB_180823.pdf?la=en&hash=36839EEC2DE1BC38DC738F5AAE7B40895F3E15F4, page 15, table 3

Figure 31 outlines the major contributing factors and overall LCOH for a grid connected system compared to BTM system which supplies 23.8tpd of RH to the Dyno Nobel facility. The BTM system utilises the design outcomes for the RHF and the grid connected system is based on the following assumptions:

- 60MW of AC connect electrolysers (assumes 95% utilisation at 100% nominal electrolyser capacity output)
- 16 tonnes of storage and piping for the continuous supply to DNM
- Auxiliaries and main office space
- A grid power cost of $60/MWh
- Power required for total system is 55kWh per kg of hydrogen produced
- Electrolyser replacement every 9 years (due to increase utilisation)

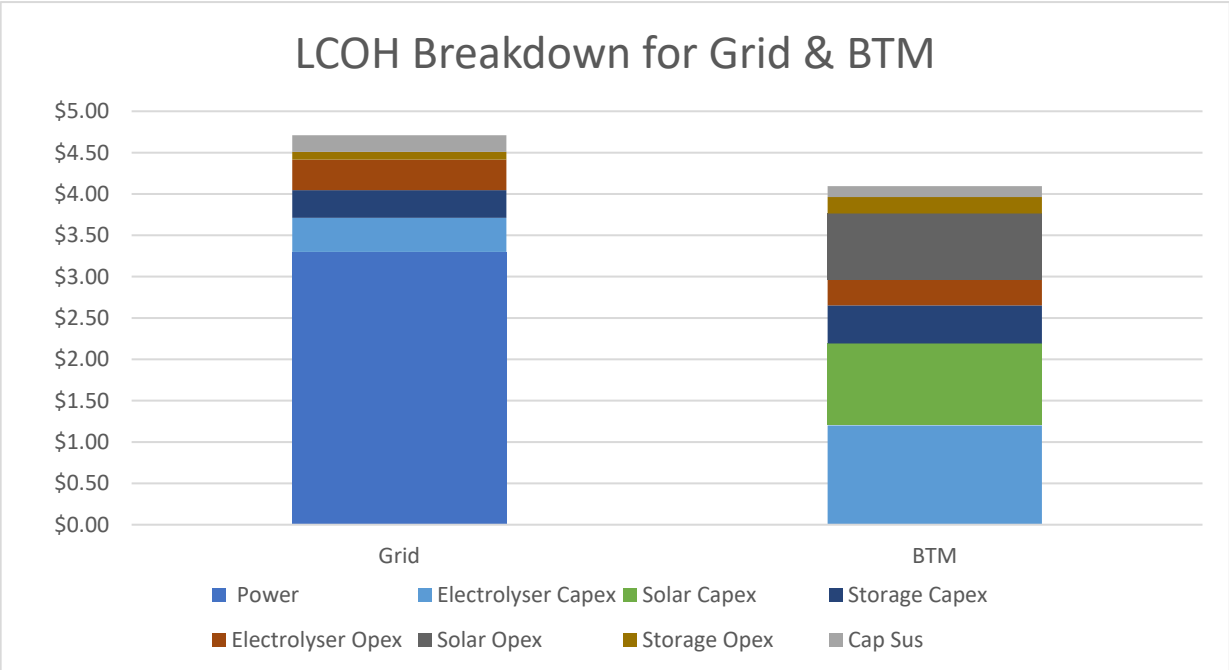


Figure 31: LCOH Breakdown for Grid & BTM

Figure 31 demonstrates that BTM result in a lower LCOH. Each contributing factor for each system is examined in further detail below.

For a grid connected system the major influencing factor in the LCOH is the cost of power. Conversely, for a BTM system the largest contributing factor is CAPEX due to increase componentry sizing required.

Renewable Grid-Connected Power

The key cost factors for the LCOH calculations are outlined below.

Cost of Renewable Grid Power

Grid connection provides 24/7 power resulting in higher electrolyser utilisation and, in turn a reduction in electrolyser capacity to produce the equivalent amount in hydrogen. However, a disadvantage to this design approach is the high cost of energy (per MWh). Currently, renewable

grid power prices range between AU$20 – 110/MWh significantly influencing the LCOH. Understanding that the high and low range price will not occur for significant time periods, an average price of AU$ 60/MWh will be assumed for the present analysis. CSIRO's roadmap provides for a LCOH of AU$6.60/kg in 2018 based on the renewable grid price of AU$60/MWh.

A 60 MW electrolyser system utilising renewable grid power will produce the required 23.8tpd compared to the BTM system which requires 160MW. Using the RHF forecast cost for this project and removing the solar and reducing hydrogen storage component from 52 to 16t (allowing for 1-day buffer), results in CAPEX of AU$2.8M/MW of electrolysis for the 60MW system. Comparatively, the BTM system CAPEX is AU$4.0M/MW of electrolysis.

The LCOH at a range of power costs is shown in Figure 32, based on operating the electrolyser at 95% for 365 days per year (allowing for maintenance). Figure 32 includes a sensitivity analysis of ±20% of the estimated total system cost.

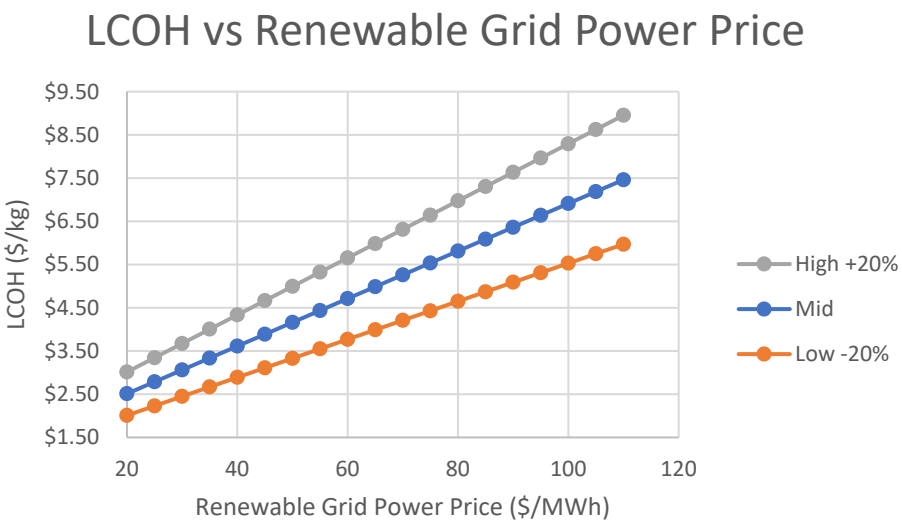


Figure 32: LCOH vs Renewable Grid Power Price

Figure 32 outlines a linear relationship between renewable grid power price and LCOH. Within the CSIRO forecast power price range, the LCOH does not fall below $1.50/kg assuming the current system cost estimate of ±20% of $2.8M/MW installed CAPEX cost. At $60/MWh the LCOH is forecast to be $4.71 which is greater than $4.09/kg for the BTM system.

Table *40* compares electrolyser cost reduction to LCOH for power prices in 2020 and 2022.

Reduction in installed electrolyser cost	LCOH assuming Grid power at $60/MWh (2020)	Reduction in LCOH for $60/MWh (2020)	LCOH assuming Grid power at $50/MWh (2022)	Reduction in LCOH for $50/MWh (2022)
(%)	($/kg)	(%)	($/kg)	(%)
0	4.71	0	4.09	0
25	4.27	3.2	3.80	2.8
50	4.13	6.3	3.70	5.3
75	3.99	9.5	3.59	8.2

Table 39: Electrolyser Cost Reduction

The LCOH is more sensitive to the grid power price than the cost of major equipment. For example, reducing electrolyser cost by 75% results in a 9.5% LCOH reduction based on a $60/MWh price in 2020. Achieving a 9.5% LCOH reduction requires a 14% reduction in renewable grid power prices from $ 60/MWh to $51.59/MWh, based on a $4.71 LCOH.

Capital Sustenance

The electrolyser stack will require refurbishment every 9 years due to the higher utilisation. Higher utilisation equates to a capital sustenance of AU$107.9M over the 25-year period representing 3.3% of the total cost. This represents a 163% increase in the capital sustenance compared to BTM (AU$41M).

14.1 Behind the Meter Renewable Power

Alternatively, electrolysers in suitable locations can be connected to dedicated renewable sources on site such as solar and wind – for present purposes BTM solar. BTM solar results in lower electrolyser utilisation and, consequentially, larger solar and electrolyser capacity. This option has a significantly higher initial capital cost than a grid connected system, but a significantly lower operating cost as most of the energy cost is paid up front.

The LCOH of $4.09/kg for BTM utilises the 2020 RHF engineering design and costings. The LCOH of $3.49/kg for BTM in 2022 is based on the forecast reduction in cost of components from the potential optimisation identified in section 18.

Tables 41 - 43 show the impact on LCOH of cost reductions in key cost factors, namely storage & transport, electrolysis and solar. Unlike the grid connected system, the significant influencing factors of the LCOH for BTM is the capital cost of the major components.

