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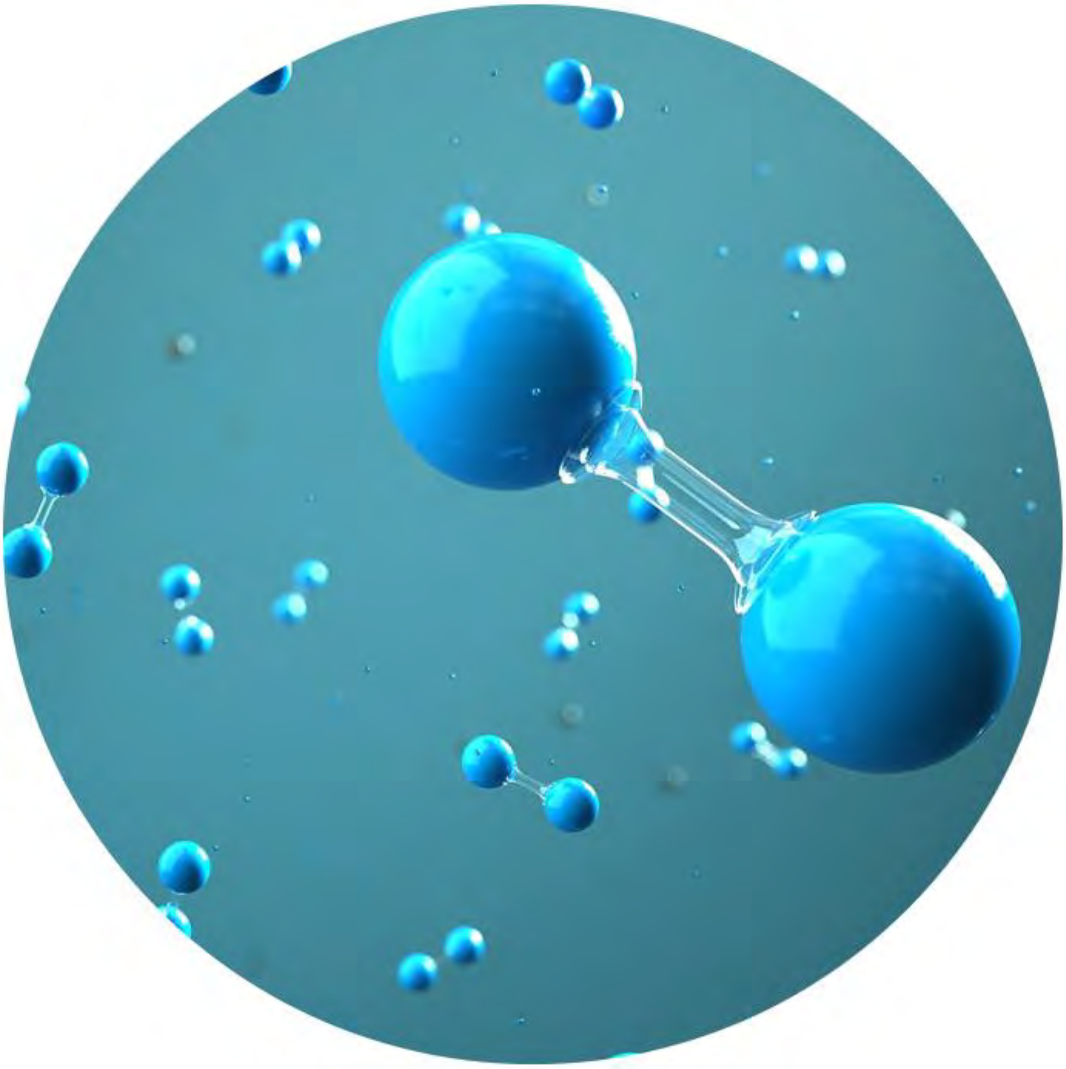

Stanwell Corporation Limited

Central Queensland Hydrogen Project

Feasibility Study Report

Current as of June 2022

For Public Release

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Document guide

This Feasibility Study Report (the Report) was prepared for the purpose of advancing the Central Queensland Hydrogen Project (the CQ-H_2 Project or the Project) from Concept to Feasibility. The report sets out the scope, approach and conclusions of the Feasibility Study and identifies a clear pathway to Front End Engineering Design (FEED).

The report focuses on both Phases of the Project. Phase 1 will involve production of 100 tonnes per day (tpd) of liquefied hydrogen, with an additional 700 tpd in Phase 2, for a total of 800 tpd (Phase 1+2). Phase 1 is planned for commencement in 2026, with scale-up to Phase 2 in 2031. Phase 1 has been assessed in detail, whilst Phase 2 has been assessed in concept. The understanding of Phase 2 will be further developed in FEED. Consideration of Phase 2 has been included in recommendations and decisions pertaining to Phase 1.

Supporting information is referred to using footnotes instead of appendices and a listing of the supporting information is presented in the form of a document list.

The report has been structured around the Project workstreams, being technical, commercial and social / stakeholder (also referred to strategic [1]). These workstreams operated under a project management umbrella.

The structure of the report is as follows:

[1] At the Project outset, the workstreams were defined as technical, commercial and strategic. During the course of the Feasibility Study, it was recognised that the strategic workstream was better described as social/stakeholder engagement and considerations.

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Acronyms, abbreviations and definitions

Acronym / Abbreviation	Description
A$ / $ / AUD	Australian dollars
AACE	Association for the Advancement of Cost Engineering
ACHA	*Aboriginal Cultural Heritage Act 2003* (Qld)
AEM	Anion exchange membrane
AEMO	Australian Energy Market Operator
APA	APA Group
APC	Announced Pledges Case
ARENA	Australian Renewable Energy Agency
ASU	Air Separation Unit
BKGGAS	Black coal gasification
BOG	Boil off gas
BoP	Balance of plant
BPICs	Best Practice Industry Conditions
BPP	Best Practice Principles
BRGAS	Brown coal gasification
BTM	Behind-the-meter
C1 / C_1	Methane
C2 / C_2	Ethane
CAPEX	Capital expenditure
CCS	Cargo Containment System (@ LH2 ship) / Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CEDI	Continuous electro-deionisation
CEFC	Clean Energy Finance Corporation
CHMP	Cultural heritage management plan
CO_2e	Carbon dioxide emissions
CoC	Cycles of concentration
COD	Commercial Operations Date
Consortium	Stanwell, Iwatani, KHI, Marubeni, KEPCO, and APA
COPV	Composite overwrapped pressure vessel
CP	Coordinated Project
CQ-H_2 Project / the Project	Central Queensland Hydrogen Project
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CW	Cooling Water
D&C	Design and construct
DA	Development Approval
Demonstration Project	10 MW hydrogen electrolysis project at Stanwell Power Station
DES	Department of Environment and Science
DTMR	Department of Transport and Main Roads
DOR	Department of Resources
DSDILGP	Department of State Development, Infrastructure, Local Government and Planning
DW	Drinking Water
EA	Environmental authority
ECI	Early contractor involvement
EDQ	Economic Development Queensland
EMP	Environmental Management Plan

