ATCO CLEAN ENERGY INNOVATION PARK

KNOWLEDGE SHARING REPORT

AUSTRALIA

02/02/2021

1. Acknowledgement of Grant Funding

The feasibility study (Study) received grant funding from the Western Australian Government's Renewable Hydrogen Fund, which is administered by the Department of Jobs, Tourism, Science and Innovation (the Department).

1.1 Disclaimer

The Study represents and expresses the research, information, findings, outcomes and recommendations solely of the Recipient and does not in any way represent the views, decisions, recommendations or policy of the Department.

The Department does not accept any responsibility for the Study in any matter whatsoever and does not endorse expressly or impliedly any views, information, product, process or outcome arising out of or in relation to the Study.

Table of Contents

1. EXECUTIVE SUMMARY

1.1 Feasibility Study Overview

In January 2020, ATCO Australia Pty Ltd (**ATCO**) was awarded funding from the Western Australian Renewable Hydrogen Fund (**WARHF**) to conduct a feasibility study (**Feasibility Study**) into the development of a commercial scale hydrogen production plant, the Clean Energy Innovation Park (**CEIP**).

This Public Knowledge Share Report (**Report**), outlines key findings from the Feasibility Study performed for the CEIP:

- Market scan of competing hydrogen initiatives in Western Australia (**WA**)
- Assessment of potential energy supply options to power the CEIP
- Consideration of potential regulatory approvals and licensing required
- Market sounding with industrial, mining and transport sector participants
- Ongoing commercial discussions regarding a potential joint venture delivery model for the CEIP
- Assessment of broader commercial and risk factors that may impact the CEIP including commercial and economic viability, regulatory barriers and/or uncertainty, supply and contracting terms and industry growth barriers.

1.2 Key findings

1.2.1 Market sounding

The hydrogen industry in Australia is in its infancy, with most projects at this stage supported either by State Governments or through the funding arms of the Federal Government. The market is vibrant and interest in hydrogen has grown exponentially over the past few years. State Governments in Australia and many countries offshore have set decarbonisation targets and it is expected that hydrogen will play a major role in fulfilling these commitments.

A number of hydrogen projects are currently in development in Western Australia. Noteworthy hydrogen projects include the BP Hydrogen Plant at Geraldton, aiming to produce 20,000 tonnes of renewable ammonia per year and to scale up to 1 million tonnes per year, and the Arrowsmith Hydrogen Plant near Dongara, aiming to produce 25 tonnes of hydrogen per day. These hydrogen projects could be supported by the same local offtake opportunities in the local market as ATCO.

From the market sounding it was clear that hydrogen usage is set to ramp up rapidly over the coming years. Although potential user projects are mostly in early stages, increased opportunities for partnerships on the supply side or joint offtake arrangements, may accelerate these projects achieving feasibility. Overall there appears to be little interest from potential off-takers at this stage to enter into binding agreements in the near term.

1.2.2 Corporate structure and hydrogen offtake solution

The CEIP could be delivered through various models, of which the two most plausible options are:

- ATCO delivers the CEIP, either as a corporate project (consolidated into the ATCO balance sheet) or an off-balance sheet project (SPV with ATCO as the sole sponsor); or
- ATCO delivers the CEIP in an SPV structure with multiple joint equity investors.

Both these delivery models have benefits and disadvantages. Under the first model, ATCO will fund 100% of the required equity contribution, and all operating expenses of the CEIP will be borne by ATCO. However, this model will provide flexibility to ATCO to negotiate funding agreements, hydrogen offtake agreements and other agreements in terms of partnerships for the establishment of the CEIP, as ATCO sees fit; and will provide the opportunity for ATCO to work with government and other stakeholders in the industry, in line with ATCO's own hydrogen strategy and vision.

In a joint venture model, risks and costs related to the establishment and operation of the CEIP will be shared proportionately among the equity participants, and the parties will have a consolidated voice and more bargaining power in matters relating to hydrogen in Western Australia, and funding for the CEIP. Pricing of hydrogen from the CEIP will be jointly determined by the JV partners, and may not necessarily align to any individual party's return or strategic expectations. However, joint selling of hydrogen from the CEIP at a price that is acceptable to the market, may be more likely to secure long-term offtake agreements.

Discussions to explore the potential for a joint venture structure for the CEIP has commenced. It is envisaged that the joint venture will build, own and operate the CEIP facility which will be co-located with a renewable wind farm. Under this arrangement, there is scope for the CEIP to supply a material portion of Western Australia's unaccounted for gas (**UAFG**) with 'green' hydrogen and/or a small percentage of Western Australia's natural gas distribution throughput.

If the project is established under a joint venture model with multiple equity partners, a secondary factor to consider will be the downstream hydrogen selling arrangements between the partners. Pricing of hydrogen from the project will be jointly determined by the JV partners, and may not necessarily align to any individual party's return or strategic expectations. However, a consolidated approach to a sale mechanism at a price that is acceptable to the market, may be more likely to secure long-term offtake agreements.

Two possibilities exist in this regard, i.e. equity selling, and joint selling.

In an emerging industry, selling arrangements that are less complex in terms of legal and financial considerations and physical offtake arrangements from the facility, would provide most potential for first-mover projects to succeed. In light of this, joint selling arrangements may be more appropriate for a CEIP joint venture, since it requires less complex financial disclosures in terms of over and under lift assets and liabilities, as well as less complex scheduling and physical lifting arrangements at the facility. Further, it may require fewer legal agreements to be concluded between the joint venture partners, but may require approval from the Australian Competition and Consumer Commission. Challenges of a joint selling arrangement may include alignment between partners on the term of such an arrangement, and agreement on the customers of the joint venture.

As the market develops over time, the joint venture partners may want to transition to equity selling arrangements, similar to proven practices in the oil and gas industry, taking into consideration the impact of such a change on the operations and governance of the project.

A post market sounding assessment concluded that own use of hydrogen or use in an existing business would provide the most viable short to medium term revenue stream, and will provide the revenue stability project funders will be seeking. Therefore, the most viable off-take solution for the CEIP would be injection into the local gas network. The balance of production could be made available to replace or blend with traditional fuels in the transport sector noting that ramp up of volumes in this sector is likely to take some years given the capital investment required in vehicles and refuelling infrastructure.

1.2.3 Pricing expectations

Market Sounding participants indicated that a palatable price for hydrogen would be competitive with the price of natural gas and diesel. This is a natural customer response but obviously does not recognise the broader potential benefits to their businesses associated with moving to 'green' fuels.

Market discussions also referenced recent publicly announced targets, including the Federal Government's "H2 under $2/kg" and the target set in the Australian Hydrogen Roadmap (2018) of $2.50/kg by 2025.[1] These prices are largely aspirational and geared towards exports as such, they do not form a firm comparison point for domestic hydrogen offtake.

Therefore, unless the cost of electrolysers or the renewable energy input cost materially reduces in the short to medium term, broader regulatory and industry support from the Government will be required to bridge the funding gap and meet the announced price targets.

It is important for first-mover projects to require equity returns commensurate with the size of their contributions and any Government grants received. The hydrogen industry will take years to reach commercial feasibility and in the early years private market players will have to take a strategic view on their market share in the long-term, and be prepared to make sizeable investments in the short-to medium term while the industry as a whole is not yet commercially viable. This strategic view will have to outweigh achieving financial metrics in the short-term, if players want to cement their positions in the industry.

Pricing of hydrogen produced at the CEIP will include equity returns expected by ATCO's Board, but will have to compete with other suppliers in Western Australia that may have a lower return expectation as an early participant in the hydrogen market.

1.2.4 Government support

The $70m Renewable Hydrogen Deployment Funding (**RHDF**) opened by the Australian Renewable Energy Agency (**ARENA**) will play an important role in supporting the economic viability of early stage hydrogen projects such as the CEIP.

In addition to grant funding, additional Government initiated incentives that drive hydrogen transition and/or account for the impact of carbon emissions could in some cases be the difference between hydrogen being cost-competitive with other energy options. There are various examples around Australia of such policies directly related to the renewable energy industry, where Government has enacted measures (e.g. renewable energy certificates) to continue to support the new industry.