Storage & Transport

Reduction in installed storage cost	LCOH BTM (2020)	Reduction in LCOH (2020)	LCOH BTM (2022)	Reduction in LCOH (2022)
(%)	($/kg)	(%)	($/kg)	(%)
0	4.09	0	3.49	0
25	4.00	2	3.40	3
50	3.92	4	3.31	5
75	3.83	6	3.22	8

Table 40: Electrolyser Cost Reduction to LCOH for Storage & Transport in 2020 and 2022

Electrolyser

Reduction in installed electrolyser cost	LCOH BTM (2020)	Reduction in LCOH (2020)	LCOH BTM (2022)	Reduction in LCOH (2022)
(%)	($/kg)	(%)	($/kg)	(%)
0	4.09	0	3.49	0
25	3.84	15	3.29	6
50	3.58	21	3.08	12
75	3.33	28	2.87	18

Table 41: Electrolyser Cost Reduction to LCOH for Electrolyser in 2020 and 2022

Solar

Reduction in installed solar cost	LCOH BTM (2020)	Reduction in LCOH (2020)	LCOH BTM (2022)	Reduction in LCOH (2022)
(%)	($/kg)	(%)	($/kg)	(%)
0	4.09	0	3.49	0
25	3.84	15	3.29	6
50	3.60	21	3.08	12
75	3.35	27	2.87	18

Table 42: Electrolyser Cost Reduction to LCOH for Solar in 2020 and 2022

In the grid connected scenario a 75% reduction in major capital equipment cost results in a 9.5% reduction in LCOH. In the BTM scenario a 75% reduction in the storage & transport, electrolysis and solar results in a LCOH reduction of 11%, 28% and 27% respectively. The potential cost reductions for each of the components for BTM has a larger impact on LCOH than all the capital components combined for the grid connect scenario.

Combined Reduction in: Storage & Transport, Solar and Electrolyser

Reduction in installed equipment cost	LCOH BTM (2020)	Reduction in LCOH (2020)	LCOH BTM (2022)	Reduction in LCOH (2022)
(%)	($/kg)	(%)	($/kg)	(%)
0	4.09	0	3.49	0
25	3.50	22	2.99	14
50	2.91	35	2.48	29
75	2.33	48	1.98	43

Table 43: Electrolyser Cost Reduction to LCOH for All Components in 2020 and 2022

Cost reductions for the cost factors in the BTM scenario will not occur independently of each other. Therefore, Table 44 highlights the effect of simultaneous cost factor reductions on the LCOH. Simultaneous reductions of 75% will result in a 48% decrease in the LCOH for the BTM.

There is a high likelihood that solar, electrolysis and storage & transport costs will reduce more than 25% reduction over the next 5 years. On the other hand, grid power costs are less likely to decrease over the same period. Any reduction in costs of renewable components are likely to be outweighed by the cost of distribution and required green off-sets to enable 24/7 operation.

14. Commercialisation Pathway for the Production and Deployment of RH from Current Production Methods

The results of the study have found that under current market conditions, the project is not feasible without at least 50% grant funding. Pathways to commercialisation for renewable hydrogen in industrial use will require significant reductions in the LCOH. There are numerous ways this can be achieved:

- Reduction in renewable energy input costs
    - Grid-Connected - Leveraging underutilised investment in renewables generation to secure low power prices (e.g. less than $20/MWh)
    - BTM - Reduction in capital and operational costs
- Reduction in total installed capital cost (through equipment, installation, automation, etc.)
- Market acceptance of price premiums for industrial products produced from renewable energy (e.g. customer demand or regulatory requirements)
- Increased demand for RH into high value domestic applications (e.g. transport)

In the absence of large-scale market intervention, large scale investment in RH for industrial use will remain unattractive until one or more of the factors above change to a point where there is a realisable business case.

Globally governments are providing significant financial and regulatory support for the development and uptake of RH to overcome the market failure. Government support in the form of grants, concessional finance and equity investment of some combination could also provide a more rapid path to commercialisation. The benefits in return would be:

- Demonstrate to potential export markets Australia's capability to meet demand
- Provide a demonstration vehicle for future plant and investment in RH production in Australia
- Set a path to reducing CAPEX and OPEX for future projects by trialling and demonstrating potential technologies and methodologies at the plant
- Train and up-skill the workforce for the hydrogen supply chain and future projects
- Establish Australia as one of the first movers in the renewable hydrogen supply chain
- Attract large scale investment to the hydrogen economy in Australia
- Generate employment growth and export opportunities for Australia

The timing for achieving step change reductions of any of the above items is dependent on multiple domestic and international factors meaning that predicting a timeframe for commercial realisation in Australia is difficult. In the absence of clear government support and changes to legislation/regulation, it is unlikely that RH will be a commercially viable replacement for grey hydrogen in industrial applications before 2030.

15. Detailed Financing Plan Options for the Project that are not Commercial in Confidence

Based on the business case and financial modelling, financing for the project requires a minimum of three parties:

- Dyno Nobel to provide a long-term take-or-pay RH offtake contract that underpins the revenue and 'bankability' of the project
- One or more owner(s) of the RHF who would contribute equity towards the cost of construction
- One or more providers of grant funding to bridge the gap in minimum equity returns

Multiple private companies have shown interest in providing equity funding for the project as long as minimum rates of return can be achieved. While the rates vary, figures as low as 5% were discussed. Based on the taxation impacts, only large profitable organisations are likely to be credible RHF owners. This presents both benefits and challenges as these organisations are often able to contribute expertise to aspects of design or operation, however they are typically quite conservative and potentially risk averse.

Grant funding is potentially available from several sources, including Australian State and Federal Governments, international Governments (such as Japan and Germany) and some large corporations. Given the scale of funding required, it is expected that a combination of sources would be required. It is noted that at the time of this study the grant funding requirement was far in excess of the funding on offer in Australia. In the absence of significantly greater funding being made available, it is unlikely large-scale (>100MW) RH developments will progress in the near term.

It is notable that a party providing concessional debt funding is not included in the financing plan. This is due to the very low cash returns on investment achieved when producing RH at AU$2/kg. The financial modelling for the project has shown that the cash generation does not support debt financing, even at interest rates as low as 3%.

The project could potentially be feasible and funded with minimal (or even zero) grant funding if significant RH offtake can be secured at higher prices. With RH already reported to be an economic diesel replacement for heavy vehicles, it is credible that additional customer(s) could be secured who could pay AU$6/kg for RH. The lack of RH demand is currently the impediment to this occurring and at the time of this study, the 800tpa of available surplus RH was far in excess of local transport demand.

Table 45 compares six possible scenarios relating to various capital and revenue options to assess a viable solution to progress to the next stage of the project.

Option	Scenario	CAPEX	Government Support Required		Pre-Tax IRR	Post-Tax IRR
		(AU$M)	(%)	(AU$M)	(%)	(%)
1	DNM sales only, current CAPEX	674	59	395	-6.6	5
2	DNM sales only, future CAPEX	556	57	316	-5.9	5
3	Excess H_2 at $6, current CAPEX	674	40	267	-1.6	5
4	Excess H_2 at $6, future CAPEX	556	34	187	-1	5
5	DNM volume at $3.56, future CAPEX	556	0	0	2.1	5.8
6	4kt H_2 at $6, future CAPEX	556	0	0	1.4	5

Table 44: Financial Modelling Summary

The assumptions underpinning the options include:

- Hydrogen price to DNM of $2/kg adjusted over 25 years for the increase in OPEX
- Excess /transport hydrogen price of $6/kg
- 2020 CAPEX costings (Options 1 & 3)
- 2022 CAPEX costings, which include optimisations to the technologies used and engineering design (Options 2, 4, 5 & 6)
- Grant funding set to achieve a post-tax IRR of 5% (Options 1, 2, 3 & 4)
- DNM RH volume of 8,408tpa, excess volume of 992tpa

Options 1 - 4 show the level of grant funding required under various revenue and CAPEX cases that meet the DNM business case. Option 5 demonstrates the potential future viability of the current design in meeting the developing export and domestic markets. However, in the short to medium term there is no significant market willing to pay the forecast export and domestic cost per kilogram of hydrogen used in the modelling of Option 5.

Option 6 demonstrates the quantity of high-value (AUD$6/kg) domestic off-take required to obtain the minimum 5% after-tax IRR. This reduces the supply to DNM to 5.7ktpa at $2/kg. This also assumes no government funding.

To address the short to medium term market failures, government support is required to build up the capability and knowledge to de-risk engineering and investment into the future Australian hydrogen economy.

Government support is also required to develop an export market as it is unlikely that importers of renewable hydrogen will enter into a long term (e.g. 25 year) off-take agreement of AU$3.56/kg. This price is based on the target price from Japan by 2030 of ¥330/kg, which is further forecast to be ¥220/kg in the longer term (~AU$2.40).

Debt can be introduced into the model once the pre-tax IRR is 2% or greater (achieved through a combination of pricing and grant funding). Introducing debt while the pre-tax IRR is below 2% will have a negative impact on returns. The higher the pre-tax IRR is above 2%, the more advantageous the introduction of debt will be. To achieve pre-tax IRR's greater than 2 there must be a domestic market willing to pay the indicative wholesale mobility price of $6/kg.

16. Innovations in Design Integration & First-of-a-kind Outcomes and Potential Future Optimisations

Innovations from the study were in four main areas:

- DC/DC Integration
- Electrolyser control system
- RHF Sizing Modelling – Electrolyser, Solar and Hydrogen Storage
- Electrolysis equipment BOP integration

DC/DC Integration

DC/DC solar electrolysis is designed to reduce power consumption and capital costs. Solar cells generate power at a comparatively high voltage and low current to that required for electrolysis (typically lower voltage and higher current). In traditional grid-connected systems the power generated from the solar panels is converted four times, firstly by converting the DC current to AC at low voltage with an inverter, then by increasing the voltage in a transformer, then decreasing the voltage in another transformer before finally the power is converted back to DC in another inverter. The DC/DC system employs direct DC coupling to eliminate the need to convert DC power from the solar panel to AC and back to DC for the electrolyser, resulting in an increase of power of 3% and a cost reduction due to reduced infrastructure. For this project, the capital saving is estimated as AU$28.2M.

A first of kind DC/DC converter for the electrolyser will be installed. SMA's DC/DC buck converter is currently designed for battery charging. However, for this project SMA would configure the DC/DC converter to be customised to match the power requirements for electrolysis. It will act like a conventional DC/DC buck converter; essentially working to charge a 'battery' with an unlimited capacity. Redeploying existing power technology for this novel application means a solution is readily available and provides significant cost savings over developing entirely new equipment and supply chains. Buck converter technology is available from a number of manufacturers.