EOI	Expression of Interest
EOL	End of Life
EP Act	*Environmental Protection Act 1994*
EPBC Act	*Environmental Protection and Biodiversity Conservation Act 1999*
EPC	Engineering Procurement and Construction
EPCM	Engineering Procurement and Construction Management
ERA	Environmentally relevant activity
ERS	Emergency Release System
ESG	Environmental, social and governance
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FEED	Front End Engineering Design
FL	Fishermans Landing
FID	Final Investment Decision
FOB	Free on board
FTE	Full time employee
GAWB	Gladstone Area Water Board
GBRMPA	Great Barrier Reef Marine Park Authority
GH2	Gaseous hydrogen
GHe	Gaseous helium
GHG	Greenhouse gas
GN2	Gaseous nitrogen
GO	Guarantee of origin
GOC	Government-owned corporation
GPC	Gladstone Ports Corporation
GRC	Gladstone Regional Council
GSDA	Gladstone State Development Area
GVA	Gross value added
GW	Gigawatt
GWh	Gigawatt hour
H_2 / H2	Hydrogen
ha	Hectare
HAZID	Hazard Identification
HLF	Hydrogen liquefaction facility
HGSA	Hydrogen Gas Supply Agreement
HGTA	Hydrogen Gas Transfer Agreement
HP	High pressure
HPA	Hydrogen Purchase Agreement
HPF	Hydrogen production facility
HSE	Health and safety executive
HV	High voltage
IA	Instrumental Air
IEA	International Energy Agency
IJV	Incorporated Joint Venture
ILUA	Indigenous Land Use Agreement
IRENA	International Renewable Energy Agency
IRR	Internal rate of return
ISBL	Inside Battery Limits

IW	Industrial Water
Iwatani	Iwatani Corporation
JPMO	Joint Project Management Office
JPY	Japanese Yen
JSE	Japan Suiso Energy
JV	Joint venture
Kansai / KEPCO	Kansai Electric Power Company Incorporated
KHI	Kawasaki Heavy Industries Limited
kL	Kilolitre
kt	Kilotonne
ktpa	Kilotonnes per annum
kV	Kilovolt
LAS	Loading arm system
LCOGH	Levelised cost of gaseous hydrogen
LCOH	Levelised cost of hydrogen
LCOLH	Levelised cost of liquefied hydrogen
LFNPP	Local and First Nations Participation Plan
LGA	Local Government Area
LGC	Large-Scale Generation Certificate
LHGSA	Liquefied Hydrogen Gas Supply Agreement
LH2	Liquid/liquefied hydrogen
LLI	Long Lead Item
LNG	Liquefied natural gas
LOI	Letter of Intent
LOS	Letter of Support
LP	Low pressure
LPG	Liquefied petroleum gas
LUP	Land Use Plan
MAOP	Maximum allowance operating pressure
Marubeni	Marubeni Corporation
MCA	Multi-criteria assessment / multi-criteria analysis
MECG	Mutli Element Gas Containers
MEDQ	Minister for Economic Development Queensland
METI	Japanese Ministry of Economy, Trade and Industry
MHF	Major Hazard Facility
MITI	Ministry of International Trade and Industry
ML	Megalitre
MLI	Multi-layer insulation
MNES	Matters of National Environmental Significance
MOF	Marine offloading facility
MOU	Memorandum of Understanding
MR	Mixed refrigerant
MSES	Matters of State Environmental Significance
Mt	Million tonnes
MTO	Material take off
MW / MW_{AC}	Megawatt
MWh	Megawatt-hour
Native Title Act	*Native Title Act 1983* (Cth)

NDA	Non-disclosure agreement
NEDO	New Energy and Industrial Technology Development Organization
NEM	National Electricity Market
NZE	Net zero emissions
O2 / O_2	Oxygen
O&M	Operating and maintenance
OCG	Office of the Coordinator-General
OEM	Original equipment manufacturer
OPEX	Operating expenditure
OSBL	Outside Battery Limits
P2P	Peer-to-peer
P&G Act	*Petroleum and Gas (Production and Safety) Act 2004* (Qld)
PCCC	Port Curtis Coral Coast
PEM	Proton exchange membrane / Polymer electrolyte membrane
PEP	Project Execution Plan
Planning Act	*Planning Act 2016*
PO	*Purchase Order*
PPA	Power Purchase Agreement
QMCA	Queensland Major Construction Association
QPP	Queensland Procurement Policy 2021
QREZ	Queensland Renewable Energy Zone
RAP	Regulatory Approvals Plan
RE	Renewable energy
REZ	Renewable Energy Zone
RFI	Request for Information
RFQ	Request for Quote
RFSU	Ready for Start Up (final phase of construction, and an initial operation in which the plant is a mechanically completed and fully commissioned)
RMP	Risk Management Plan
RNTBC	Registered Native Title Body Corporate
RO	Reverse osmosis
RO / RO	Roll-on / roll-off
SDA	State Development Area
SDR	Stream day rate
SDWPO Act	*State Development and Public Works Organisation Act 1971*
SFA	Short Form Assessment
SIA	Social Impact Assessment
SIMOPS	Simultaneous operations
SIMP	Social Impact Management Plan
SIS	Social Investment Strategy
SMR	Steam methane reforming
SOEC	Solid oxide electrolyser cells
SOL	Start of Life
SOW	Statement of Work
SPL	Strategic Port Land
Stanwell	Stanwell Corporation Limited
SteerCo	Steering Committee
SWOT	Strengths, weaknesses, opportunities and threats
T&Cs	Terms and conditions

TIA	Traffic Impact Assessment
TIC	Total installed cost
TMR	Transport and Main Roads
tpa	Tonnes per annum
tpd	Tonnes per day
TUMRA	Traditional Use of Marine Resources Agreement
TUoS	Transmission user fees / Transmission Use of System (Fee)
VI	Vacuum insulation
WBS	Work Breakdown Structure
WHS Regulation	*Work Health and Safety Regulation 2011*
WWTP	Wastewater treatment plant
°C	Degrees Celsius

Executive summary

The CQ-H_2 Project (the Project) Feasibility Study has assessed the viability of a large-scale renewable hydrogen supply chain to Japan. The Feasibility Study (the Study) has been undertaken by a consortium of six companies (Stanwell Corporation Limited (Stanwell), Iwatani Corporation (Iwatani), Kawasaki Heavy Industries Limited (KHI), Marubeni Corporation (Marubeni), Kansai Electric Power Company Incorporated (KEPCO), and APA Group (APA) – collectively referred to as the Consortium) under the leadership of Stanwell and Iwatani. The objective of the Feasibility Study was to build upon the Concept Study and to further define the Project's technical solution, financial and commercial metrics and stakeholder dynamics, with an aim of developing and delivering a well-defined and understood project description which would form the basis for further project definition and development.