Supportive gas blending regulation will be crucial in deriving stable revenues for the parties looking to invest into a joint venture for hydrogen production. However, significant barriers currently exist, including having regulations in place to include the CEIP in ATCO's regulatory asset base by the time CEIP operations commence and/or having blended gas included in the gas regulatory framework.

In order to facilitate hydrogen blending into the gas network, support from the Western Australia Government will be required to mandate hydrogen for gas network usage. Mechanisms such as UAFG and System Use Gas (**SUG**) could assist in kick starting the industry to create short term demand. The Western Australia Government may also provide ongoing regulatory support by mandating blending of hydrogen into the gas network at a sustainable level (aiming for a 10% hydrogen blend by 2030)[2].

[1] National Hydrogen Roadmap, CSIRO, 2018

[2] Department of Jobs, Tourism, Science and Innovation – Western Australian Renewable Hydrogen Roadmap, November 2020

2. PROJECT OVERVIEW

2.1 Context and status

Economies all over the world are increasingly considering options to move towards a low carbon future and investing heavily in net-zero strategies. Hydrogen gas has been predicted to play a significant role in these strategies, offering diverse applications as an energy carrier with great potential to support decarbonisation of the world's energy, transport and industrial sectors.

Following the announcement in January 2020 of the funding awarded from the WARHF, ATCO and the State of Western Australia subsequently proceeded to execute an agreement to study the feasibility of constructing a hydrogen production plant to supply approximately 1,200 tonnes per annum of emissions-free hydrogen in Western Australia.

The CEIP seeks to establish Western Australia's first commercial-scale green hydrogen production plant, which will integrate large scale renewable generation with hydrogen production through electrolysis. As a result, no greenhouse gasses will be emitted in this process. The plant will be based on guaranteed production from a collocated renewable electricity generation source in the mid-west region of Western Australia.

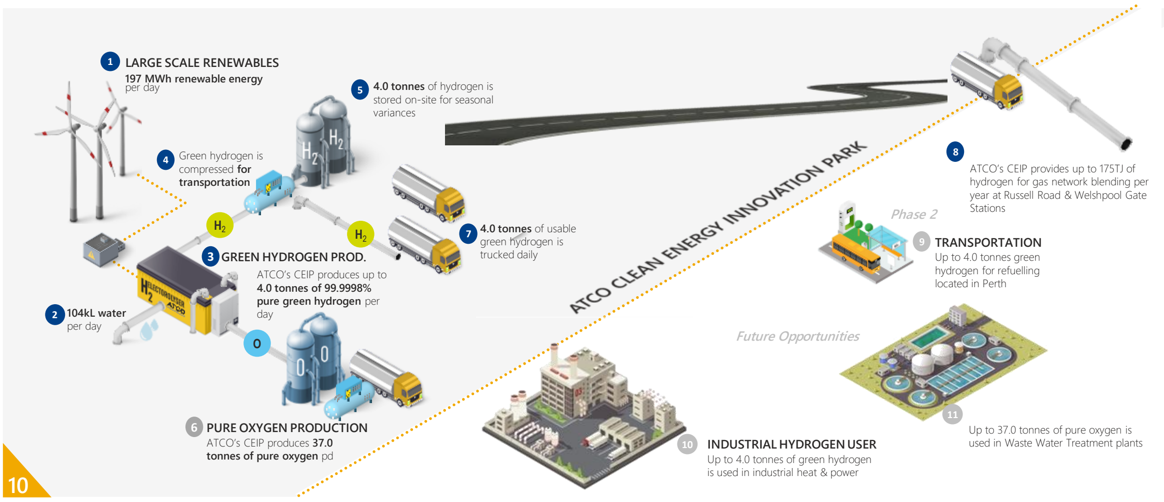
Powered by a 10MW electrolyser, the hydrogen production plant will be capable of producing up to 4.0 tonnes of useable hydrogen per day. In addition to the hydrogen production plant, the CEIP will also include:

- Hydrogen compression and storage facilities
- Future potential for Oxygen compression and storage facilities

Figure 1 below depicts the CEIP concept.

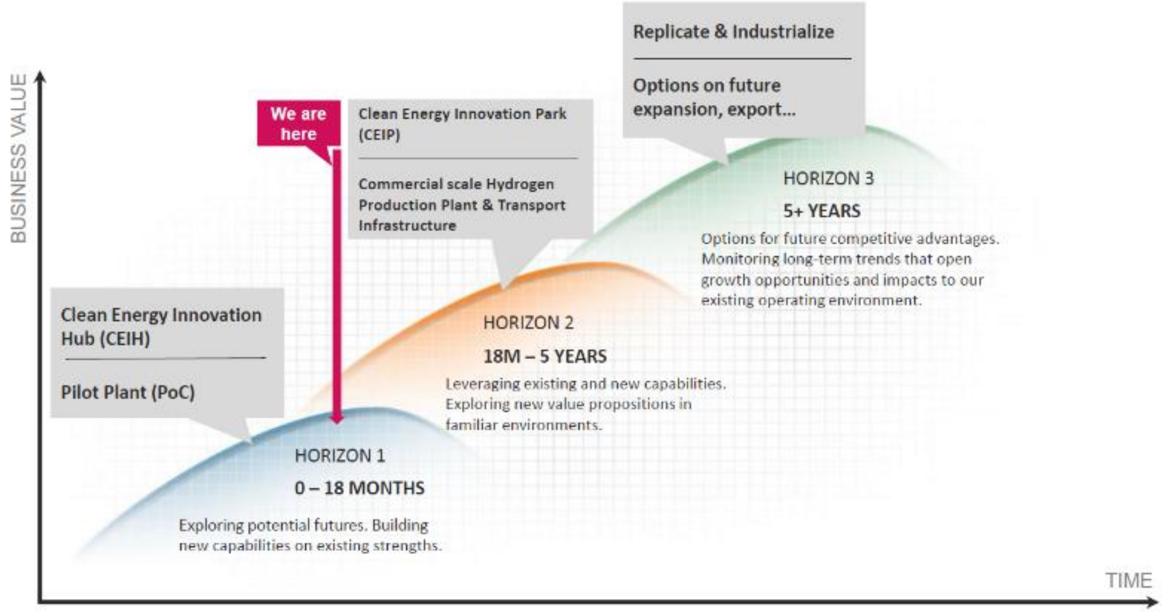
Figure 1: CEIP Hydrogen Production Facility[3]

The CEIP is expected to commence operation in 2023 in line with the time horizon plan shown in Figure 2.



[3] ATCO Clean Energy Innovation Park project plan, September 2019

Figure 2: Expected timeline[4]



2.2 Decarbonisation objectives

The CEIP aims to assist large energy users to transition into low-carbon technologies and manage their carbon foot prints, contributing to State and Federal decarbonisation targets. This, against the backdrop of Western Australia having announced an emissions reduction target in August 2019, aligned to the Federal target of 26%-28% by 2030 and zero emissions by 2050.

Western Australia currently contributes ~17% of Australia's total greenhouse gas emissions, whilst its population accounts for 10% of Australia's total population. [5]

Green hydrogen will play a significant role in the decarbonisation journey of Western Australia going forward. Over recent years, the Australian government has funded various projects in the entire hydrogen value chain to help develop the overall industry. Reports and industry leaders suggest that Western Australia's world-class renewable energy resources, established energy production and export industry, and proximity to key international markets make it well placed to produce, use and export renewable hydrogen.

WA is currently the second largest LNG exporter globally, with export capacity of more than 40 million tonnes per annum. Renewable hydrogen exports can leverage off the existing LNG industry, in terms of transferrable skills, established supply chains and expertise in building a world-class energy export industry. The WA government has set a goal to approve at least one renewable hydrogen export project by 2022, and to build up its market share in global hydrogen exports to equal the current LNG market share by 2030. [6]

[4] ATCO Clean Energy Innovation Park project plan, September 2019

[5] Australian Government, Department of the Environment and Energy website

[6] Department of Jobs, Tourism, Science and Innovation – Western Australian Renewable Hydrogen Roadmap, November 2020

3. HYDROGEN MARKET

3.1 Western Australia projects

Western Australia has many attributes that provide a strong comparative advantage in the growing global renewable hydrogen market, including world-class renewable energy resources, large unpopulated land-mass, established energy infrastructure and strong trading partnerships with Asia.