Electrolyser Control System

This RHF will be the first of its kind in the world by size and operation. The system is designed to ramp up in parallel with the increase in available solar energy during which time hydrogen production will be monitored across the four individual trains. The RHF will be controlled by a master controller in the office/warehouse building which also serves as an information transfer hub to DNM. The master controller will centralise all supervision of each of the four electrolyser train PLCs. Each electrolyser PLC will control and monitor 8 individual electrolyser skid PLCs.

Under normal production all hydrogen will be transferred to the DNM facility via the ring main. Once nominal DNM offtake rates are achieved, any additional hydrogen produced will be diverted to the compressors for storage at the tank farm. When hydrogen production falls below the hourly requirement to DNM, this loss in hydrogen will be serviced by the stored hydrogen from the tank farm.

The integration between solar power generation, electrolysis production and hydrogen storage will be the first of its kind, controlling the communication between the master controller, the four train PLCs, the tank farm PLC and the AC system. This architecture controls overall production dynamically to accommodate the variable energy input due to seasonality, inclement weather events and the lack of overnight power.

RHF Sizing Modelling – Electrolyser, Solar and Hydrogen Storage

As the electrolyser ages, one or more components of the balance of stack or balance of plant will indicate that the system requires refurbishment. For example, the thermal control system will no longer be able to reject sufficient heat to operate at full design rate, or the DC/DC rectifier will no longer be able to provide the required current and power to the stack. Planning in advance for long-term stack degradation by ensuring auxiliary systems are sized for the expected degradation (or have modular capacity additions pre-designed) enables the operating life of the asset to be extended. Minor investment upfront in capacity optimisation means no replacement of the stacks will be required and as a result there is a reduction in stack refurbishment expenditure of up to AU$70M.

Determining the 'bankable' hydrogen production from a facility with a variable renewable energy supply is difficult. As part of this study, ANT has developed a modelling tool that is able to integrate multiple sub systems of the RHF to work together to create an estimation of the operating conditions of the facility. The model showcases a typical year as a result of an analysis on 12 years of previous weather data. Consequently, there will be times where more or less hydrogen is produced. The model utilises solar irradiance data to create a solar output profile which is then combined with the operating conditions of the electrolyser and a hydrogen output is created for hourly intervals. This hydrogen profile is then used to create a hydrogen storage model that ensures delivery of hydrogen to DNM 24/7 all year round. This model can be deployed for alternate weather data or electrolyser performance parameters to very quickly determine the impacts in annual hydrogen production and optimum storage to meet predefined customer requirements (such as DNM's zero hours of zero supply requirement).

Electrolysis Equipment BOP Integration

BOP has been optimised in the design to reduce overall capital cost whilst considering the specific site conditions at Moranbah.

The electrolysis system design comprises four modular electrolyser trains distributed around the solar farm at the site. Each train comprises a modular design of multiple stacks sharing common BOP. The objective of the design is to reduce BOP cost and improve efficiencies with, for example, cooling systems and purifiers. The 40MW trains will be the first in the world to adopt this strategy for this size of facility.

Distribution of the electrolysers at the skid level throughout the solar array would be the optimal design to reduce the cost of cable runs and power losses. Conversely, creating a single central electrolyser facility would be the optimal design to reduce the cost of the BOP but would significantly increase the cost of cabling and power losses. The distribution of the four trains throughout the solar array was chosen to optimise the cost of both the DC cabling runs and the BOP. This is a trade-off between the cost of cabling and the cost of the BOP.

The additional benefit of four independent facilities allows for complete redundancy within the RHF. If one train were to shut down, the remaining trains will still be able to operate.

Requiring the BOP to be manufactured locally, ANT has designed and sought independent validation to drive down costs by eliminating transport costs and import duties. As a result, ANT has been able to add a local content contribution of 29% equating to AU$195.5M. A further aim is to establish a domestic supply chain to increase local skills and create new job opportunities. A local skilled workforce and supply chain will then be available for maintenance services to the RHF and future RH projects.

The primary auxiliary power source for overnight operation at the electrolysis trains will be via fuel cells. Even though there will be a battery system implemented to complement the AC system, the overnight load would drain the batteries, with insufficient power remaining for morning facility start up. With a hydrogen source already available, long operational life and low maintenance, the fuel cells serve as a suitable option for the longer duration predictable loads experienced overnight.

16.1. Potential Future Optimisations

It is expected that various aspects of the RHF design will be further optimised during the FEED stage of the project. Future optimisations may lead to improved designs of RHF sub-systems providing benefits such as more efficient/safer O&M of the facility as well as reductions in CAPEX and/or OPEX costs. A few examples of key opportunities to further optimise the RHF during the FEED stage are listed below:

Component / System	Opportunities for Optimisation	Est. Cost Reduction
Solar PV Modules	- Higher nominal power PV panels (e.g. 450/460/480W) with a delivery window of mid-2020 to mid-2021 which could include the next generation shingled mono-PERC modules, or even bifacial modules.	16% (AU$39M)
	- Increase the module string length (e.g. 28+ modules per string).	TBD not taken into account for 2022 forecast
	- Installation on prefabricated support frames or prefabricated solar arrays (e.g. Maverick/MAV array blocks from 5B[41]).	TBD not taken into account for 2022 forecast
	- Alternative solution to mounting panel frames compared to common practice of steel piling (e.g. mounted on recycled material sleepers).	TBD not taken into account for 2022 forecast
	- Increased automation in installation (structures, panel install and cabling).	TBD not taken into account for 2022 forecast
	- Panel washing by robotic (autonomous) cleaning machine.	Potential to reduce OPEX not taken into account for 2022 forecast
	- Supplementary solar power generation from rooftop panels on the electrolyser buildings.	TBD not taken into account for 2022 forecast
	- Minimise shading on panels from buildings by reducing the building height. This will also reduce the offset distance to the solar arrays.	TBD not taken into account for 2022 forecast
PV Module Trackers	- Alternative single-axis tracker technology.	TBD not taken into account for 2022 forecast
	- Trackers that are AC powered driven from decentralised AC grid instead of from the RHF AC auxiliary power system ring main.	TBD not taken into account for 2022 forecast
Power Conversion	- Cooling for DC/DC Converter enclosures to minimise de-rating of equipment due to high operating temperatures.	TBD not taken into account for 2022 forecast
	- Investigate power conversion hardware technologies that may be able to provide	TBD not taken into account for 2022 forecast

[41] Maverick – 5B: https://5b.com.au/

	DC/DC as well as DC/AC at each electrolyser train.	
	- Look to optimise the size of DC/DC converters (e.g. lower power units may be suitable).	TBD not taken into account for 2022 forecast
	- Look to optimise the size of battery storage. Battery storage could be reduced depending on the load profile.	TBD not taken into account for 2022 forecast
AC Auxiliary Power	- Decentralised auxiliary power generation rather than a ring main arrangement.	54% (AU$17M)
	- Assess alternatives for energy storage - Battery technologies (e.g. Tesla Megapack[42]) - Solar/Thermal battery storage such as Raygen[43].	TBD not taken into account for 2022 forecast
	- Aux. power loads may be lower so the size of the aux power system can be reduced.	Included above but can be further optimised
	- The DC system could be used to supply the large motor loads using modified VSD (variable speed drive) known as an AFE (Active Front End) technology[44].	Included above but can be further optimised
Electrolyser Trains	- Larger Electrolyser Stacks and optimisation of skid BOP to drive down unit cost or	15% (AU$29M)
	- Distributing the skids/reducing the train size (e.g. from 40MW to 20MW) and spreading amongst the solar farm to reduce cabling.	TBD not taken into account for 2022 forecast
	- Increasing the electrolyser stack pressure (since the stack is rated for a MAWP of 40 bar).	TBD not taken into account for 2022 forecast
	- Higher operating temperature for the electrolyser (e.g. inlet water at 45-50 deg.C) to reduce cooling loads.	TBD not taken into account for 2022 forecast
	- Alternate ventilation systems to improve hydrogen escape from the building. Consider passive/wind-driven turbine roof ventilators to remove hot air and hydrogen from the buildings without having any electric motors or connections.	TBD not taken into account for 2022 forecast
	- Alternate low-power cooling systems to maintain the building at an optimal temperature during the hotter months of the	TBD not taken into account for 2022 forecast

[42] Tesla Megapack: https://www.tesla.com/megapack
[43] Raygen: https://raygen.com/
[44] Vacon NX: http://files.danfoss.com/download/Drives/Vacon-NX-Active-Front-End-ARFIFF02-Application-Manual-DPD00905B-UK.pdf

	year.	
	- Review the design of the hydrogen venting system (i.e. the number and size of ventilation fans and the arrangement of the ducting).	TBD not taken into account for 2022 forecast
	- Fire system utilising a gaseous fire suppressing agent (e.g. CO_2 or Halon 1301) for enclosures.	TBD not taken into account for 2022 forecast
	- Harvesting additional solar power by installing more panels on the building roof/walls.	TBD not taken into account for 2022 forecast
	- Nitrogen generation plant instead of using compressed Nitrogen cylinders.	TBD not taken into account for 2022 forecast
	- Reduce hydrogen venting losses. Consider a closed loop hydrogen drying system rather than venting hydrogen as part of the regeneration process. Carry out a detailed cost-benefit analysis of the closed loop system taking into consideration CAPEX/OPEX.	TBD not taken into account for 2022 forecast
	- Overnight loads could be reduced to minimise the fuel cell sizing or utilise batteries.	TBD not taken into account for 2022 forecast
	- Having a single control system for 8 electrolysers per train rather than 8 separate PLCs.	TBD not taken into account for 2022 forecast
	- Consolidating the equipment from the Control Building into the Electrolyser Building thus removing the need for a separate building.	TBD not taken into account for 2022 forecast
	- Consider 40ft containers or portacabins for the Control Building rather than a purpose-built structure.	TBD not taken into account for 2022 forecast
	- Water storage could be reduced by eliminating the need for one or more water tanks, or by utilising smaller tanks.	TBD not taken into account for 2022 forecast
	- Rainwater tanks could be used to supply the fire water system.	TBD not taken into account for 2022 forecast
	- Review requirement for overhead cranes in buildings. Design of building and equipment layout may allow for 'skating' of electrolyser packages rather than lifting.	TBD not taken into account for 2022 forecast
Hydrogen Pipelines	- Review costs and benefits for below-ground vs above-ground hydrogen transportation pipelines.	TBD not taken into account for 2022 forecast
	- Consider lower-cost installation concepts such as ground-mounting on low-cost recycled	TBD not taken into account for 2022 forecast