The Feasibility Study objectives were defined under three work streams – technical, commercial and strategic and were progressed simultaneously under a project management umbrella.

The Feasibility Study concluded that the CQ-H_2 Project is technically feasible. The Feasibility Study also determined that the Project is potentially commercially viable with appropriate Government support. The Feasibility Study further concluded that the Project's social, stakeholder and associated impacts will be positive.

This analysis supports the undertaking of a FEED phase that will provide sufficient information to enable an informed decision to be made to proceed or not with Project execution.

The Project has been assessed in detail for Phase 1, and in concept for Phase 2. Where applicable, considerations and requirements for Phase 2 have been included in the decisions for Phase 1. In the next phase (FEED), Phase 1 will undergo front-end engineering and design, and Phase 2 will be further developed.

The Feasibility Study concluded in June 2022, with the Feasibility Study Report reflecting the Project status as at the end of April 2022.

Project context and overview

Project background

There is an increasing focus in the domestic and global energy markets on renewable energy, and in particular on hydrogen as a vector for energy transport. Australia and in particular, Central Queensland, benefit from advantageous geographic conditions suited to the production of renewable energy (and consequently, renewable hydrogen). Central Queensland is also a highly suitable location due to its geographic proximity to key demand centres, such as Japan. Australia and Japan have a mutual ambition to develop a hydrogen economy and have set national targets in line with this.

The Consortium has extensive expertise across the hydrogen supply chain, including in large-scale project development, liquid hydrogen production, energy retail, transport sector manufacturing, hydrogen transport/distribution, and pipeline networks.

Policy and market environment

The policy and market environment for hydrogen is evolving, as global demand and consumer appetite for renewable energy and renewable supply chains grow. The CQ-H_2 Project has strong alignment with State and Federal roadmaps and policies pertaining to hydrogen initiatives and emissions reduction targets.

Key government policies, including the *Queensland Hydrogen Industry Strategy 2019 – 2024* and *National Hydrogen Strategy 2019*, are well-aligned with the CQ-H_2 Project, by virtue of their strong focus on development of a sustainable and commercially viable renewable hydrogen industry.

There is a high level of political and public support for hydrogen energy (and in particular, for renewable hydrogen) in the Australian environment, with demand and public sentiment also strong internationally. The demand for hydrogen is expected to increase as countries and industries transition to net zero.

Data from the International Energy Agency (IEA) *"Global Hydrogen Review 2021"* puts the global hydrogen demand in 2020 at 90 million tonnes (Mt). Per the IEA *"Net Zero by 2050"* report, demand is predicted to increase to 250 Mt/year under the Announced Pledges Case (APC, i.e., the assumption that all national pledges concerning net zero that have been announced are realised on time and in full), and 528 Mt/year under the Net Zero Emissions by 2050 Scenario (NZE, i.e., what is required to achieve net zero in the global energy sector by 2050). The greatest demand is anticipated to be from the industry sector, with transport, refining, power, synfuels, ammonia fuel production, buildings and grid injection sectors also anticipated to contribute to demand, but to a lesser extent.[2] [3]

The Advisian / Clean Energy Finance Corporation (CEFC) "*Australian hydrogen market study"* forecasts the delivered cost of gaseous green hydrogen (under base and (accelerated) scenarios) to move from $5.82/kg ($5.43/kg) in 2020 to $2.72/kg ($2.23/kg) by 2050. For export to Japan, the near term levelised cost of hydrogen (LCOH, including costs relating to the electrolysis plant, liquefaction plant, load-out facilities, transport vessel and receiving facilities) was estimated at $13.22/kg, with this forecast to decrease to $9.12/kg over the long term to 2050.[4]

Project progression

In 2019, Stanwell began to investigate the green hydrogen sector, with a strong interest in assessing the viability of establishing a commercial-scale green hydrogen project.

Stanwell completed a Pre-Feasibility Study into a 10-megawatt (MW) hydrogen electrolysis project at Stanwell Power Station (the Demonstration Project) in June 2019. In July 2019, Stanwell's Board approved the progression to a Feasibility Study for the Demonstration Project[5]. The Demonstration Project was not deemed to be viable and was discontinued.

In May 2020, Stanwell and Iwatani signed a Memorandum of Understanding (MOU) to undertake a Concept Study into a large-scale liquefied green hydrogen supply chain between Central Queensland and Japan. Following this, in July 2020 (as part of the 10 MW Feasibility Study) Stanwell and Iwatani engaged Advisian to undertake a Concept Study for investigating the potential of a large-scale / scaled-up hydrogen export project in Central Queensland.

Based on the findings of the Concept Study, in October 2020, Stanwell and Iwatani decided to proceed with a Planning Phase to further develop the CQ-H_2 Project. In anticipation of the next stage in the Project, Stanwell and Iwatani formed a consortium in November 2020. The Planning Phase was completed in August 2021.

In September 2021, Stanwell and Iwatani formed a broader Consortium with three leading Japanese companies (KHI, KEPCO, and Marubeni) and an Australian energy infrastructure business (APA) to undertake a detailed Feasibility Study into the CQ-H_2 Project. The Feasibility Study commenced in September 2021 and was completed in June 2022.

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[2] International Energy Agency (IEA), Global Hydrogen Review 2021 (updated November 2021, available at: https://www.iea.org/reports/global-hydrogen-review-2021)

[3] International Energy Agency (IEA), Net Zero by 2050 (October 2021, available at: https://www.iea.org/reports/net-zero-by-2050)

[4] Advisian and Clean Energy Finance Corporation (CEFC), Australian hydrogen market study (May 2021, available at: https://www.cefc.com.au/insights/market-reports/the-australian-hydrogen-market-study/)

[5] Stanwell Corporation Limited (Stanwell), Stanwell Hydrogen Project Feasibility Study (October 2020, available at: https://www.stanwell.com/energy-assets/new-energy-initiatives/stanwell-hydrogen-project/stanwell-hydrogen-project-3/ and https://arena.gov.au/knowledge-bank/stanwell-hydrogen-project-feasibility-study/)

Project supply chain

A high-level overview of the proposed CQ-H_2 Project and Gladstone region is provided in Figure 1 below.