A desktop scan of publicly available information identified a number of hydrogen initiatives currently being undertaken in Western Australia. These projects are summarised in Table 1 below.

Table 1: Current hydrogen projects in Western Australia

Project	Specifications	Timeline
Name: BP Hydrogen Plant **Proponent:** BP **Location:** Geraldton, WA **Status:** Feasibility study ongoing	• Renewable hydrogen and ammonia plant, with both on-site solar and connection to the grid. • Green hydrogen via electrolysis • 20,000 tonnes of renewable ammonia p.a.	• Funding announced on 8 May 2020, study to be completed by Feb 2021 ($1.71M funding from ARENA)
Name: Arrowsmith Hydrogen Plant **Proponent:** Infinite Blue Energy **Location:** Near the town of Dongara, about 320km north of Perth **Status:** Construction go-ahead is expected in early 2021	• Wind and solar energy, with integrated large-scale battery on site • Green hydrogen via electrolysis • Aims to build a series of installations throughout regional Australia • 25 tonnes of green hydrogen per day in phase 1 and plans for phase 2 that will result in an increased level to 75 tonnes per day	• Construction starts mid-2020, operational by 2022 • $ 330 M investment secured for phase 1 construction (from China Hydrogen and consortium of international investors)
Name: Hazer Pilot Plant **Proponent:** Hazer Group **Location:** Munster, WA **Status:** Construction ongoing	• Green hydrogen via the Hazer process using Fluidised Bed Reactor plant • Pilot demonstrator for the Hazer process by converting bio-methane from sewage treatment into hydrogen and graphite • 100 tonnes of hydrogen p.a.	• Construction to be completed in December 2020 and expected operations start in January 2021 ($9.41 million funding from ARENA)
Name: Woodside Hydrogen Project **Proponent:** Woodside and Japanese consortium (JERA Inc, Marubeni Corporation and IHI Corporation) **Location:** Pilbara, WA **Status:** Feasibility study to commence	• Green hydrogen via SMR (CO2 market offsets and technical abatements planned; no CCS) • A joint study to examine the large-scale export of hydrogen as ammonia for use in decarbonising ways to optimize supply chain costs and inspect construction & operations of the facilities • Woodside will examine the transition from blue hydrogen to green hydrogen using electrolysis for export	• Feasibility study to commence in 2020, with large scale exports by 2030
Name: Murchison Renewable Hydrogen Project **Proponent:** WSP / Hydrogen Renewables Australia (HRA) **Location:** Kalbarri, WA	• Green hydrogen via electrolysis from combined solar and wind farm (up to 5,000 MW) using Silzyer electrolyser (Siemens) • Aims to provide demonstration for providing hydrogen for transport fuels,	• Stakeholder engagement process commenced in November 2019

Project	Specifications	Timeline
Status: Stakeholder engagement ongoing	expand to blend with natural gas and expand to export hydrogen	
Name: Yara Renewable Ammonia **Proponent:** Yara Fertilisers supported by ENGIE **Location:** Burrup, WA **Status:** Feasibility study to commence	• Green hydrogen via electrolysis using 50 to 60 MW electrolyser, powered by more than 100MW of solar panels • 28,000 tonnes of ammonia p.a. • Study will also look into utilisation of seawater for the electrolyser.	• ARENA announced funding of $995,000 towards the feasibility study in February 2020
Name: Asian Renewable Hub **Proponent:** CWP Energy Asia - Partnership with InterContinental Energy, Macquarie Capital and Vestas **Location:** Pilbara, WA (220km east of Port Hedland) **Status:** Investment decision awaited	• Green hydrogen production • The project comprises a series of onshore wind turbines and solar panels (9GW combined wind and solar capacity, generating 50TWh of energy p.a.) • Aims to export energy from Pilbara to Asia. Underground cables also considered as alternative/complement to hydrogen.	• Investment decision expected in 2022/23 COD expected in 2025/26
Name: City of Cockburn Study **Proponent:** City of Cockburn **Location:** Henderson Waste Recovery Park, WA; Cockburn ARC, WA - new administration building **Status:** Feasibility study ongoing	• Green hydrogen via electrolysis powered by Solar PV array (10 MW electrolyser) • The study aims to examine fuel cell cogeneration of electricity to offset peak period consumption from the grid, and heat production for the admin building, in addition to assessing engineering, design and economics to make the project viable	• Study began in January 2020 ($149,000 funding from State Government Grant)
Name: Pacific Hydro Hydrogen Production Facility **Proponent:** Pacific Hydro **Location:** Kununurra, WA **Status:** Feasibility study completed and accepted for funding	• Use of electricity from existing Ord hydro power plant (with 30MW capacity) to produce hydrogen for local use as well as for export • Green hydrogen via electrolysis	• Project became successful applicant for WA Government's Renewable Hydrogen Fund in January 2020
Name: Dampier Bunbury Pipeline **Proponent:** DBNGP (WA) Nominees Pty Ltd **Location:** Pilbara, Mid-West, Metro and Peel **Status:** Feasibility study ongoing	• Blending hydrogen into existing natural gas networks • Study includes preparing roadmap for development of regulations for hydrogen blended gas in WA	• Study to be completed in late 2020, with demonstration project. if successful, to launch in 2021 ($243,000 State Government Grant)
Name: EDL Remote Power Station Hydrogen Supply **Proponent:** Energy Developments Limited **Location:** Goldfields-Esperance and Kimberley	• Hyer Penetration - EDL Hydrogen Enabled Hybrid Renewables • Green hydrogen via electrolysis	• Study to be completed in late 2020, with demonstration project. if successful, to launch in 2021 ($243,000 State Government Grant)

Project	Specifications	Timeline
Status: Feasibility study ongoing		
Name: Murdoch University Stand-alone power systems for remote communities **Proponent:** Murdoch University **Location:** Pilbara **Status:** Feasibility study accepted	• Hybrid PV-Battery-Hydrogen System for Microgrids • Study includes development of a new modelling tool to optimise design • Green hydrogen via electrolysis • Daily AC load of 2MWh proposed for each settlement	• Study accepted on 4 March 2020

3.2 Market sounding

3.2.1 Overview

As a key part of the Feasibility Study, a market engagement process was undertaken to better understand market demand for hydrogen in Western Australia and interest to take off hydrogen from the CEIP. This involved commercial discussions with organisations with commercial operations in one or more of the following areas:

- Renewable energy development;
- Energy supply and distribution;
- Transport;
- Industrial; and
- Mining.

The market sounding was aimed at soliciting information and views from participants on the following key elements:

- Market interest, capability and capacity to collaborate on the CEIP;
- Plans to use hydrogen in the future and nature of usage;
- Status of relevant plans and envisaged timelines;
- Potential opportunities or constraints in relation to collaboration with the CEIP; and
- Possible delivery and contracting models for hydrogen produced at the CEIP.

3.2.2 Feedback

Key themes identified in the Market Sounding that are relevant to the development of a hydrogen industry in Australia (and globally) include:

- There is an increasing level of interest and activity from players across the hydrogen supply chain and potential customers focussed on assessing how hydrogen can play a role in the decarbonisation of the economy.
- More companies are establishing specific hydrogen or energy transaction teams to examine potential pathways towards meeting goals around lower emissions and social licence to operate.

- Hydrogen is being viewed as a candidate to play a key role across a number of areas including power generation, transport and industrial processes but there is scepticism about the timetable and pathway towards a sustainable cost of production.
- Potential customers are cautious about any large scale move to using hydrogen in their businesses given the investment required to renew equipment or fleets to support this transition and the lack of clarity around a range of issues including safety, licencing and in some case price regulation.
- Market participants are working through how best to approach the task of allocating risk in relation to any transition to hydrogen – for example in the heavy vehicle space large scale fleet operators are looking to truck manufacturers to bear the risk associated with developing and trialling FCV prime movers.
- There is genuine interest from many potential customers in supporting hydrogen production projects, but concerns about locking in prices for any large-scale volumes which may reflect an out-of-the-money position in the medium term, if costs of production reduce as technology improves and scale of production facilities increases.