	composite (RFP) railway sleeper pipe supports.	
Hydrogen Tank Farm	- Reduce the number of tanks by investigating alternative hydrogen storage technologies (e.g. Type 4 all-carbon horizontal tanks, Hortonsphere[45] pressure vessels, metal-hydride containers, Hexagon[46] 'Titan' Tanks, below-ground storage, etc.).	30% (AU$33M)
	- Different temperature/pressure combinations for storage tanks.	Included above but can be further optimised
	- Install fire walls between tanks rather than a water spray/monitor fire system.	TBD not taken into account for 2022 forecast
	- Assess alternative compressor and aftercooler equipment.	TBD not taken into account for 2022 forecast
	- Hydrogen compressors powered by DC motors.	TBD not taken into account for 2022 forecast
Ancillary / General	- Investigate pumping wastewater to DNM sewerage treatment plant rather than having septic tank systems at the electrolyser buildings and the main office.	TBD not taken into account for 2022 forecast
Total Potential Savings		**AU$118M**

The length of this list reflects the maturity of the design and highlights the lack of project examples available from which best available technology can be drawn. The DNM renewable hydrogen project presents an opportunity to develop significant "first of type/first of kind" lessons that will significantly aid the development of future projects, especially those seeking to utilise BTM renewable energy supplies.

This project, if successfully deployed would also allow learnings on how to improve operational cost of such a plant. As operational cost estimates for large scale solar facilities varied widely, a conservative approach was taken in this study towards this cost which added greater than $6.5 million per year to the operational budget. This could be potentially reduced by 50% through operational learnings and new technology advancements.

A pathway for renewable hydrogen without subsidies is to incorporate the above potential learnings in plant design, capital equipment cost and operational cost improvements that would be derived from deploying projects such as this in Australia.

Combining the reduction in cost with an increase in domestic market size for higher value renewable hydrogen will help fast-track widespread development of large volume facilities between now and 2030.

[45] MCDERMOTT – Hortonsphere: https://www.mcdermott.com/Markets-Served/Industrial-Storage/Storage-Tanks-Vessels/Hortonsphere-Pressure-Vessels
[46] Hexagon: https://www.hexagonlincoln.com/hydrogen/hydrogen-products/hydrogen-products

17. Key Project Implementation Lessons Learned

17.1. Commercial Feasibility

18.1.1 Renewable (Green) Hydrogen vs SMR (Grey) Hydrogen

Key Findings

- RH cannot currently be produced in Australia at a price near $2/kg. It could be commercially competitive versus domestic SMR hydrogen if RHF CAPEX and/or OPEX costs drop significantly, or if the costs to produce hydrogen from SMR increase significantly (e.g. by incorporating carbon capture and storage, or by placing a price on carbon emissions, or if the price of natural gas is higher than 2020 levels).
- The renewable hydrogen industry in Australia is still in its infancy with supply chains and technical expertise still being developed.
- Government funding or other assistance will be required to make the RHF project commercially viable if renewable hydrogen is to compete directly with 'grey' hydrogen produced by SMR.

Key Lessons

- RH is not yet competitive with the cost to produce 'grey' hydrogen. If carbon emissions from SMR are not taken into consideration, it is unlikely RH will be able to compete over the medium term, even with forecast cost reductions.
- An export market for RH from Australia requires, as a precondition, the establishment and successful operation of local hydrogen production capabilities. Ammonia, methanol, and refined fuel are the major local applications for hydrogen. Unfortunately, industrial customers for these products are not currently willing to pay a premium for products made using RH.

18.1.2 CAPEX and OPEX costs

Key Findings

- The CAPEX and OPEX costs for the RHF are higher than originally speculated at the beginning of the feasibility study.
- Cost-effective solutions for large scale electrolysis and hydrogen storage need to be found for renewable hydrogen to be produced at more competitive prices.
- The relative proportions of CAPEX costs for the RHF project are:
  - Solar farm approx. 33%
  - Electrolyser trains approx. 33%
  - Storage and pipelines approx. 15%
  - Other costs approx. 15%
- Over 50% of OPEX costs over the 25-year life of the RHF were attributable to the solar farm alone, and personnel costs were approximately 15% over the same timeframe.

	- The challenges and opportunities in implementing large-scale RH production are not resolved by implementing multiple small-scale facilities. Economies of scale through infrastructure integration (whether BOS or BOP) will not be developed for small-scale facilities (<5MW). As a consequence, small scale facilities do not de-risk the engineering and/or improve the 'bankability' of scale-up.
Key Lessons	- Vendors and suppliers should be engaged as early as possible for them to fully understand the project requirements before submitting budget pricing for equipment and spare parts. - The value engineering process that was carried out during the feasibility stage should continue during the FEED stage of the project with the aim of significantly reducing CAPEX and life cycle costs, especially with regards to the generation of DC power as well as the production and storage of hydrogen. - For more accurate project costing and to better extract efficiencies from the design, it is prudent to balance worst case vs best case scenarios. The worst case is derived by employing existing engineering methodologies and some incremental improvements. The best case arises from engineering step change. An example of a step change is increasing the number of electrolyser stacks per module, which has been found to reduce cost over traditional configurations. - Manufacturers of electrolysis equipment will need to scale-up production significantly for prices to fall to levels that will assist RH to compete with SMR.

18.1.3 Project timeline

Key Findings	- The overall project duration was estimated to be approximately four years which includes the FEED stage, Concept Studies, Permits/Approvals, EPC, and Commissioning.
Key Lessons	- OEM vendors, regulatory bodies and EPC companies should be engaged to understand the various options to reduce, compress or accelerate the respective project delivery periods.

17.2. Technical Feasibility

18.2.1 RHF Modelling and Design Configuration

Key Findings	- In order to arrive at the 'final' design an iterative design process was undertaken where several models were developed and alternative design configurations for the RHF were identified and assessed, each with different sizing for the solar farm, the electrolysers and for hydrogen storage. The models combined

	multiple variables within each of the main RHF components (i.e. capacity, efficiency, losses, variability, etc.) to arrive at an optimal design outcome relative to the key design criteria constraints. - No single organisation or company was identified in Australia with the complete in-house capabilities to model and design a large-scale renewable hydrogen production and storage facility. Consequently, various specialist consultants both from Australia and internationally had to be engaged to work independently on respective aspects of the project (e.g. solar farm, DC and AC power systems, storage, etc.). - A dedicated RHF requires optimal renewable supply. Therefore, before concept planning can start a comprehensive knowledge of site specific available renewable energy is required. For example, the high solar irradiance at the Moranbah site allows for a high solar utilisation (23-30%) compared to wind in this region. - There is still potential to further refine and optimise the design during the FEED stage in order to reduce CAPEX/OPEX and to streamline the operations and maintenance of the facility.
Key Lessons	- Due to a lack of large-scale renewable hydrogen production facilities in Australia or globally that could be used as a case study, it was necessary to develop a unique design configuration for the feasibility phase of the project. - Modelling and designing a cost-effective renewable hydrogen production and storage facility is a complex process when faced with an intermittent solar power supply, especially with the supply of hydrogen required at the offtake point having to be maintained at a relatively constant flowrate on a 24/7 basis. This complex modelling required detailed analysis using historical data, with careful consideration of the effect of seasonality. - The differences between peak, average and worst years are significant and will result in variable operating performance. Selecting the 'right' baseline is difficult and to a large extent depends on the assumptions used. - Choosing a P80 or P90 outcome (i.e. 80 or 90% certain that the design production will be achieved every year) will significantly increase upfront capital expenditure and will generate significant 'unused' hydrogen in most years unless there are additional users or the ability to substitute alternative supplies. Choosing lower likelihood outcomes increases the risk that the RHF has lower revenue than modelled, potentially jeopardising the business case (especially if it occurs in the early years of operation). This type of risk will require financiers (whether private or government, debt or equity) to recognise the volatility in cashflows and take a 'through cycle' view. - Finalising (i.e. freezing) the design as early as possible reduces the requirement to constantly revise multiple documents and

key engineering deliverables to keep them in sync with the changing design.

- Key consultants and vendors should be brought together to work collaboratively on the preliminary design philosophy early in the design process so that critical technical issues and constraints can be identified and resolved as quickly as possible. This 'workshopping' of the RHF technical configuration with key design stakeholders and technical experts may reduce the number of design iterations, thereby allowing the 'final' design to be developed in a faster timeframe.
- Actual meteorological data collected at the DNM site using a weather station would have been very useful rather than having to rely upon data and weather information from external sources for regional areas around Moranbah. Projects that are planned adjacent to existing facilities will benefit if the existing facilities collect detailed meteorological data over several years (ideally).