Figure 1: Proposed CQ-H_2 Project and Gladstone region

Through the Feasibility Study, the Consortium continued to investigate a large-scale renewable hydrogen production facility (HPF) near Gladstone and a hydrogen liquefaction facility (HLF) at the Port of Gladstone. The Consortium set a production and offtake target of 100 tpd of renewable hydrogen by 2026, scaling up to a total of 800 tpd (with a maximum of 268,000 tonnes per annum (tpa), dependent on operation mode and availability) in 2031 to help meet demand from Japan's power generation sector.

Project objectives

Through the CQ-H_2 Project, the Consortium aims to achieve the following key objectives:

- Position Central Queensland as a preferred Australian renewable hydrogen hub by harnessing the region's renewable energy resources and high-quality infrastructure;
- Establish a first of its kind integrated hydrogen supply chain between Central Queensland and Japan;
- Achieve the target hydrogen pricing set by the offtakers, by deploying the supply chain at scale including production, liquefaction, and shipping of hydrogen;
- Improve the technology and commercial readiness of the Project by leveraging expertise across the supply chain and long-term partnerships with Japan's premier energy, gas, trading, and technology companies;
- Support Australian industry on the pathway to net zero carbon emissions through domestic supply of renewable hydrogen to major industrial users in Gladstone;
- Contribute to Australian, Queensland and Japanese Government ambitions for the hydrogen industry;
- Deliver significant economic and social benefits through employment and local business opportunities;

- Help the Consortium partners transition to a lower carbon future.

Consortium overview

The Consortium has strong primary technical expertise across the hydrogen supply chain as noted in the diagram below. Consortium partners have an interest in investing in multiple parts of the supply chain.

Figure 2: Consortium supply chain capabilities

Australian and Japanese Government involvement

The Consortium has established highly effective working relationships with all levels of government and with key government agencies. Letters of support for the Project have been provided by various parties and agencies, including the Premier of Queensland, Australian Renewable Energy Agency (ARENA), CEFC, the Prime Minister's Global Business and Talent Attraction Taskforce, Economic Development Queensland (EDQ), the Hon. Cameron Dick MP (Queensland Treasurer and Minister for Trade and Investment) and the Hon. Mick De Brenni MP (Minister for Energy, Renewables and Hydrogen and Minister for Public Works and Procurement), the Joint Project Management Office (JPMO), and Office of the Coordinator-General (OCG).

ARENA has provided a funding contribution of A$2.16 million towards the cost of the Feasibility Study.

Similarly, Japan's Ministry of Economy, Trade and Industry (METI) has confirmed that this project is necessary to strengthen the relationship between Japan and Australia, with METI making a ~$500,000 contribution to the Japanese Consortium partners' Feasibility Study labour costs.

Project schedule

The CQ-H_2 Project is focused on achieving the completion of Phase 1 in 2026 (commercial production commencing in Q1 2027), with Phase 2 coming online in 2031. Overall, the Project stages include:

- **Project Feasibility Study** (Sep 2021 – June 2022 [Complete]): increase engineering design definition and cost accuracy to Class 4 (±30%) and firm up offtake and joint venture arrangements;
- **Front-End Engineering Design (FEED)** (July 2022 to Q2 2023): further design definition and cost accuracy (Class 3 (±20%)), planning approvals and binding commercial arrangements;
- **Final Investment Decision (FID)** (Q3 2023);
- **Detailed design, construction, commissioning** (Q3 2023 – Q4 2026);
- **Commercial production** (Q1 2027).

`Feasibility Study approach

The Feasibility Study approach involved three workstreams (technical, commercial, and strategic), under a project management umbrella. The strategic workstream includes social and stakeholder considerations, and as such will be referred to in this document as either the Strategic workstream or Social and Stakeholder workstream. These terms are used interchangeably throughout the Feasibility Study.

The Feasibility Study report provides a high-level overview of the technical, commercial and strategic solutions pertaining to the Project, a summary of the approach to risk management and regulatory approvals, detail on the execution strategy for Phase 1, the Phase 2 pathway, and proposed next steps for the Project. Additional context is provided throughout the report and with further detail referenced in the supporting information.

The Feasibility Study was undertaken in collaboration with advisors including Advisian/Worley (technical advisor), Deloitte (commercial & financial advisor), Advisian (stakeholder advisor) and MinterEllison (legal advisor).

The Feasibility Study sought to achieve the following key objectives:

- Assess the commercial, technical and strategic viability of the Project;
- Identify a preferred reference project including scale, location, design, technology selection, cost estimates (Class 4) (with sufficient confidence and reliance) and development pathway for project phases;
- Secure offtake agreements for the hydrogen output of the project (which will become binding subject to successful completion of FEED);
- Complete the necessary project development steps to provide sufficient certainty to enter the FEED stage, including securing energy, land, water, port, and other infrastructure;
- Prepare a feasibility study report to support a decision from consortium partners on whether to proceed to the FEED stage.

Assessment framework

The workstreams for the Feasibility Study are outlined below:

Figure 3: Feasibility Study workstreams

Technical Workstream

- Complete Class 4 (+/- 30%) design and cost estimates
- Undertake Early Contractor Involvement (ECI) with OEMs
- Complete due diligence on proposed production land and port site for liquefaction and shipping and prepare sale/lease contracts
- Develop supply approach for power and water, including submitting connection applications to Powerlink and GAWB
- Develop detailed planning and regulatory approvals pathway
- Complete environmental and social assessments

Commercial Workstream

- Confirm offtake/market arrangements and develop binding term sheets
- Complete project financial modelling
- Complete market sounding for renewable energy (RE) and conclude non-binding term sheets with RE projects (~1000MW)
- Identify project partners and develop Joint Venture (JV) structure and documents to enable execution prior to FEED
- Develop funding strategy including commencing Government funding processes

Strategic Workstream

- Develop and implement stakeholder engagement strategy
- Secure and maintain support from key stakeholder groups
- Complete social impact assessment including cultural heritage and native title
- Assess workforce/skills and local content/manufacturing requirements and opportunities
- Secure Board, Shareholder, Government approval to move to FEED stage
- Manage policy and regulatory issues

Project Management

- Complete project execution plan and schedule
- Develop contracting strategy and pre-qualify and qualify suppliers
- Complete Request for Proposals to identify participants for FEED competition
- Complete safety and risk assessment
- Plan for Integrated Project Management team for FEED stage

Identification of Reference Project

Reference Project at commencement of Feasibility Study

The Reference Project as at commencement of the Feasibility Study was characterised by:

- A HPF at Aldoga utilising electrolysers for the production of gaseous hydrogen (GH2), with storage in the form of dedicated onsite hydrogen storage tanks and pipeline storage;
- A dedicated hydrogen transport pipeline following the “Southern” route; and
- A HLF and liquid hydrogen (LH2) wharf loading facilities located at the Port of Gladstone.