3.2.3 Assessment

A post Market Sounding assessment concluded that a proposition to use hydrogen for injection into the local gas network will be the most viable short to medium term revenue stream, as it will provide the revenue stability project funders will be seeking.

Commercial discussions to explore the potential for a joint venture structure for the CEIP has commenced. It is envisaged that the joint venture will build, own and operate the CEIP facility which will be co-located with a renewable wind farm. Under this arrangement, there is scope for the CEIP to supply a material portion of Western Australia's UAFG with 'green' hydrogen.

In terms of blending hydrogen into the gas network, the primary challenge for this concept will be obtaining the requisite gas blending and pipeline regulatory changes underpinning the plans contemplated under the joint venture proposal.

4. FINANCIAL ASSESSMENT

4.1 Pricing considerations

A palatable starting price for hydrogen from the CEIP would have to be competitive with the price of natural gas currently supplied to end customers. The latest published production price for natural gas in Western Australia is around $4.10/GJ (Dec 2019), which is largely representative of the average price over the past two years.

For transport, potential off-takers would possibly require a hydrogen pump price on par with diesel. The current average pump price of diesel is $1.50/L.

Market discussions also referenced recent publicly announced targets, including the Federal Government's "H2 under $2/kg" and the target set in the Australian Hydrogen Roadmap (2018) of $2.50/kg by 2025.[7] These prices are largely aspirational and geared towards exports as such, they do not form a firm comparison point for domestic hydrogen offtake.

In addition to publicly communicated price targets, it is particularly clear that there is a significant price gap to bridge, both in terms of hydrogen for transport and gas blending. Therefore, unless the cost of electrolysers or renewable energy materially reduces in the short to medium term, broader regulatory and industry support from the Government will be required to bridge the price gap and meet the announced price targets.

4.2 Plant specifications

The key financial inputs and assumptions used in the financial model to assess the financial viability of the CEIP, including any potential funding requirement from ARENA, are set out below.

Item	Value (units)
Electrolyser capacity	177 kg/hour
Annual degradation	<1% p.a.
Electrolyser power demand	5.3 kWh/Nm.
Electrolyser water demand	2,952 L/hour
Asset life	20 years
Windfarm capacity	180 MW

4.3 Costs

Construction

Item	Value ($000 real 2020)
Electrolyser (max 4300KG/Day)	16,000
Balance of Plant	$28,100

[7] National Hydrogen Roadmap, CSIRO, 2018

Operations and Maintenance

Fixed costs

Item	Value ($000 real 2020)
Electrolyser annual general maintenance	~$400p.a.
Balance of Plant annual general maintenance	$600 - $800p.a.

4.4 Production Forecasts

Item	Volume (units)
Hydrogen	1,267,561 kg p.a.

5. COMMERCIAL AND RISK CONSIDERATIONS

5.1 Potential offtake contracting models

The ultimate contracting terms for offtake of hydrogen produced at the CEIP will largely be informed by factors including the type of counterparty, nature of hydrogen use, risk tolerance of parties and level of dependence on the hydrogen supply. The following key messages were obtained from Market Sounding participants with respect to potential supply and contracting terms:

- An industrial participant with existing operations in Victoria and Queensland raised the possibility of **virtual swap arrangements** between supply in Western Australia and supply on the East Coast.
- Other industrial participants also flagged the possibility of **purchase order contracts** to buy hydrogen on an ad hoc basis or **take or pay contracts** where the counterparty pays for the offtake, whether it takes the hydrogen or not.
- Downstream participants proposed **volume-based contracts** ramping up over time, aimed at ensuring stable supply over a specified term and incorporating delivery to designated refuelling sites.
- A potential gas network injection partner expressed a willingness to explore a **fixed volume and specifications contract** where hydrogen is physically delivered to an injection point in the gas network.

5.2 Regulatory considerations

5.2.1 Gas pipeline regulation

This section seeks to examine how gaseous hydrogen injection may work in the current regulatory framework for natural gas pipelines – the only method of gas transportation currently subject to economic regulation provisions.

5.2.1.1 Pipeline regulatory framework

In Western Australia, the National Gas Law (**NGL**) and National Gas Rules (**NGR**) combine to provide a framework for the regulation of gas pipeline services and the Economic Regulation Authority (**ERA**) holds the responsibility for regulating pipeline services in Western Australia.

Under the NGL and NGR, gas pipeline operators earn revenue by selling capacity to third parties needing to transport gas - termed ‘providing access’.

Access arrangements

The mid-west and south-west gas distribution pipelines operated in Western Australia are full regulation pipelines meaning it is required to submit a ‘full access arrangement’ to the regulator for ERA approval. The access arrangement submission is required to set out key elements such as the pipeline services and terms and conditions of pipeline use.

Regulated Asset Base (RAB)

Access arrangement proposals must include how the capital base is arrived at, and if the access arrangement period commences at the end of an earlier access arrangement period, it must provide a demonstration of how the capital base increased or diminished over the previous access arrangement period.

Proposal must also include the projected capital base over the access arrangement period, including:

- A forecast of conforming capital expenditure for the period and the basis for the forecast; and
- A forecast of depreciation for the period, including a demonstration of how the forecast is derived based on the proposed depreciation method.

UAFG

Access arrangement proposals are also required to provide a forecast of operating expenditure, of which a key component is the cost of UAFG.

UAFG refers to gas supplied into the gas distribution system that is unaccounted for in delivery from the system. It forms the difference between the measurement of the quantity of gas delivered into the gas distribution system in each period and the measurement of the quantity of gas delivered from the gas distribution system during that period. The difference is effectively 'lost' and the UAFG that has not been delivered to customers will need to be replaced. This opens up an opportunity for the use of hydrogen to replace UAFG quantities.

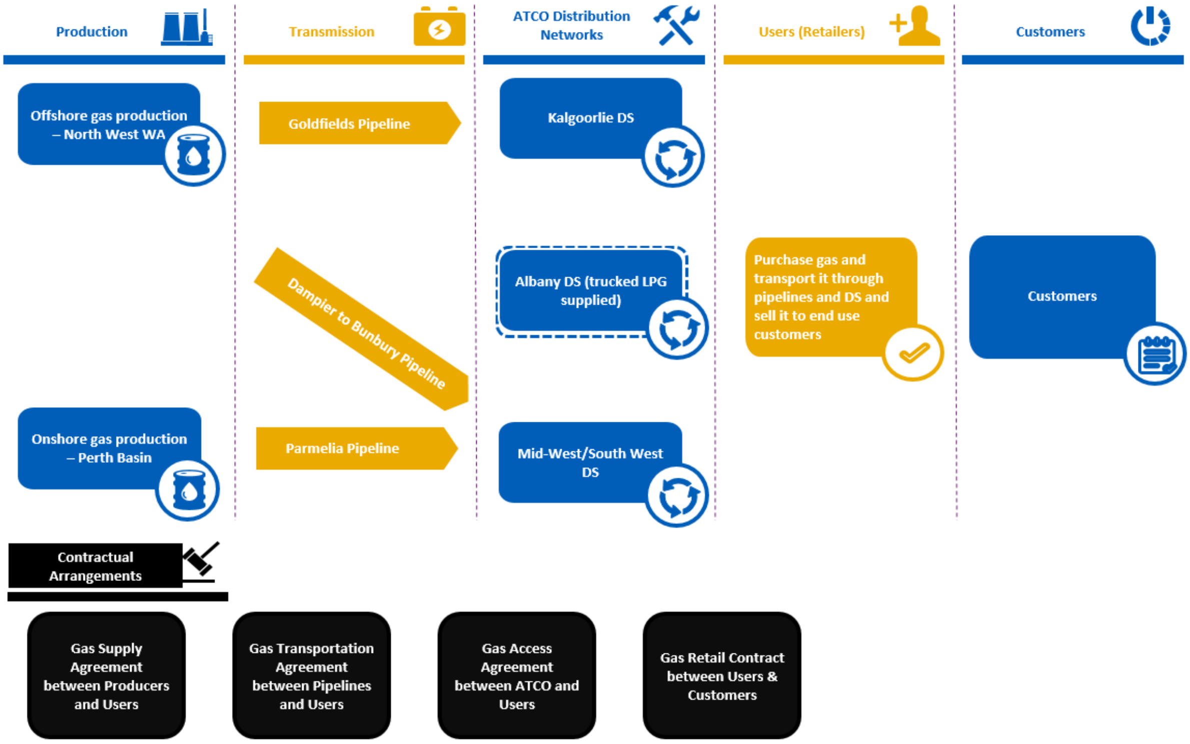
Tariff determination

The outcome of the regulatory decision-making process is an approved full access arrangement that amongst other items, specifies the regulated prices (reference tariffs) for providing access services and the non-price terms and conditions for those services. While a potential user may wish to contract for a specified reference service, it may also negotiate for another service from the pipeline operator.