18.2.2 Equipment Selection

Key Findings

- Critical equipment for large-scale renewable hydrogen production and storage facilities (e.g. electrolysers, solar modules/trackers, DC/DC converters, batteries, compressors, and tanks) are required to be imported because very limited local manufacturing exists in Australia at present.
- When deciding which electrolyser technology to use, it is important to consider capital cost, operational cost, efficiency, hydrogen production pressure and the operating cycle requirements. Due to low operating pressures for alkaline electrolysers, there are additional operational costs associated with shutdown and start up (nitrogen purging every day) and additional compression required for storage. Published data from electrolysis equipment providers usually cannot be directly compared as there are different inclusions (in particular, compression and cooling). Preliminary design must be completed to determine lifecycle CAPEX and OPEX costs which makes it difficult and expensive to truly compare technologies.
- Designing for and sourcing suitable hydrogen compressors was challenging. Even though hydrogen compressors are available, compressors that can accommodate variable supply for the large volume, flow rates and pressures required for a large scale BTM RHF are limited.
- Integrating a DC/DC solution behind the meter to supply power to the electrolysers is more cost effective than an DC/AC/DC configuration behind the meter and a traditional grid connected AC system.
- It is more cost effective to centralise the water treatment system as opposed to treating the water at each electrolyser skid with resin bottles (originally proposed by Hydrogenics, as their system

	is based on their 2.5MW skid design). Most electrolysis providers are not currently looking at large scale (>20MW) module integration as market demand is for 1-10MW capacity, so there is no return on design investment.
Key Lessons	- Having a source of DI water to the required specification will assist to lower CAPEX by not having to install additional water treatment and purification systems. - Federal and state governments have an opportunity to facilitate the growth of a new renewable hydrogen industry in Australia where certain key equipment is manufactured locally, and technical expertise is developed by the local workforce. Regional areas around the country could then benefit from the construction and operation of large-scale RH production facilities.

18. Conclusions and Recommendations

The major technical conclusion of the study is that a BTM 160MW electrolyser facility capable of producing 8,448tpa of hydrogen, 54t of hydrogen storage to meet a nominal 23.8tpd hydrogen needs of an expanded ammonia plant is technically viable.

The optimal location of the renewable energy generation assets is co-located adjacent to the Dyno Nobel Moranbah plant. There is significant cost savings to producing the hydrogen via a DC/DC direct feed from the renewable solar plant. The cost of storage and transport of hydrogen is significant at present and further re-enforces co-location.

However, the project is only commercially viable with substantial government assistance.

The pathway for RH displacement of natural gas as a feedstock will require a dramatic reduction in renewable energy input costs (grid-connected - leveraging underutilised investment in renewables generation to secure low power prices, BTM - reduction in capital and operational costs), reduction in total installed capital cost (through equipment, installation, automation, etc.), market acceptance of price premiums for industrial products produced from renewable energy (e.g. customer demand or regulatory requirements) and increased demand for RH into high value domestic applications (e.g. transport). This makes the timeline for RH displacement of SMR hydrogen for industry highly dependent on government policy.

If projects like this and others of a similar size and nature are deployed, there could be a pathway towards commercial viability of large-scale renewable hydrogen without subsidies for future projects.

The authors note that the development of an emerging renewable hydrogen industry is occurring globally, largely sponsored by Government investment. With recent announcements of EUR 9bn[47] in Government initiatives in Germany, USD 1.8bn in South Korea, GBP 12bn in the UK[48], Australian investment (approximately AU$370M) is being dwarfed by competitor countries. Without increased Australian investment in this sector, it is likely that key development in technology and manufacturing capability will be made overseas, significantly reducing the economic development available for the domestic sector in Australia. Strong Government support for the nascent renewable hydrogen industry has the potential to create a significant number of new jobs throughout Australia, particularly in regional areas.

Based on the results of the feasibility study the authors recommend appropriate Government support be provided for this project and, more critically, the development of a renewable hydrogen sector in Australia.

[47] Germany's hydrogen ambition begins to take shape: https://www.energyvoice.com/otherenergy/248528/germanys-hydrogen-ambition-begins-to-take-shape/#:~:text=The%20German%20government's%20%E2%82%AC9bn,to%2Dgas%20technologies%20across%20Europe.&text=The%20German%20plan%20sets%20a,TWh%20of%20hydrogen%20production%20annually.

[48] 10 Countries Moving Toward a Green Hydrogen Economy: https://www.greentechmedia.com/articles/read/10-countries-moving-towards-a-green-hydrogen-economy

Appendices

1. RHF Site Layout

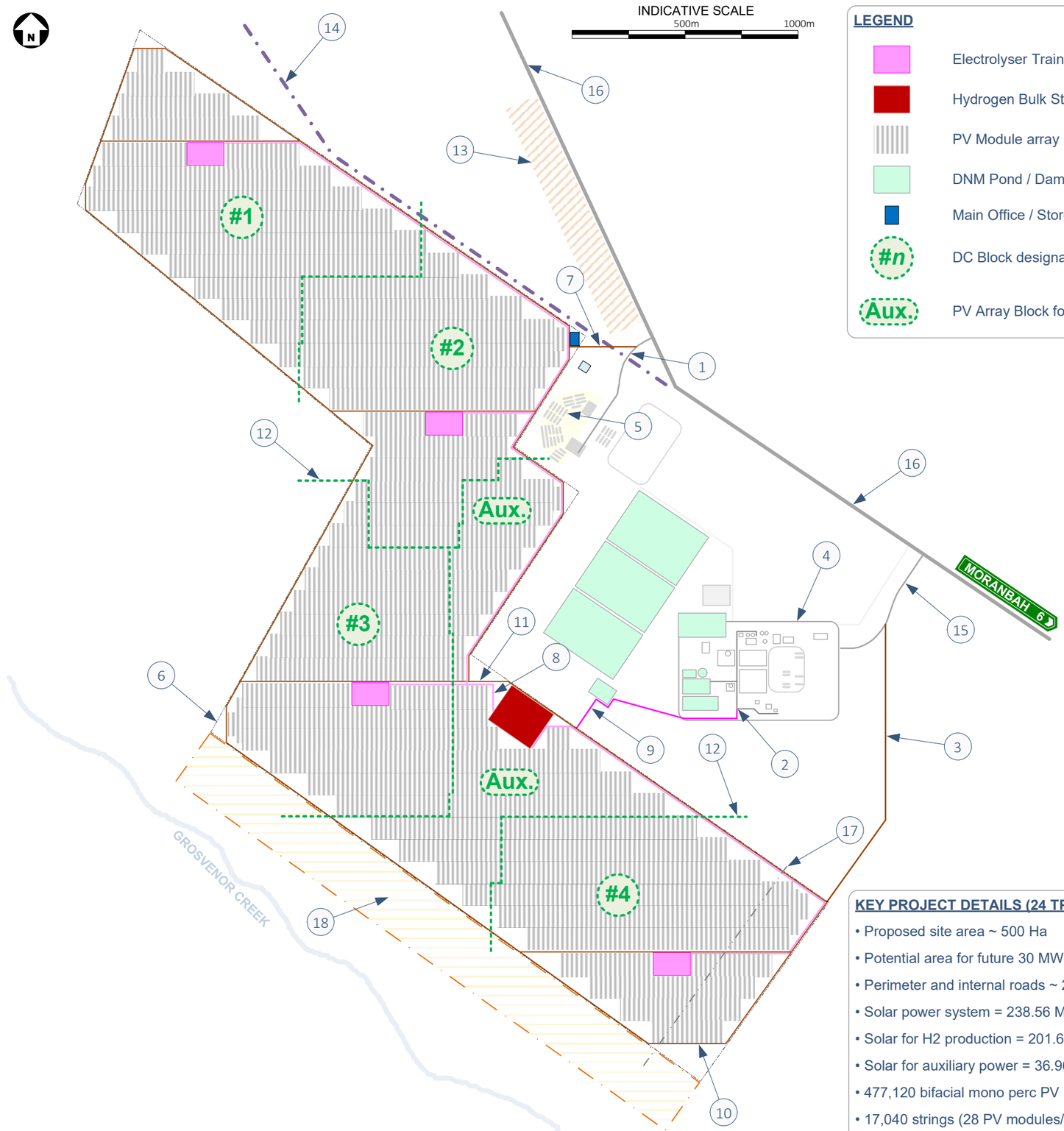
Appendix 1
RHF Site Layout

KEY

1). Existing access road to Dyno Nobel Construction Camp
2). DNM Pipe Bridge
3). Emergency Access Road for RHF
4). Dyno Nobel Moranbah Ammonium Nitrate Plant
5). Construction Camp (portacabins)
6). Perimeter fence (property boundary) enclosing area ~ 500 Ha
7). Main Access Road for RHF
8). RHF Hydrogen Pipelines (internal)
9). Hydrogen Supply Pipeline within DNM property [DNM scope]
10). RHF Perimeter Road
11). RHF Internal Roads (E-W) to Electrolysers
12). 40 MW DC Block boundary (for reference only)
13). Landowner easement
14). Easement for buried HP Natural Gas Pipeline
15). Existing access road to Dyno Nobel AN Plant
16). Goonyella Road
17). Original Boundary
18). Potential area for future 30 MWp expansion (~ 68 Ha)

SITE LOCATION

LATITUDE, LONGITUDE: -21.96802°, 147.974182°
NORTHING, EASTING: 600447.0mE, 7570219.3 mN
COORDINATE SYSTEM: UTM84-55S



LEGEND

- Electrolyser Train (Hydrogen Generation Plant)
- Hydrogen Bulk Storage Compound
- PV Module array
- DNM Pond / Dam
- Main Office / Store Compound
- #n — DC Block designation
- Aux. — PV Array Block for auxiliary AC power system

KEY PROJECT DETAILS (24 TPD HYDROGEN PRODUCTION)

- Proposed site area ~ 500 Ha
- Potential area for future 30 MWp expansion ~ 68 Ha
- Perimeter and internal roads ~ 21 km
- Solar power system = 238.56 MWp; GCR = 0.30
- Solar for H2 production = 201.6 MWp; 64 DC/DC converters
- Solar for auxiliary power = 36.96 MWp (8 x 3.57 MWac)
- 477,120 bifacial mono perc PV modules; Rating P5-500 W
- 17,040 strings (28 PV modules/string)
- 8,520 tables (2 strings/table); 1,577 trackers
- 160 MW electrolysis; 4 trains x 40 MW ea. (8 x 5 MW electrolysers)
- 54 tonnes hydrogen storage (53t @ 250 bar; 1t @ 100 bar)