The planned production was 100 tpd for Phase 1, scaling up to 880 tpd for the Phase 1+2 development. The renewable energy supply was to be generated by a combination of time-of-day matched wind and solar sources. Offtake was to be primarily international export of the LH2 product, with the potential for domestic offtake. Project funding was anticipated to be a mix of grant funding, equity funding and concessional debt funding.

Reference Project to be taken into FEED

The Project concept was refined during the Feasibility Study. The revised Reference Project now includes:

- An optimised HPF layout at Aldoga with strategies and recommendations on hydrogen electrolysis technology to take forward into FEED (GH2 storage will be via dedicated onsite hydrogen storage);
- A dedicated hydrogen transport pipeline; and

- Greenfield HLF and LH2 wharf loading facilities located at Fishermans Landing, Gladstone..

Upstream/midstream facilities were optimised and plant throughput was revised to 800 tpd for the Phase 1+2 development. The energy supply arrangements were advanced during the Feasibility Study.

Technical solution

The technical solution for the Project required refinement and definition of variables across the Project components (HPF, pipeline, HLF, and loading & shipping) to develop the Phase 1 and Phase 2 Project solutions, including power, water, land, port, and infrastructure.

The Phase 1 technical solution involves a HPF producing an average stream-day rate of 100 tpd by electrolysis, with rated electrolyser capacity of 285 MW. The Phase 1 plant will occupy a 23-hectare (ha) footprint in the north-west of the proposed CQ-H_2 Aldoga site.

The Phase 1 HLF will be located in the Port of Gladstone (at Fishermans Landing) and will liquefy the HPF feed stream.

The Phase 1+2 Project will produce an average stream-day rate of 800 tpd by electrolysis, with rated electrolyser capacity of 2100 MW. The Aldoga site will be fully developed to allow for the Project's final 121.5 ha footprint.

Land requirements are as follows:

Table 1: Project land requirements

Land Requirement	Phase 1 (ha)	Phase 1+2 (ha)
HPF Plot	23	121.5
HLF Plot	10	50

Elements to be included in the development and assessment of the technical solution are identified in Table 2 below.

Table 2: Indicative average consumption parameters

Parameter	Phase 1 (Min | SDR | Max)	Phase 1+2 combined (Min | SDR | Max)
HLF feed rate[6] (tpd)	40 | 100 | 110	640 | 800 | 880
HPF target SDR[7] (tpd)	103	830
HPF electrolyser size – Rated (MW)	280	2100
HPF power demand – SOL (MW)	- | 210 | 290	- | 1,713 | 2,465
HPF water demand (ML/y)	600	4,800
HPF wastewater production (ML/y)	109	875
HLF power demand (MW)	- | 70 | 75	- | 560 | 600
HLF water demand (ML/y)	1,396	11,170*
HLF wastewater production (ML/y)	571	4,569*
HLF arrival pressure (barg)	17 | 28 | 33	17 | 30 | 33
HLF arrival temperature (°C)	-5 | 35-40 | 50	-5 | 35-40 | 50

**Potentially no change to Phase 1 through use of seawater exchange*

[6] HLF feed rate is the driver of the consumption parameters

[7] Stream-day rate

Power supply and load factor

Phase 1

In support of the Phase 1 development, approximately 1,320 MW of renewable energy is available via Stanwell's renewable energy portfolio. An overview of the potential commercial arrangements with power suppliers (that Stanwell is progressing to support CQ-H_2 energy requirements) are outlined below:

- Solar Farm No 1 ~350 MW;
- Wind Farm No 1 ~346.5 MW;
- Wind Farm No 2 ~310 MW;
- Wind Farm No 3 – 313 MW;
- Additional backup projects (Solar Farm No 2 – 49 MW, Wind Farm No 4 – 150 MW, Wind Farm No 5 – 252 MW).

The 'greening' of grid power using LGCs (or an alternative program if the LGC scheme is not extended past 2030) may also meet the renewable power definition.

The Load Factor assessment performed during the Feasibility Study found the optimum load factor for Phase 1 is achieved with electrolysis capacity of 285 MW at Start of Life (SOL) (305 MW at End of Life (EOL)) with a load factor of about 84%.

The proposed Phase 1 development reduces HPF output during the peak National Electricity Market (NEM) electricity demand in the evening to reduce exposure to high power supply costs.

Phase 2

Similar to Phase 1, solar and wind will be used primarily to supply renewable energy to the HPF and HLF for the full Phase 2 development.

Stanwell provided indicative wind profiles for modelling of the Phase 2 plant power requirement. It was found that a total of 5.0 GW of installed wind capacity and 2.8 GW of solar allows the operation of the Phase 1+2 HPF and HLF while limiting the need for spot power purchases at a practical level. It is, however, suggested that 5.5 GW of wind and 3.0 GW of solar be aimed for to reduce reliance on the grid and therefore reduce risk associated with exposure to power price fluctuations.

For Phase 2, an electrolyser design capacity of 2,100 MW at SOL (2,300 MW at EOL) is optimal with a corresponding load factor of 83%.

Again, increasing the volume of contracted renewable generation (thus reducing the reliance on grid imports) and increasing the NEM feed-in has a beneficial impact on overall economics.

Hydrogen Production Facility (HPF)

Phase 1

The HPF scope for Phase 1 included a site assessment and development of a HPF plot plan for the Aldoga facility, power transmission and network services, water supply and treatment, wastewater management, electrolyser plant, balance of plant, materials and structure/building, and compression and storage.