5.2.1.2 Regulated vs unregulated pipeline

Figure illustrates the current commercial setup of the Western Australia natural gas market, including the key participants and the contractual arrangements that exist between them.

Figure 4: Current Western Australia natural gas market



In the context of the current Western Australia natural gas market, we have examined two potential scenarios for a gas network injection solution for hydrogen produced at the CEIP.

(a) Unregulated environment – hydrogen supply as a competitive source of gas (Scenario 1)

Under this scenario:

- The CEIP facility costs are not part of the RAB and ATCO would take on complete commercial price risk;
- As a regulated full access distribution pipeline operator, ATCO would need to seek ERA approval for any cost impact to distribution system to cope with hydrogen injection; and
- ATCO would be free to set and negotiate price of hydrogen with end users.

(b) Regulated environment – hydrogen supply as a regulated distribution service (Scenario 2)

Under this scenario:

- The CEIP facility costs and distribution pipeline system would form part of the RAB, costs associated with producing hydrogen would form part of forecast operating expenditure and ATCO would be able to recover these costs from customers and make a steady regulated return;
- Regulated tariffs would be subject to a price review by ERA every five years of operation as a part of the access arrangement scheme;
- Distribution pipeline users would be required to take a Government mandated level of blended gas and may need to be compensated for any take or pay impacts on their existing gas supply agreements; and
- The price of hydrogen pipeline services would need to be formally regulated by ERA.

5.2.2 Gas blending regulation

Similar to gas pipeline regulation, a gas network injection solution will also require greater regulatory certainty with respect to:

- Whether the definition of natural gas in the National Gas Law captures blended gas;
- The extent to which the existing regulatory framework applies to blended gas; and
- The implications of this for blending activities.

Agreement is also needed on how to determine and set safe upper limits for the injection of hydrogen into gas networks and end user and market effects.

Although the future blending regulatory landscape remains largely unknown at this stage, it is reasonably expected that proponents such as ATCO would be at a minimum required to satisfy regulators that:

- The distribution network is comprised of materials confirmed to be safe and suitable for hydrogen blending;
- The distributor has adequate safety and training procedures in place; and
- The effects of blending for gas network users who currently use natural gas as chemical feedstock have been considered and mitigated.

In order to better understand these requirements, ATCO is considering partnering with identified interested parties to undertake a more in-depth technical assessment of hydrogen injection into the gas distribution system and demonstrate the feasibility of this concept to regulators.

5.2.3 Implications for the CEIP

There may be potential regulatory challenges with respect to the gas network injection proposition and a need for regulatory and broader Government support, to ensure policy and regulations are in place once blending of hydrogen into the local gas network is proven feasible.

Whilst the analysis of hydrogen in a natural gas pipeline context is a useful starting point, there are still many questions on how the regulatory framework would need to adapt to accommodate hydrogen.

The answers to these questions would initially be provided by regulators and policymakers on a case by case basis until the frameworks are updated to consider hydrogen more comprehensively. Ultimately, Governments need to play a larger role in ensuring the regulatory environment is consistent and predictable enough to support the hydrogen industry and provide desired certainty to key future players.

ATCO will continue to engage with the Government to facilitate reviews of existing legislation, regulations and legal frameworks, noting a particular focus on the following:

- Including pipeline hauling renewable gases into the NGL;
- Allowing green hydrogen production facilities to be included in the RAB for pipeline operators; and
- Instituting mandates for green hydrogen blending into the gas networks – for both UAFG and SUG.

As noted previously in this Report, regulatory support of this nature is crucial to underwriting the commercial viability of the CEIP.

5.3 Growth barriers

5.3.1 Price gap between traditional and alternative green fuels

The resounding feedback from Market Sounding participants was that the price parity of hydrogen compared with traditional fuels (e.g. natural gas, diesel) is a crucial factor for commercial deployment.

There are a number of broad market factors already in play contributing to a projected decline in the future 'green' hydrogen price. For example:

- Research and development activities are expected to lead to improvements in plant design and drive efficiencies;
- General decline in renewable energy and electrolyser prices; and
- Gradual increase in 'green' hydrogen utilisation.

Despite these forces applying downward pressure on prices, increases in production economies of scale (discussed below) are likely to truly 'turn the dial' in terms of price competitiveness. While interest in hydrogen has been steadily rising, it has not led to the required investments along the value chain. This is likely to be best addressed by Government policy and regulatory frameworks that accounts for carbon risk and explicitly seeks to meet the 'economic gap' that must be bridged in order to reach the scale at which hydrogen is competitive – potentially by way of greater industry subsidisation or energy innovation incentives.

5.3.2 Scaling of green hydrogen

Increasing the size or capacity (i.e. electrolyser use) of hydrogen projects will generally allow for reductions in capital and operating costs and improved system efficiencies. For a production project such as the CEIP, this can be achieved by securing larger or multiple offtake agreements for the hydrogen produced and in doing so, enhance scope for upsizing and positioning close to as many different points of use as possible.

Beyond the obvious issue of adding to funding requirements, scaling up production can be impacted by difficulties in meeting large land requirements to accommodate both large renewable energy developments to power the facility, and supporting production facilities. Whilst technology continues to develop, increasing scale of production can also impact upon electrolyser efficiency.

5.4 Energy supply

A key part of deploying a green hydrogen production facility involves obtaining a reliable supply of energy underpinned by renewable sources. A high-level assessment of potential 'green' energy supply contract options is discussed below.

Description / Configuration	Procurement and commercial considerations	Cost exposure considerations
Standard retail contract (grid intensity)	• **Less Favourable:** Retail contracts will likely constrain ability to optimise on a short-term basis. • **Favourable:** Can be structured to allow a reasonable degree of commercial flexibility. For example, term, volume and price can all be structured to provide some commercial optimisation. • **Neutral:** Need to consider the merits and risks of 'progressive energy purchasing', i.e. buying parts of overall demand with staggered contracts, vs. recontracting the entire load at the time of previous contract expiry.	• **Neutral:** Retailers will not pass through on the wholesale price but rather, a pre-agreed price. • **Neutral:** Network costs are regulated charges and will be passed through by the retailer to the customer. • **Favourable:** Retailer controls the price risk through their own hedge book. • **Less Favourable:** Retail costs and margin are likely to be imposed.
Physical / Direct PPA (grid connected)	• **Neutral**: New projects tend to seek longer term offtake contracts as this enables them to secure stronger financing terms for the project. An existing project may be able to offer a shorter-term offtake agreement. • **Less Favourable:** From a bankability perspective, the identity and creditworthiness of the project proponent will be a key consideration for the PPA supplier. • **Less Favourable:** PPAs require meaningful procurement effort and risk. Where long term PPAs are contemplated, this involves "acquisition like" due diligence on the underlying project. • **Neutral:** PPAs of any significant term or volume can reduce commercial flexibility by requiring the off-taker to pay for electricity via a cash settlement irrespective of underlying demand, but also offers greater stability and certainty.	• **Favourable**: Cost savings can be achieved from lack of intermediary parties involved. • **Neutral**: Network costs are regulated charges and will be passed through by PPA supplier to the off-taker. • **Less Favourable:** If capacity factor poses an issue, a hedging product will be needed to ensure a consistent supply of energy. • **Favourable**: The renewable energy market in Australia is highly competitive – falling costs of renewable energy technologies and intense competition between developers seeking PPAs are putting downward pressure on PPA prices.