Rev.	Date	Details	Document Status	Issued for	Drawn	Checked	Approved
2	14/05/20	Hydrogen transportation pipeline	PRELIMINARY	FEASIBILITY	NS	JD	AP
1	28/04/20	Larger tank farm	PRELIMINARY	REVIEW	NS	JD	AP
0	11/12/19	Initial draft	CONCEPTUAL	REVIEW	NS	JD	AP

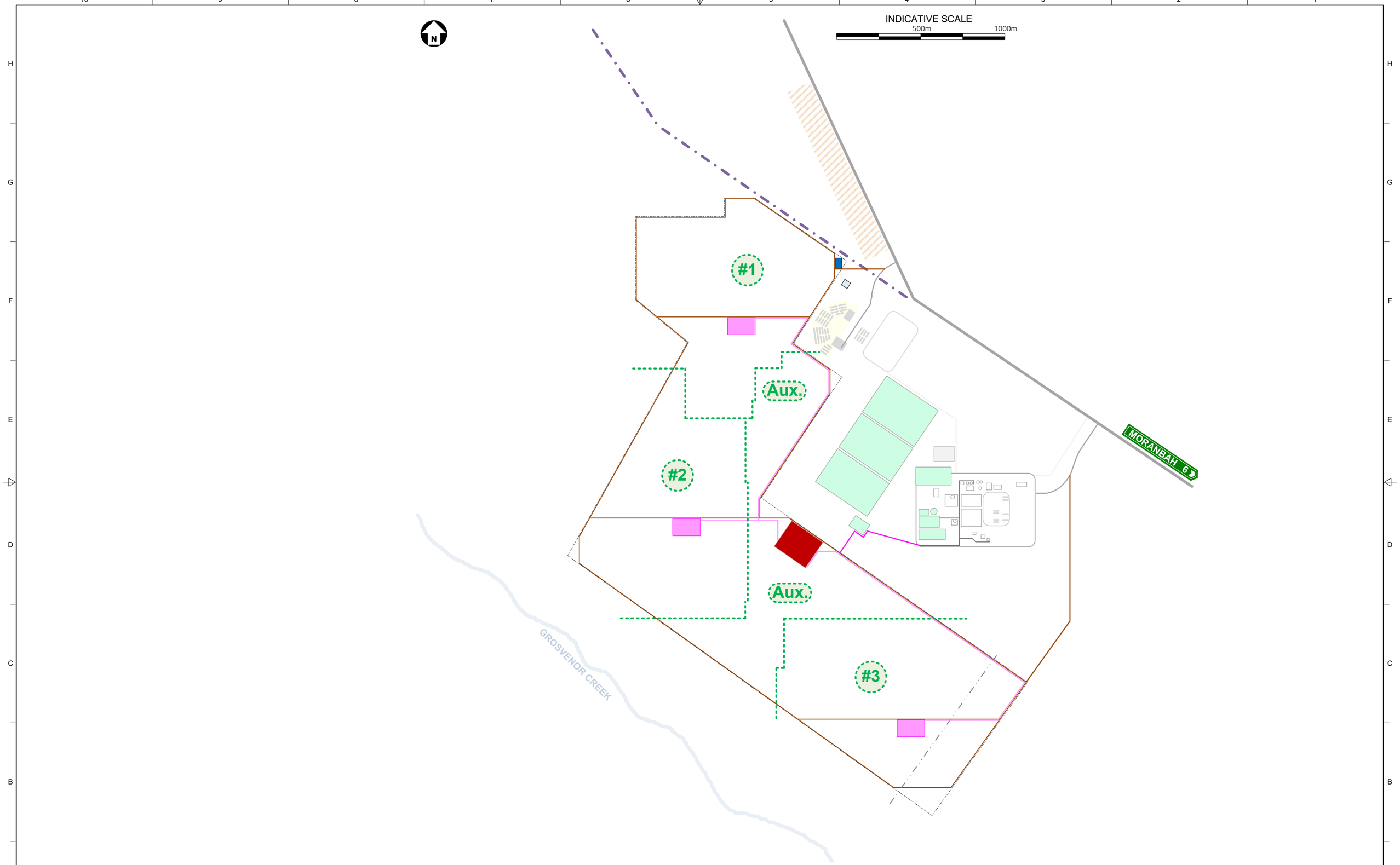
Client: DYNO Dyno Nobel

ANT ENERGY SOLUTIONS

Date: 14/05/20	Scale: NTS	Client: **Dyno Nobel Moranbah (DNM)**	Title: **Site Property Plan Layout**
Sheet: 1 of 2	Size: A3	Project: **Renewable Hydrogen Facility (RHF)**	Drg No.: 7017-8311
Part No.: - - - - -		Client Ref. No.: - - - - -	Rev. 1

File: ANTDNMPPS1008 Rev. 2 - Property Plan (RHF Site Layout)

Units in m unless otherwise specified.



Rev.	Date	Details	Document Status	Issued for	Drawn	Checked	Approved
2	14/05/20	Hydrogen transportation pipeline	PRELIMINARY	FEASIBILITY	NS	JD	AP
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0	11/12/19	Initial draft	CONCEPTUAL	REVIEW	NS	JD	AP

File: ANTDNMPPS1008 Rev. 2 - Property Plan (RHF Site Layout)

Units in m unless otherwise specified.

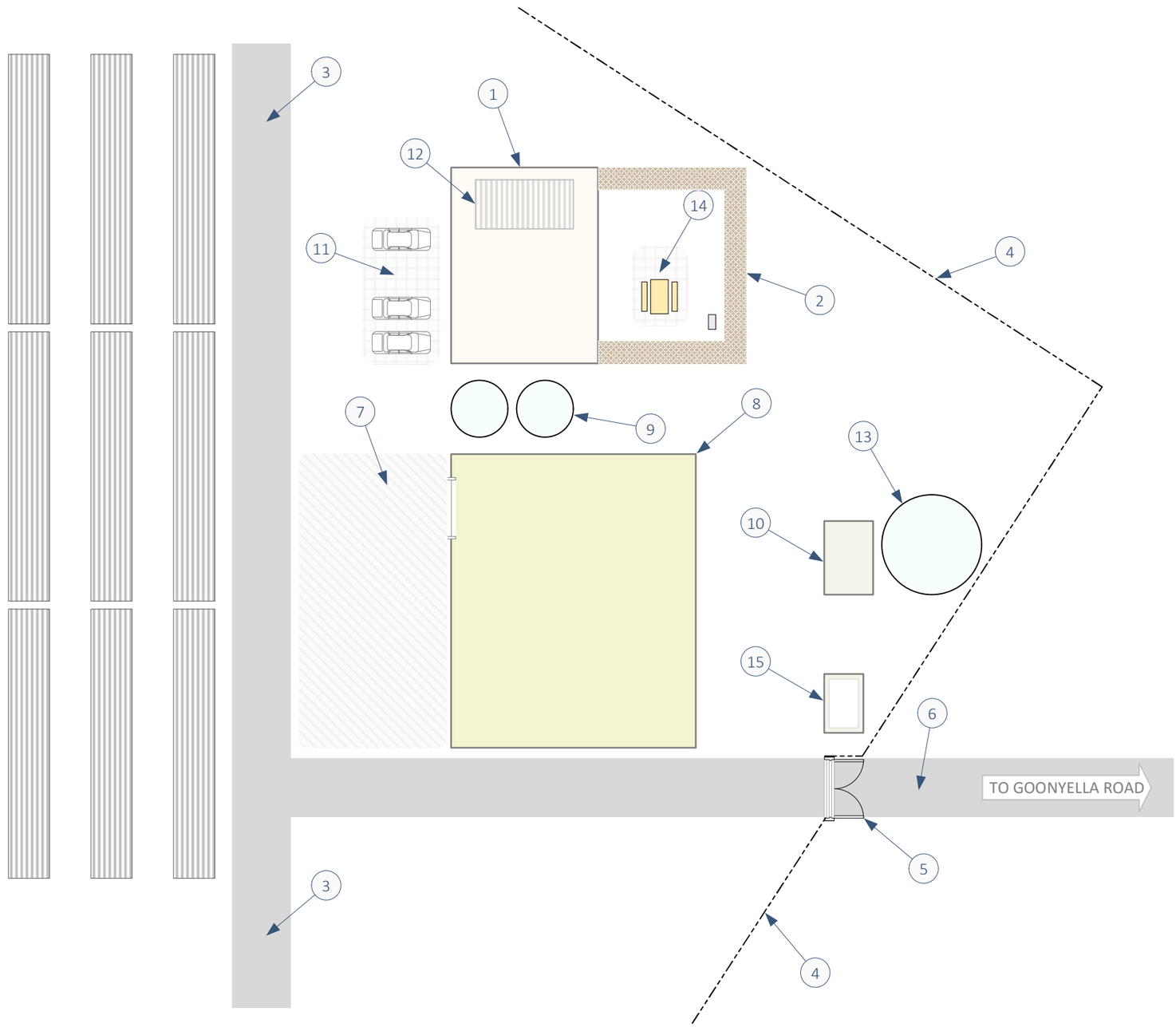
Client: DYNO Dyno Nobel

ANT ENERGY SOLUTIONS

Date: 14/05/20 | Scale: NTS | Client: **Dyno Nobel Moranbah (DNM)** | Title: **Indicative Perimeter Layout (18tpd option)**

Sheet: 2 of 2 | Size: A3 | Project: **Renewable Hydrogen Facility (RHF)** | Drg No.: 7017-8311 | Rev. 1