The Aldoga HPF technical due diligence found no specific constraints/limitations regarding the site's ability to accommodate both Phase 1 and Phase 2 Project development scenarios. A phased approach to site development was recommended, with a split pad arrangement shown in the resulting plot plan to optimise staged use of capital and hydraulic considerations. Power supply for Phase 1 was proposed via two transmission sources: a 33 kilovolt (kV) behind-the-meter (BTM) connection and a 275 kV NEM connection from the Larcom Creek substation.

Various water supply options were explored, with the analysis determining that a raw water supply was the preferred solution. It provided the most cost-effective source for Phase 1, as well as representing the least risk from an Environmental Approvals perspective. This raw water supply would require pre-treatment involving a single pass reverse osmosis (RO) and continuous electro-deionisation (CEDI) demineralisation system.

Water demand for the Phase 1 HPF was also significantly reduced from volumes determined in the Concept Study through specification of air-cooled plant.

A two-train electrolyser supply strategy was recommended in the Feasibility Study for progressing into FEED. The key benefits of this strategy were to maintain a competitive tension between OEMs during FEED, in the delivery of the Phase 1 equipment and in development of technology leading into Phase 2, and also in reducing the impact of any potential individual vendor electrolyser package performance. A competitive OEM approach is to be progressed in FEED to ensure competitive electrolyser vendor and technology selection. Some assumptions have been made in the Feasibility Study pertaining to electrolyser technology type and configuration. These assumptions are reflected in the Feasibility Study Report and financial modelling and analysis and will be improved and validated at the FEED stage.

Compression for storage and pipeline transportation will also be required for HPF Phase 1. Storage is required for balancing the interface between the variable production at the HPF and effectively continuous production at the HLF. The preference for initial compression is positive displacement type (non-lubricating reciprocating compression). A non-lubricating reciprocating compressor is also preferred for storage compression, though other technologies should be reconsidered during FEED. Multi Element Gas Containers (MEGC) using a composite (predominantly fiberglass) material is preferred for the fixed storage solution.

Phase 2

The HPF scope for Phase 2 built on the scope for Phase 1.

Phase 2 of the HPF is expected to be located on the same site (Aldoga) as for Phase 1. The HPF plot plan for Phase 2 is largely to the east of the new drainage channel, enabling a natural separation to minimise simultaneous operations (SIMOPS) requirements, and to reduce construction risk during Phase 2 construction. Key considerations specific to Phase 2 include the site access and relocation of the Phase 1 high voltage (HV) switchyard.

To support the Phase 2 power requirement, significant upgrades to the electricity network would be required, with a new 500/275 kV network suggested (switchyard at the Larcom Creek substation).

Electrolyser selection in Phase 1 is anticipated to inform Phase 2, with the assumption being that the preferred Phase 1 vendors would be engaged to supply OEM equipment for Phase 2. The preferred vendors are likely to be the ones that best show a clear technology developmental pathway and can demonstrate industry-leading performance in driving down LCOH.

Key Phase 1 balance of plant (BoP) decisions and structural considerations have been carried through and are analogous for Phase 2. The compression solution for Phase 1 is anticipated to be scaled-up for Phase 2. Phase 2 storage will be informed by data and learnings available at the end of Phase 1 execution.

Hydrogen transport pipeline

Several hydrogen transport pipeline routes were evaluated in the Feasibility Study, however further evaluation will be necessary in light of land tenure constraints. Pipeline material, design and sizing was also evaluated. The pipeline constructed in Phase 1 will be scaled for Phase 2, with capacity to accommodate the full delivery rate for Phase 2.

Hydrogen Liquefaction Facility (HLF)

The scope of the Feasibility Study included the auxiliary elements of the HLF including utility (power supply, water supply), wastewater management, site selection, and wharf and access considerations. The liquefaction technology selection is outside the scope of the Feasibility Study. HLF technology will be assessed during FEED.

Phase 1

Considerations and facility elements pertaining to the HLF included the HLF receiving facilities, Fishermans' Landing site review, marine offloading facility, wharf facility including berth access, and utility connections.

The current 66 kV Ergon-owned electricity distribution network from Boat Creek substation (with the network being in turn, supplied from two incoming 132 kV lines) is insufficient for the Phase 1 HLF and future augmentation will be required.

Various water supply options were explored, with the analysis determining that a raw water supply is the most cost-effective.

With respect to the HLF receiving facilities, the assessment determined that the design of packages should be suitable for accommodating Phase 2 rates with minimal modification, as the pipeline is to be designed for Phase 2 rates.

The HLF site review took a multi-disciplinary approach and explored various elements focused around site history, geotechnical, environmental, ecological, cultural heritage, tidal levels, flooding (surface water), water, electrical, structural, civil earthworks, and plot size allowance. With respect to the HLF location, several options were considered and one has been taken forward as the preferred location for the HLF as it will accommodate Phase 2 expansion plans. Other considerations within the Feasibility Study focused on a marine offloading facility and berth access.

Phase 2

The HLF scope for Phase 2 built on the Phase 1 scope.

The double circuit 275 kV connection preferred for Phase 1 will be sufficient for the Phase 2 HLF power requirement. A number of alternatives are under consideration for the HLF Phase 2 water supply.

The Project will continue to investigate options for water usage reduction, particularly the use of seawater for cooling, as this currently makes up the majority of the water demand for the HLF. For Phase 2, the preferred wastewater disposal option is ocean outfall via seawater cooling circuit.

With respect to the HLF receiving facilities, these were designed to accommodate Phase 2 development flow condition with minimal changes. The Fishermans Landing site has suitable space for development of infrastructure for Phase 2 and is thus suitable for the Phase 2 expansion.

Cost estimate (Phase 1 & 2)

The required level of estimation confidence is achieved through a combination of cost inputs including vendor budget prices, in-house estimates based on same or similar equipment design/sizes and factoring of known bulk / commodity prices.

The capital cost estimates (March 2022 $) are as below:

Table 3: Cost estimate – CAPEX

Element	Phase 1	Phase 2 increment	Phase 1+2 total
Upstream[8]	$1.18 billion	$5.30 billion	$6.48 billion
Midstream[9]	$2.68 billion	$5.59 billion	$8.28 billion
Total	**$3.87 billion**	**$10.89 billion**	**$14.75 billion**

The operating cost estimates (March 2022 $) are as below:

Table 4: Cost estimate – OPEX

Element	Phase 1	Phase 1+2 total
Total upstream OPEX (average)	$106.29 million/year	$622.10 million/year
Total midstream OPEX (average)	$102.82 million/year	$353.96 million/year
Overall OPEX (average)	**$209.11 million/year**	**$976.06 million/year**

It is anticipated that the largest contributor to OPEX is power supply for both HPF and HLF.