Synthetic PPA + grid firming	• **Neutral:** Although price hedging benefits are available, this option includes increased exposure to the wholesale electricity market risk. • **Neutral:** Requires assessment of the net present value of the proposed PPA settlements under different electricity price scenarios and due consideration of accounting implications. • **Neutral:** The off-taker needs to weigh the potential benefits against the additional administrative costs and risks. Contracts for Difference (**CfD**s) require customers to adopt derivative accounting standards and may involve additional administrative requirements.	• **Less Favourable:** Increases exposure to wholesale electricity market risk (as spot price outcomes determine CfD settlements). • **Neutral**: Network costs are regulated charges and will be passed through by the retailer to off-taker. • **Favourable**: Retail costs may be reduced via synthetic PPAs. • **Less Favourable:** The end user will retain control for price risk
Sleeved PPA + grid firming)	• **Less Favourable:** Requires involvement of a retailer, which complicates contractual structure and increases cost to energy user. • **Favourable**: Enables multiple energy users with relatively modest energy requirements to contract for electricity with a relatively large renewable energy project – in this case, the retailer acts as a load aggregator contracting with multiple energy users. • **Favourable**: Bypasses many of the skill, transaction, risk and legal cost barriers of constructing agreements directly with project developers.	• **Neutral**: Partnering with other parties carries the added complexity of managing a group of stakeholders, relationships, multiple sets of expectations, internal approval processes and group communications, but can also bring cost sharing opportunities. • **Neutral:** Network costs are regulated charges and will be passed through by the retailer to the off-taker. • **Less Favourable:** Retail costs may be higher for sleeved PPAs. • **Favourable**: The retailer will control the price risk (through the sleeved PPAs).
BTM PPA + grid firming	• **Neutral:** Although this structure offers price predictability and dedicated supply, this option should be evaluated against the risk of paying a higher rate than the market rate should retail prices decline in the future. • **Less Favourable:** If the provider is not likely to be able to guarantee electricity output, the added contractual complexities and commercial burdens of grid connection remain. • **Favourable**: As the asset is fully owned by the provider, there is no upfront capital cost.	• **Neutral**: Network costs are regulated charges and will be passed through by the retailer to the off-taker. • **Less Favourable:** Retail costs and margin are likely to be imposed. • **Neutral**: Although network costs remain, greater proximity of co-location can give result in savings in transmission charges. • **Less Favourable:** Contractual agreements may impose O&M phase costs.

BTM PPA + battery PPA (retail style contract)	• **Less Favourable:** Where battery assets are not contemplated to be included onsite, the provider may seek some investment outlay from the off-taker. • **Neutral:** Although this structure offers price predictability and dedicated supply, this option should be evaluated against the risk of overpayment i.e. paying a higher rate than the market rate should retail prices decline in the future. • **Favourable**: As the wind farm asset is fully owned by the provider, there is no upfront capital cost.	• **Favourable**: Hybrid solutions combining renewables and battery storage can deliver significant savings on electricity supply costs, as compared to meeting the entire demand with gas/diesel fired generation. • **Favourable**: As this option completely bypasses the grid, there are likely to be lower network costs. • **Favourable**: Can enable energy users to achieve significant cost savings on the wholesale energy costs, as well as distribution and transmission charges. Typically, distribution network connected customers achieve highest cost savings from on-site generation. • **Less Favourable:** Contractual agreements may impose O&M phase costs.

6. REGULATORY APPROVALS

6.1 Applicable regulations and licensing requirements

Based on desktop research conducted on Western Australian Government department websites and consultations arranged with representatives from both the Department of Planning, Lands and Heritage (**DPLH**) and Department of Water and Environmental Regulation (**DWER**), the potential regulatory approvals that may be required for the CEIP. Table 2 summarises these findings.

Table 2: Potential regulatory and legislative procedures

Category	Elements	Requirements	Applications	Department/ Authority
Environmental Impact Assessment (EIA)	• Emissions and discharge (air, land, water) • Sea: Benthic Communities and Habitats; Coastal Processes; Marine Environmental Quality; Marine Fauna • Land: Flora and Vegetation; Landforms; Subterranean Fauna; Terrestrial Fauna • Water Inland Waters • Air Air Quality; Greenhouse Gas Emissions • People Social Surroundings; Human Health	• Documents and studies to support the elements of the EIA under the principles: Conservation of biological diversity; Intergenerational equity; Improved valuation, pricing and incentive mechanisms; Waste minimisation	• EPA report with recommendations	• Environmental Protection Authority (EPA WA)
Water and Environment	• Emissions and discharge (air, land, water) • Prescribed premises • Transportation of controlled waste on roads • Noise • Clearing of native vegetation	• Environmental surveys and the preparation of management plans to minimise the environmental impacts of the development • Licensing of carriers, drivers, and vehicles involved in	• Works approval to construct prescribed premises • License to operate prescribed premises • Licence relevant to the type of controlled waste transported	• Department of Water and Environmental Regulation (DWER) • Environmental Protection Authority (EPA WA)

Category	Elements	Requirements	Applications	Department/ Authority
	• Fauna and Flora • Sensitive species • Groundwater • Surface water • Contaminated sites	transporting controlled waste on roads • Development of relevant management plans • Management of public drinking water source areas	• Water licenses and permits • Native vegetation clearing permits • Environment Plans • Fauna and Flora Protection Plan • Biodiversity Plan • Ground Water Management Plan • Surface Water Management Plan • Water source protection plans	
Land	• Land development / use planning • Crown Land • Heritage	• Licence to use, purchase or lease Crown land and associated roads, reserves and easements • Heritage consultation • Local community engagement	• Crown land access license / lease • Development / Land Use Application • Heritage access authorisations and Conservation Management Plan • Petroleum, geothermal and mining clearing and zoning permits	• Department of Planning, Lands and Heritage (DPLH) • Western Australia Planning Commission (WAPC) • Development Assessment Panel (DAP) • Local Government • Heritage Council • Department of Mines, Industry Regulation and Safety (DMIRS)
Native title	• Community and social activities • Particular Traditional Significance • Land or Waters	• Conduct Aboriginal heritage survey • Landowner and Native Title Holder Engagement	• Consent from Native Title Holders to grant relevant licenses and permits • Indigenous Land Use Agreements (ILUAs)	• Department of Aboriginal Affairs (DAA) • Department of Planning, Lands and Heritage (DPLH) • Land Approvals and Native Title Unit (LANTU) within the Department of Premier and Cabinet (DPC) • Registrar of Aboriginal Sites • Department of Mines, Industry

Category	Elements	Requirements	Applications	Department/ Authority
				Regulation and Safety (DMIRS)
Major Hazard Facility	• Major Hazard Facility • Fire safety • OH&S	• Safety and environmental management • Fire safety management • General occupational health and safety management	• Dangerous Goods License • Registration of facility • Emergency Management Plan • Fire management plan • Manufacturing license/ Production license • Storage license	• Department of Mines, Industry Regulation and Safety (DMIRS) • Safe Work Australia

6.2 Major Project Assistance

A project of the CEIP's size, scale and scope can be reasonably expected to qualify for Major Project Assistance from the Department of Jobs, Tourism, Science and Innovation (**JTSI**).

JTSI can provide information on statutory requirements and manage and coordinate approvals applications across Government. It can also assist with identifying the potential impacts of the proposal on matters including infrastructure, the environment and regional communities, and give advice on any social considerations that may arise.

JTSI will then nominate a project manager from an appropriate Government department (a Lead Agency), who is responsible for working with the project proponent on early stage scoping work and establishing agreed timelines. This allows a proponent to work with a single contact point through every stage of the project management process.

7. CEIP'S ROLE IN THE WA HYDROGEN PATHWAY

The CEIP could establish Western Australia's first commercial-scale green hydrogen production plant, which will integrate large scale renewable generation with hydrogen production through electrolysis. As a result, no greenhouse gasses will be emitted in this process.

CEIP will be one of the critical first steps of Western Australia's Hydrogen Pathway. Driving the success of CEIP, and more broadly the hydrogen economy in Western Australia is predicated on having a competitive price advantage and reducing barriers through government support.

While various parties have spoken positively about the potential of hydrogen in Western Australia, a slowness to move to implementing projects could see various stakeholders considering other investment and commercial opportunities outside of Western Australia.