Part No.: - - - - - | Client Ref. No.: - - - - -



KEY

1). Office & Control Room Building
2). Landscaping
3). RHF Perimeter Road
4). RHF Perimeter Fence
5). Gate
6). Main Access Road for RHF
7). Hardstand for offloading & storage
8). Store & Workshop Building
9). Rainwater Tanks (2 off)
10). Pumphouse
11). Car Parking
12). Rooftop PV Solar Panels
13). Fire Water Tank
14). Lunch Area
15). Area for auxiliary power RMU/Transformer Kiosk and Distribution Panel

INDICATIVE SCALE
25m 50m

Rev.	Date	Details	Document Status	Issued for	Drawn	Checked	Approved
1	24/04/20	Removed fuel cell	PRELIMINARY	FEASIBILITY	NS	JD	AP
0	31/03/20	Removed metal hydride storage. Included FCPM. Single fire water tank.	PRELIMINARY	REVIEW	NS	JD	AP

Client: DYNO Dyno Nobel

ANT ENERGY SOLUTIONS

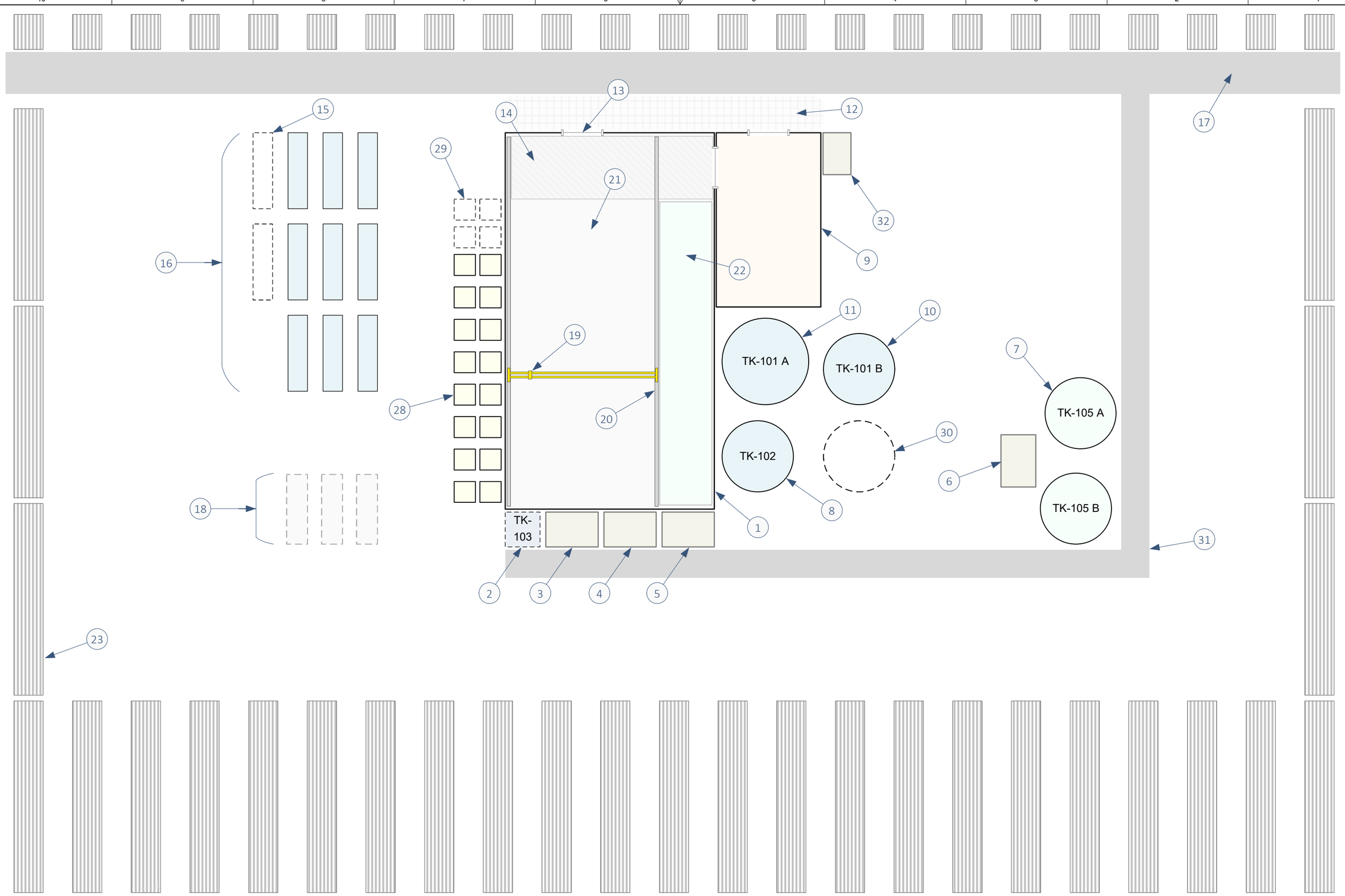
Date: 24/04/20 | Scale: NTS | Client: **Dyno Nobel Moranbah (DNM)** | Title: **Office & Store Compound Layout**

Sheet: 1 of 1 | Size: A3 | Project: **Renewable Hydrogen Facility (RHF)** | Drg No.: 7017-8371 | Rev. 1

Part No.: - - - - - | Client Ref. No.: - - - - -

File: ANTDNMDWG1066 Rev. 1 - Office-Store Layout

Units in m unless otherwise specified.



INDICATIVE SCALE

25m 50m

Rev.	Date	Details	Document Status	Issued for	Drawn	Checked	Approved
2	25/04/20	DC/DC converters	PRELIMINARY	FEASIBILITY	NS	JD	AP
1	31/03/20	Removed metal hydride storage and water treatment plant	PRELIMINARY	REVIEW	NS	JD	AP
0	11/12/19	Initial Issue	CONCEPTUAL	REVIEW	NS	JD	AP

File: ANTDNMPPS1012 Rev. 2 - Plant Layout (Electrolyser Trains)

Units in m unless otherwise specified.

Client: DYNO Dyno Nobel

ANT ENERGY SOLUTIONS

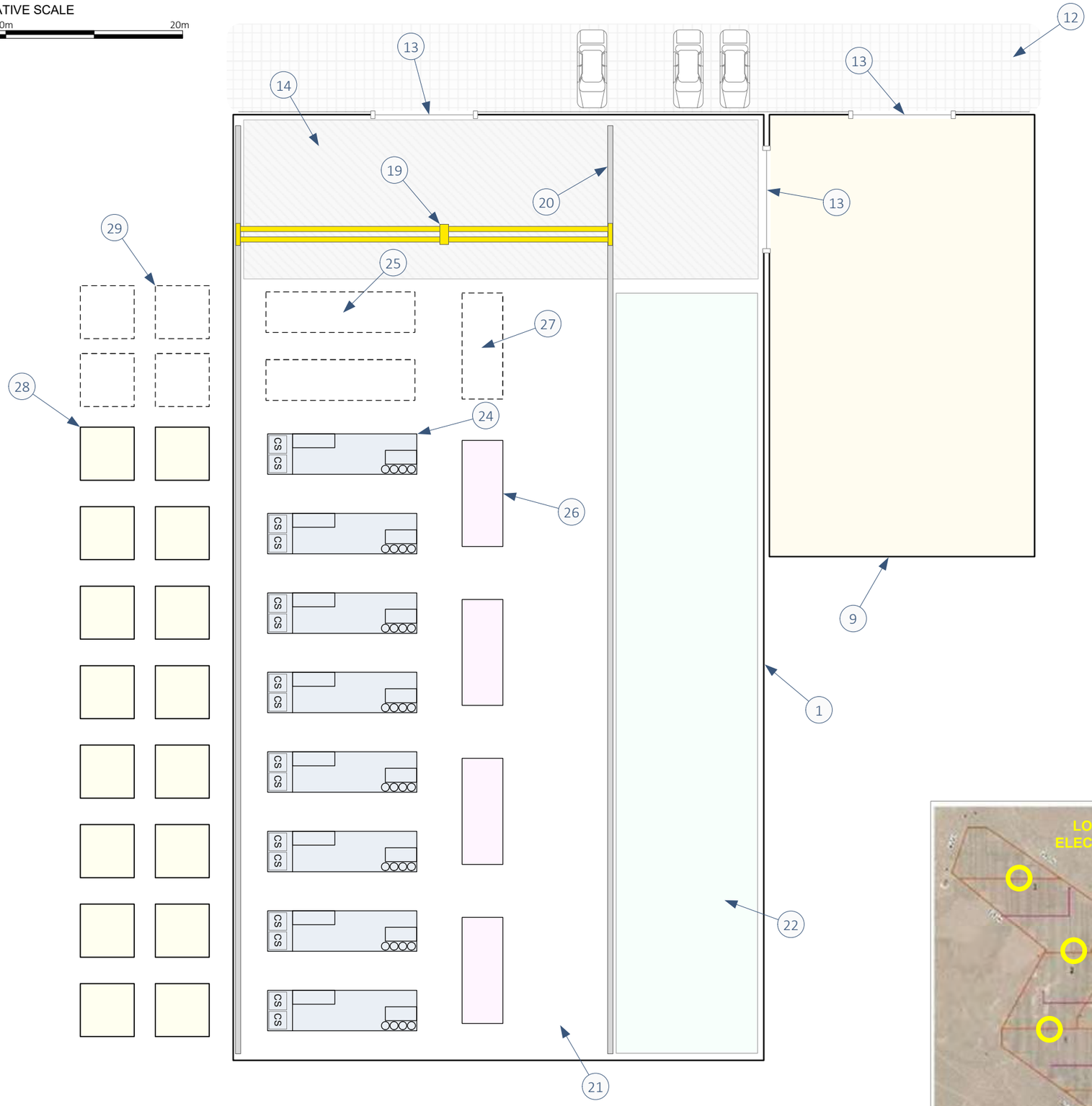
Date: 25/04/20 | Scale: NTS | Client: **Dyno Nobel Moranbah (DNM)** | Title: **Electrolyser Train - Plant Layout**