Transport and logistics

The logistics study (undertaken as part of the Feasibility Study) addressed potential impacts associated with oversize modules, containerised freight, and traffic. Some local access and transport route constraints were identified, however appropriate solutions were recommended. No major transport/logistic impasses were identified.

Financial analysis

Financial model

The financial and commercial analysis included the development of a financial model. The financial model includes financial statements, as well as key project metrics including Levelised Cost of Hydrogen (LCOH), Net Present Value (NPV), and Internal Rate of Return (IRR) for the two structuring options being considered. The model considers three scenarios, the Base Case, Optimised Case and Stretch Case. Whilst the Base Case is reflective of the current market environment, the Optimised Case represents a more likely scenario that will benefit from advancements in technology and refined capital costs. The Stretch Case represents an optimistic scenario that reflects significant improvements in technology.

[8] Upstream encompasses HPF, storage and pipeline

[9] Midstream encompasses HLF and shipping

Project costs

Table 5: Whole of Life Project Costs - Base Phase 1 ($ Million)

Whole of Life Project Costs Base Phase 1	$FY2022 Real AUD (million)	$Nominal AUD (million)	$PV AUD (million)
Total Hydrogen plant	$4,626	$6,882	$1,962
Total Hydrogen pipeline	$94	$109	$68
Total Shipping	$6,115	$8,356	$3,296
Total Costs	**$10,834**	**$15,348**	**$5,326**

Note: The PV was calculated using a pre-tax, nominal discount rate of 8.23 percent by discounting the nominal cash flows to 1 July 2021.

Table 6: Whole of Life Project Costs - Base Phase 2 Incremental ($ Million)

Whole of Life Project Costs Base Phase 2 Incremental	$FY2022 Real AUD (million)	$Nominal AUD (million)	$PV AUD (million)
Total Hydrogen plant	$23,884	$37,322	$8,274
Total Shipping	$15,089	$22,316	$6,169
Total Costs	**$38,972**	**$59,638**	**$14,443**

Note: The PV was calculated using a pre-tax, nominal discount rate of 8.23 percent by discounting the nominal cash flows to 1 July 2021.

Tax and Accounting Considerations

The tax and accounting analysis firstly considered the alternative structuring vehicles that could be used for the Project. An Incorporated Joint Venture (IJV) was identified as the preferred structuring vehicle. The analysis subsequently considered the key tax and accounting considerations relevant to the structuring of the Project using IJVs under Structuring Options 1 and 2 (excluding Shipping & Receiving). The tax and accounting findings of the analysis were incorporated into the financial model.

The Project structure options are listed below:

- **Structuring Option 1:** HPF, Hydrogen Pipeline, HLF and Shipping & Receiving components are structured as four separate IJVs (“Option 1”)
- **Structuring Option 2:** HPF & Hydrogen Pipeline (combined), HLF and Shipping & Receiving components are structured as three separate IJVs (“Option 2”).

It is expected that Phase 2 of the Project will occur either within the existing IJVs incorporated as part of Phase 1, or new IJV(s) will be incorporated for the Phase 2 HPF.

Financial Modelling Outcomes

The pre-tax real discount rate applied across all scenarios in the model is 6.0 percent.

Levelised cost of gaseous hydrogen (LCOGH)

The Levelised Cost of Gaseous Hydrogen (LCOGH) reflects the pre-tax cost per kg of gaseous hydrogen delivered to the HLF without taking into consideration grants. If the Project is able to achieve the targeted efficiencies assumed under the Optimised and Stretch scenarios the LCOGH will reduce as per the table below.

Table 7: LCOGH for HPF and Hydrogen Pipeline without grants (AUD/kg)

LCOGH pre-tax	Base	Optimised	Stretch
Phase 1 *(without grants)*	$5.76	$4.89	$4.65
Phase 2 Incremental *(without grants)*	$4.25	$3.38	$2.79

Note: The levelised costs were calculated using a pre-tax, real discount rate of 6 percent, as at 1 July 2021.

Levelised cost of liquefied hydrogen (LCOLH)

The Levelised Cost of Liquefied Hydrogen (LCOLH) reflects the pre-tax cost per kg of liquefied hydrogen delivered to Japan excluding grants.

Table 8: LCOLH by Supply Chain Components (AUD/kg)

LCOLH pre-tax without grants	Base	Optimised	Stretch
Phase 1			
LCOLH - HPF and Hydrogen Pipeline contribution	$7.31	$6.20	$5.90
LCOLH – Total Shipping	$11.88	$11.31	$11.09
Phase 1 - Total Project LCOLH	$19.19	$17.51	$16.99
Phase 2			
LCOLH - HPF and Hydrogen Pipeline contribution	$4.56	$3.63	$2.99
LCOLH – Total Shipping	$3.40	$3.11	$3.00
Phase 2 - Total Project LCOLH	$7.95	$6.74	$5.99

Note: The levelised costs were calculated using a pre-tax, real discount rate of 6 percent, as at 1 July 2021.

Commercial feasibility

The CQ-H_2 Project offtake is predicated on the export market supply arrangements with hydrogen end users and refuelling companies in Japan. Liquid hydrogen in Japan will have direct end use in transportation while a substantial volume will be converted to gaseous hydrogen and is expected to have end-use in power generation and heavy industry including steel production.

The Consortium includes one of Japan's largest power utilities (Kansai Electric Power Company) and Iwatani Corporation, a leading player in hydrogen refueling station market in Japan, who are expected to be potential hydrogen offtakers for the first phase of the project.

Potential offtake structures

The Feasibility Study assessed two potential offtake structures for the sale of hydrogen to Japan.