Competitive price advantage

For CEIP to be competitive from inception and set up a strong foundation for success, the starting price for hydrogen would have to be competitive with current diesel prices. Initial indications are that the CEIP's hydrogen cost, assuming on site refuelling infrastructure, is almost on par with diesel prices. The marginal/small premium should not be seen as a deterrent for users to move to a cleaner fuel.

To build on this strong foundation, CEIP would then need to work towards being competitive with natural gas. The latest published price for natural gas in Western Australia is around $4.10/GJ (Dec 2019), which is largely representative of the average price over the past two years.

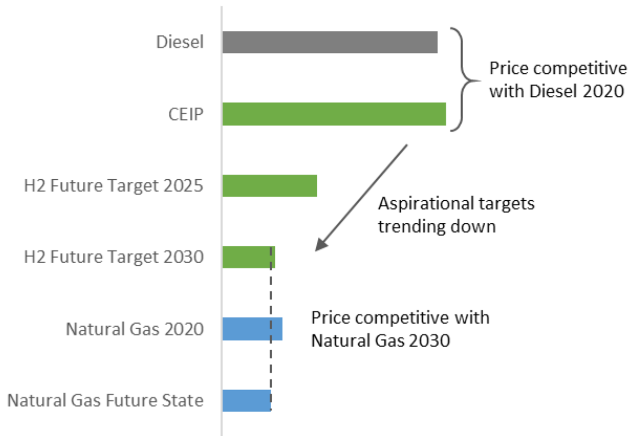


Figure 5: Competitive Price Landscape: Current & Future

Market discussions have referenced recent publicly announced targets, including the Federal Government's "H2 under $2/kg" and the target set in the Australian Hydrogen Roadmap (2018) of $2.50/kg by 2025.[8] These prices are largely aspirational and geared towards exports as such, they do not form a firm comparison point for domestic hydrogen offtake.

[8] National Hydrogen Roadmap, CSIRO, 2018

There is a clear gap to bridge to achieve this competitive future state. The CEIP will take one step towards bridging this gap, through the reduction of electricity costs. This could be achieved thorough co-location of the hydrogen production facility and the renewable power source. However, in doing so trucking costs, to get hydrogen to injection points, will increase.

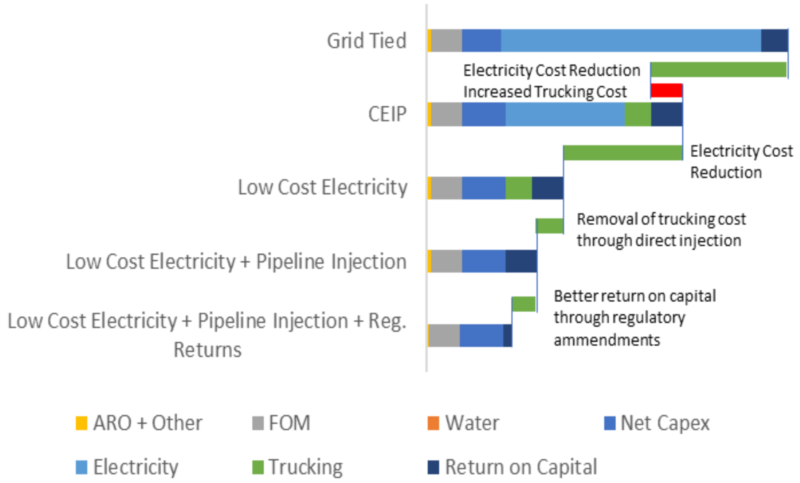


Figure 6: Cost reduction journey for WA Hydrogen

Therefore, unless the cost of electrolysers or renewable energy materially reduces in the short to medium term, broader regulatory and industry support from the Government will be required to bridge the price gap and meet the announced price targets.

An important role in improving the economic viability of Hydrogen projects in Western Australia is the support from the government. This support helps remove barriers to cost and use.

ATCO will continue to engage with the Government to facilitate reviews of existing legislation, regulations and legal frameworks. Areas of engagement with the government that ATCO will focus on will include:

- Funding grants supporting the economic viability of early stage hydrogen projects such as the CEIP
- Legislative amendments to mandate hydrogen for network blending
    - Legislative green gas blending targets
    - Economic regulation framework that incentivises green hydrogen investment and sustainable low-cost hydrogen production
- Allowing green hydrogen production facilities to be included in the RAB for pipeline operators

As previously stated in this report, the JTSI can provide information on statutory requirements and manage and coordinate approvals applications across Government. It can also assist with identifying the potential impacts of the proposal on matters including infrastructure, the environment and regional communities, and give advice on any social considerations that may arise.

APPENDIX A: TECHNICAL INFORMATION

Item	Value (units)
Forecast CAPEX[9]	$46.1m
Forecast OPEX[10]	$1.2m p.a.
Estimated direct FTE employment numbers	50+ during construction 20+ ongoing
Suggested project location	Warradarge Wind Farm, 233km north of Jandakot Industrial Estate in the Shire of Coorow
Estimated year of construction start	FID Dec 2021
Construction duration	12 to 18 months
Diesel displacement	6,635 KL/year
Carbon emissions reduction	10754 t/year
Sizing of additional renewable generation	Behind the meter wind power, modelled annual energy production, after other losses: 588 GWh
Capacity factor of additional renewable generation	~80%
Sizing of proposed electrolysis plant	10MW.
Sizing of proposed storage facilities[11]	4 tons
Pressure of proposed storage facilities[9]	Hydrogen: 30MPag at compressor outlet
Forecast annual production[12]	1,267 t p.a.
Forecast annual electricity consumption of electrolysis unit	72,251 MWh p.a.
Forecast annual water consumption of electrolysis unit[13]	31,836 KL p.a.
Forecast annual electricity consumption of balance of plant	6,570 MWh p.a.

[9] CAPEX to nominally include major plant costs, minor equipment, labour, site development, electrical integration, grid connection, project management
[10] OPEX to nominally include fixed and variable operating and maintenance costs
[11] Hydrogen storage facilities and other
[12] Hydrogen and other products
[13] Assuming 365 days a year operation with an availability factor of 75%

APPENDIX B: CEIP LOCATION SELECTION

Introduction

The CEIP Feasibility Study determined that the Warradarge Wind Farm site was the preferred site CEIP hydrogen facility however several sites within the Warradarge Wind Farm site were identified as potential locations for the hydrogen production, storage and loading facility.

Background and Context

The CEIP hydrogen production facility requires (peak load of 10 to 12MW) of electrical energy and 71m3 / day of raw water.

The electrical energy is available at 33kV at the existing Warradarge Wind Farm substation. The power is proposed to be reticulated by 33kV overhead power line to the proposed hydrogen production sites. It is noted that the all cabling on the Warradarge site is underground between the wind turbines. The route proposed to the used follows the north boundary fence and it is thought that this would be acceptable to the landowner but confirmation of this has not been confirmed at this time. The initial design of the electrical reticulation system would allow for maximum energy transfer of 25MW to take into account future expansion of the electrolyser.

An alternative electrical connection being considered is to tie into the one of the existing wind farm collector circuit by using a ring main unit to provide a spare feeder that would supply energy to the hydrogen facility. This option would require a different metering point than the dedicated feeder option proposed above. This would add slightly more complexity with the electrical arrangements and any outages on that feeder would affect both the wind collector circuit and the hydrogen facility, but these are thought to be manageable.