Sheet: 2 of 2 | Size: A3 | Project: **Renewable Hydrogen Facility (RHF)** | Drg No.: 7017-8321 | Rev. 2

Part No.: - - - - - | Client Ref. No.: - - - - -

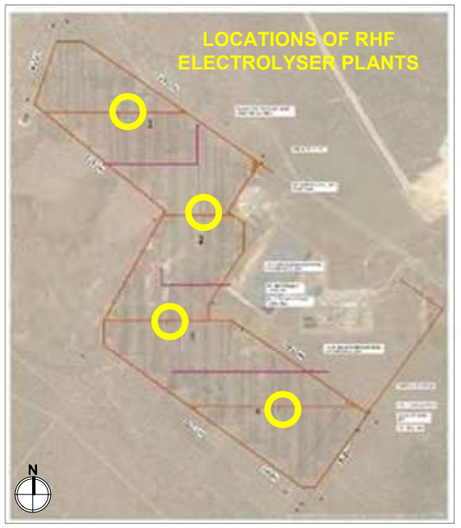
INDICATIVE SCALE

10m 20m



KEY

1). Electrolyser Train Building
2). Floor Drain Sump (TK-103)
3). Compressed (instrument) air compressor & accumulator
4). Compressed Inert Gas Storage (nitrogen)
5). Dangerous Goods Storage (span gas, etc.)
6). Fire Water Pumphouse
7). Fire Water Tanks (TK-105 A&B)
8). Utility / Rain Water Tank (TK-102)
9). Control, Storage & Electrical Building
10). DI Water Tank
11). DI Water Tank (TK-101)
12). Hardstand / Car Parking Area
13). Access door
14). Offloading / Laydown / Maintenance Area
15). Space for future dry cooler(s)
16). Dry Coolers
17). RHF Internal Road (6m wide)
18). Future O2 Dryers
19). Overhead Travelling Crane (SWL 30T, 13 m above floor)
20). Steel structure & rails for overhead travelling crane
21). Electrolyser Hall
22). Area for Aux. Supplies, Thermal Mgt, & Chillers
23). PV Solar Panels
24). HyLYZER-1000 Electrolysers (2 x 2.5 MW cell stacks each)
25). Space for future Electrolyser(s)
26). Hydrogen Dryers
27). Space for future Hydrogen Dryer(s)
28). DC/DC Converters
29). Space for future DC/DC Converter(s)
30). Space for future water storage tank
31). Service Road
32). Fuel Cell Power Module



Rev.	Date	Details	Document Status	Issued for	Drawn	Checked	Approved
2	25/04/20	DC/DC converters	PRELIMINARY	FEASIBILITY	NS	JD	AP
1	31/03/20	Removed metal hydride storage and water treatment plant	PRELIMINARY	REVIEW	NS	JD	AP
0	11/12/19	Initial Issue	CONCEPTUAL	REVIEW	NS	JD	AP

Client: DYNO Dyno Nobel

ANT ENERGY SOLUTIONS

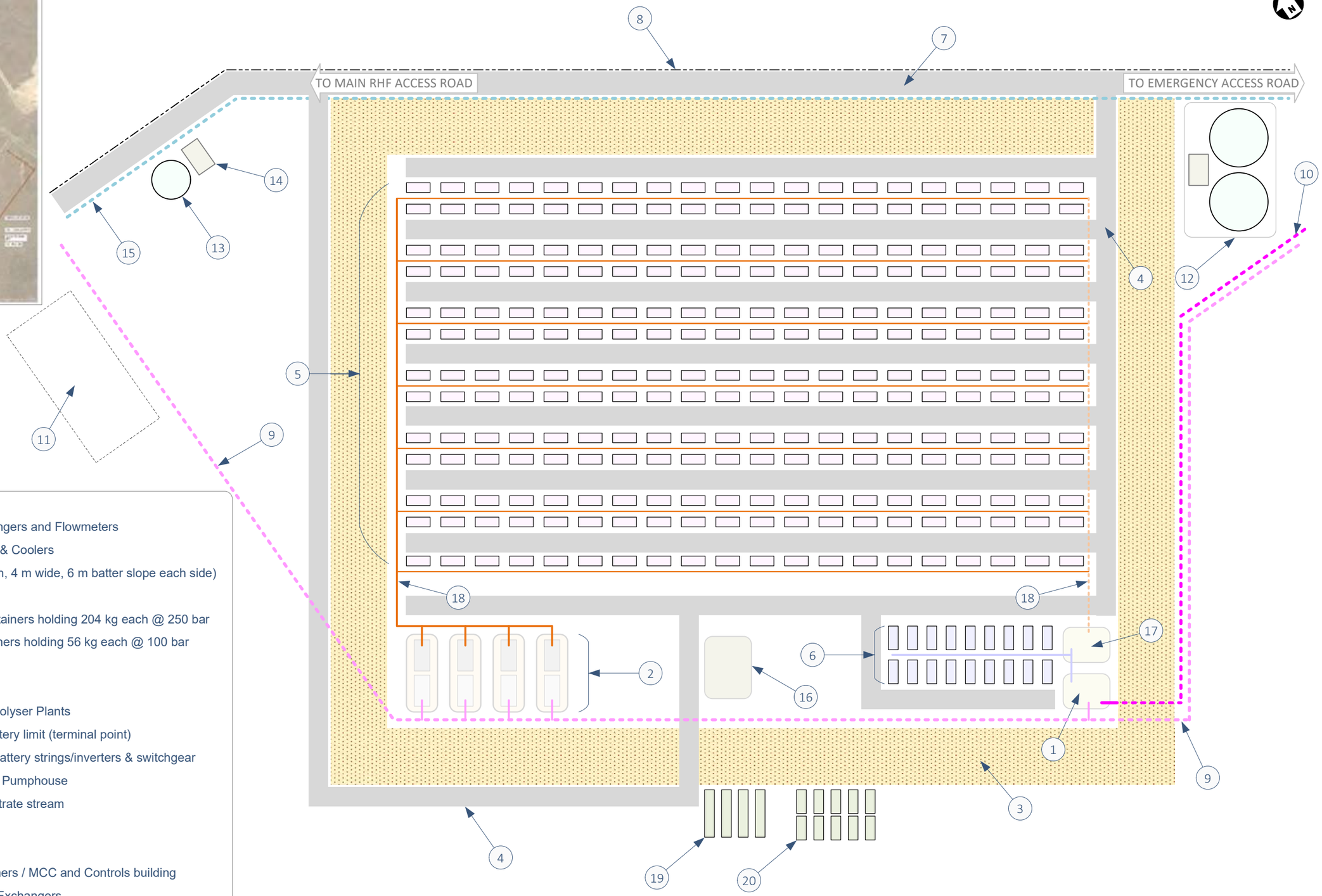
Date: 25/04/20 | Scale: NTS | Client: **Dyno Nobel Moranbah (DNM)** | Title: **Electrolyser Train - Plant Layout**

Sheet: 1 of 2 | Size: A3 | Project: **Renewable Hydrogen Facility (RHF)** | Drg No.: 7017-8321 | Rev. 2

Part No.: - - - - - | Client Ref. No.: - - - - -

File: ANTDNMPPS1012 Rev. 2 - Plant Layout (Electrolyser Trains)

Units in m unless otherwise specified.



KEY

1). Regulators (100bar/32bar), Heat Exchangers and Flowmeters
2). Hydrogen Compressors (34bar/250bar) & Coolers
3). Blast wall (mound ~726 m long, 3 m high, 4 m wide, 6 m batter slope each side)
4). Service Road (~1,950 m @ 5 m wide)
5). 53T Hydrogen Storage – 260 x 20ft containers holding 204 kg each @ 250 bar
6). 1T Hydrogen Storage – 18 x 20ft containers holding 56 kg each @ 100 bar
7). RHF Perimeter Road
8). RHF Perimeter Fence
9). Hydrogen feed pipeline from RHF Electrolyser Plants
10). Hydrogen delivery pipeline to DNM battery limit (terminal point)
11). Alternate area for aux. power system battery strings/inverters & switchgear
12). Area for Fire Water System Tanks and Pumphouse
13). Tank for CEDI water treatment concentrate stream
14). CEDI water treatment plant
15). Water pipeline
16). Area for RMU / Switchgear / Transformers / MCC and Controls building
17). Regulators (250bar/100bar) and Heat Exchangers
18). Manifold / Header @ 250 bar
19). Battery storage strings for auxiliary power system
20). Battery inverters

INDICATIVE SCALE
50m 100m

Rev.	Date	Details	Document Status	Issued for	Drawn	Checked	Approved
3	25/04/20	Battery Packs and Inverters	PRELIMINARY	FEASIBILITY	NS	JD	AP
2	31/03/20	278 storage containers (260 containers @ 250 bar, and 18 containers @ 100 bar)	PRELIMINARY	REVIEW	NS	JD	AP
1	06/03/20	Revised hydrogen storage container configuration	PRELIMINARY	REVIEW	NS	JD	AP
0	11/12/19	Initial Draft	PRELIMINARY	REVIEW	NS	JD	AP

File: ANTDNMPPS1061 Rev. 3 - H2 Storage Compound Layout

Units in m unless otherwise specified.

Client: DYNO Dyno Nobel

ANT ENERGY SOLUTIONS

Date: 25/04/20 | Scale: NTS | Client: **Dyno Nobel Moranbah (DNM)** | Title: **Bulk Hydrogen Storage Compound Layout**

Sheet: 1 of 1 | Size: A3 | Project: **Renewable Hydrogen Facility (RHF)** | Drg No.: 7017-8351 | Rev. 3

Part No.: - - - - - | Client Ref. No.: - - - - -