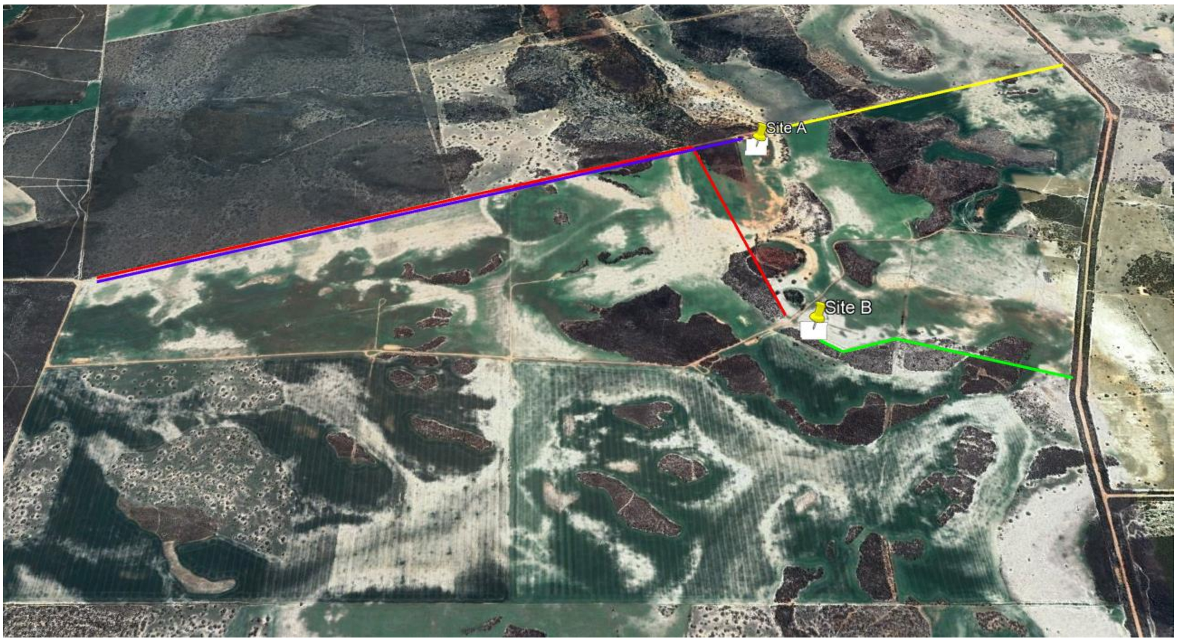
There is an existing water bore for the wind farm is proposed to be used to supply the hydrogen facility with the required amount of water. Confirmation of the long term bore capacity and water quality to be confirmed as part of future studies.

Decisions Required

The trade of study is to determine the lowest cost location for the hydrogen production facility.

Options Developed

Figure 1: Site A and Site B are shown below with Transmission Circuits and Access Road options.



Site B location with Wind Farm collector circuit shown in red.

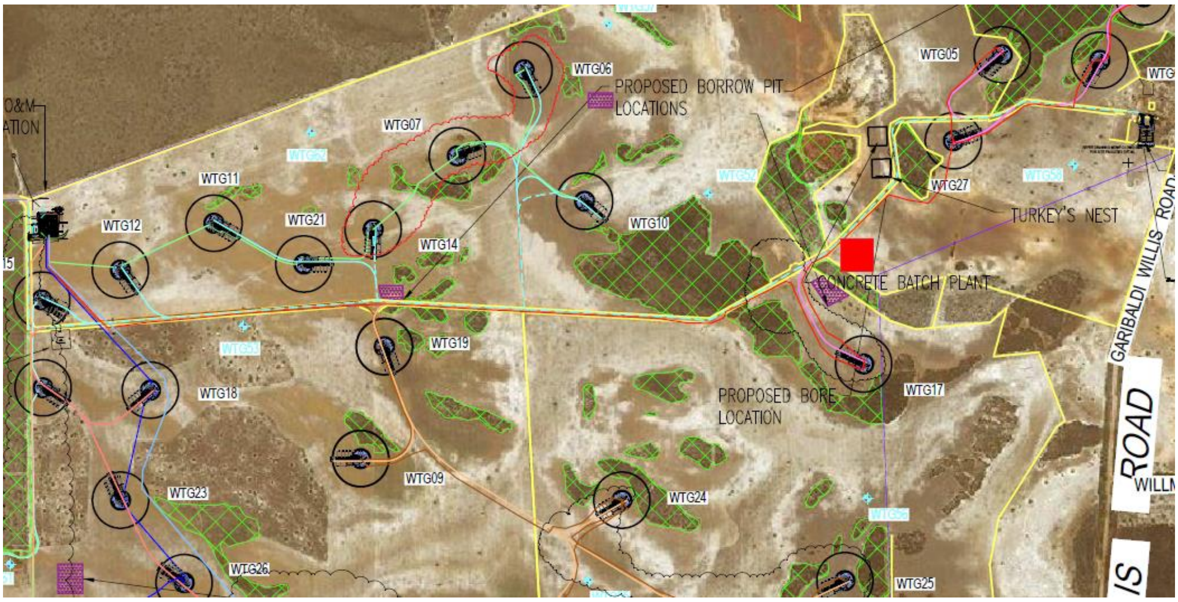


Table 1 Options considered

Option	Title	Description
A	Site A on the northern boundary.	Overhead electrical connection at 33kV from the Warradarge Wind Farm substation along the northern boundary 4.3km in length. Access road from Garibaldi Willis Road along the northern boundary 2.5km in length Water connection is assumed to be the same for all options and no allowance for additional bores has been included.
B1	Site B Central location with overhead transmission	Overhead electrical connection at 33kV from the Warradarge Wind Farm substation along the northern boundary and then across the site in a southerly direction to the selection site approximately central between WTG17 and WTG27 5.6km in length. Both sections are overhead lines. Access road from Garibaldi Willis Road along a central access point 1.5km in length Water connection is assumed to be the same for all options and no allowance for additional bores has been included.
B2	Site B Central location with part overhead transmission and part underground	Overhead electrical connection at 33kV from the Warradarge Wind Farm substation along the northern boundary and then across the site in a southerly direction to the selection site approximately central between WTG17 and WTG27 5.6km in length. Only the first section is overhead line with the second section being underground cable. Overhead section 3.9km and underground section 1.7km. Access road from Garibaldi Willis Road along a central access point 1.5km in length Water connection is assumed to be the same for all options and no allowance for additional bores has been included.
C	Site B with underground connection to wind farm collector circuit.	Underground electrical from Wind Farm Collector Group 2. The 33kV cable between WTG17 and WTG27 would be cut and the RMU installed. A joint in the collector circuit would be required. It is assumed that the RMU would be adjacent to the hydrogen facility, which would be connected by a short underground cable to the main switchboard approximately 100m in length. Access road from Garibaldi Willis Road along a central access point 1.5km in length Water connection is assumed to be the same for all options and no allowance for additional bores has been included.
D	Hydrogen Facility located adjacent to the Warradarge Wind Farm substation.	Direct electrical connection to the Warradarge Wind Farm substation assume to be approximately 100m. Access road from Garibaldi Willis Road for about 7km depending on the route taken. Water connection would require a larger pump station and piping to reach the substation.

Costs

Budget costs for the transmission connection and access road for each of the options is summarised below in Table 2.

Table 2 Criteria and ranking for the assessment

Option	Overhead Site A	Overhead Site B	Overhead / Underground Site B	Collector Circuit Site B	Site D Warradarge Substation
Transmission	354,000	462,000	912,000	345,000	0
Access Road (Sealed)	2,500,000	1,504,000	1,504,000	1,504,000	7,000,000
Access Road (Unsealed)	1,500,000	902,400	902,400	902,400	4,200,000

Discussion and Conclusion

The cheapest option is the unsealed access at Site B with an electrical connection to the wind farm collection circuit 2 at $1,247,400.

The most expensive option is the sealed access road to Site A with the overhead transmission connection at $2,854,000.

Site D is included as a reference base case only as the cost of the access road and the water connection far outweigh that of either Site A or Site B. The cost of a sealed access road to the Warradarge substation site is of the order of $7,000,000.

The budget costs for access road are significantly higher than the transmission costs for all options with the exception of underground cable option and the unsealed access road to Site B where costs are almost equal. This means the road length is far more significant that than transmission length. The ideal location is therefore as close to an existing access road as practicable.

Given the proximity to the existing bore then and relative closeness to Garibaldi Willis Road Site B is preferred over Site A.

The sealed access to Site B is $600,000 more than the unsealed option. Given the limited amount of movements in the first stage then the unsealed option is most likely preferred on a cost basis.

The use of the existing underground wind farm collector network saves $560,000 compared to installing a new underground connection from the northern boundary. Given the minimal added complexity to metering then this is considered the preferred option that is also the cheapest at $1,248,400.