Figure 4: Offtake Structure 1 - Similar to a Liquefied Natural Gas (LNG) Integrated Structure

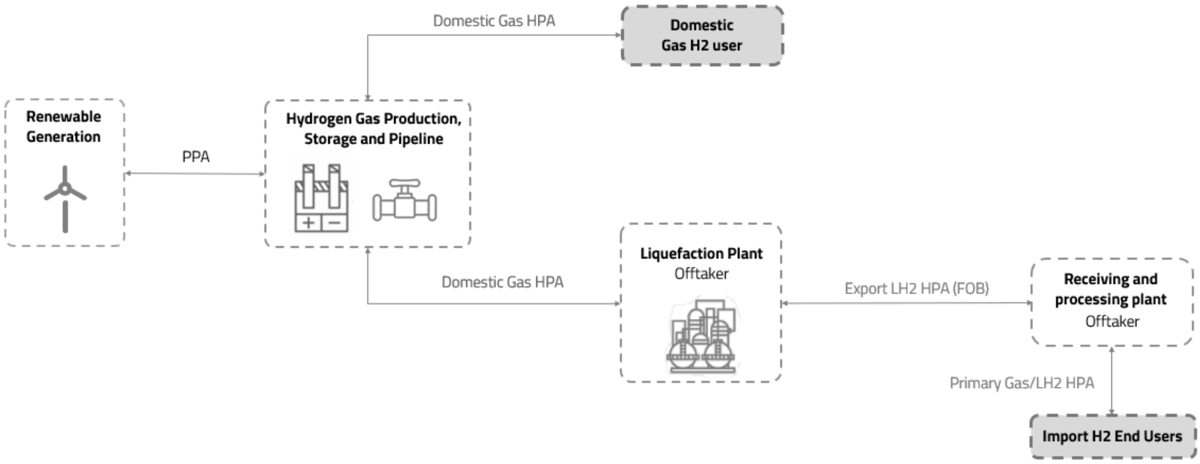
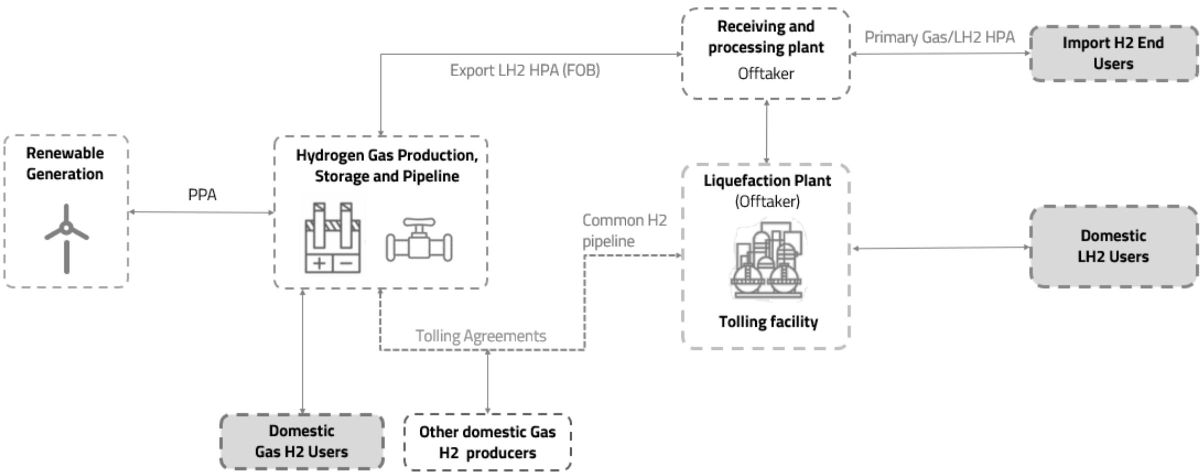


Figure 5: Offtake Structure 2 - Similar to a LNG Tolling Structure



Status of Offtake Discussions

The potential offtake arrangements of the CQ-H_2 Project will depend on the various funding options available mainly for the liquefaction facility, which is the likely offtaker for product from the production facility. The funding structure will be determined by the level of funding support that might be available for the project to make the offtake pricing commercially attractive for end use in Japan.

The ongoing offtake discussions currently indicate that the Phase 1 offtake terms would be driven by a short-term offtake arrangement until 2030. This arrangement may be subsequently integrated into rolling offtake agreements post 2030. The intention is to blend the Phase 1 pricing with Phase 2 pricing allowing the Phase 1 offtakers to share the pricing benefits through the economies of scale achieved through the larger Phase 2 project.

In addition to the Japanese offtake, the Project is investigating options in other Southeast Asian jurisdictions as well as engaging with local industry for domestic offtake.

Commercialisation Pathway

The commercialisation of the CQ-H_2 Project involves work on various work programs in parallel to confirm the readiness and viability of commercial arrangements to facilitate a Final Investment Decision (FID) by the Consortium. The work programs involve:

- Securing local community acceptance, regulatory approvals and managing risks pertaining to construction of a major project;
- Establishing exclusivity to potentially enter into short-term rolling agreements with the offtakers;
- Development of the Joint Venture (JV) structure with the Consortium Partners to ascertain the involvement of partners as asset owner / operator / developer across the supply chain from production to liquefaction and shipping;
- Further refinement of the financial model, confirmation of capital structure comprising debt, equity and grant funding sources;
- Establishing agreements for land, port and wharf facilities capable of accommodating docking and loading facilities;
- Establishing binding agreements for land for production and liquefaction facilities within the Gladstone State Development Area (GSDA);
- Establishing binding water supply agreements for electrolysis and cooling at production and liquefaction facilities;
- Undertaking detailed engineering design and improving cost accuracy (Class 3);
- Establishing renewable energy supply and electricity infrastructure capable of delivering the
- required energy for production and liquefaction;
- Establishing pipeline agreement for transportation of gaseous hydrogen via pipeline;
- Assessing the export market policy requirements to determine the long-term demand for hydrogen and ascertaining the production and supply chain investments are fit for purpose to meet the scale of export demand.

The Consortium has developed a costed pathway to reach FEED and FID. This pathway to FID will build on the Feasibility Study work and rigorously test the Project's technical, financial and commercial viability for hydrogen production, storage and liquefaction to provide strategic investment entry and exit options for the Consortium Partners.

Risk management

The risk management process for the Project was undertaken in accordance with Stanwell's Risk Management Policy and Framework, which uses the principles of ISO:31000.

As part of the approach to risk management, a series of risk workshops were conducted to identify the risks and opportunities associated with the risk categories identified in the Risk Management Plan (RMP). The risk analysis involved developing an understanding of the risk, causes and sources of risk, their positive and negative consequences, and the likelihood that those consequences will occur.

The risks have been segmented by workstream, and include technical risks, commercial risks, and social and stakeholder risks. Risks associated with the regulatory environment and COVID-19 have also been scoped. Risks have been assessed by the specific workstream teams and reviewed to ensure alignment between risk identification and treatment where risk classification overlap is present.

The Project's Risk Management Plan and Project Risk Register were reviewed and refreshed as part of the Feasibility Study.

Regulatory approvals

Regulatory approvals approach

Through the Feasibility Study, the Project sought to identify regulatory planning and environmental approvals, as well as non-regulatory agreements, required for Project development and execution. A detailed Regulatory Approvals Plan (RAP) was developed, along with a regulatory approvals register (included as part of the RAP). The RAP outlines approval strategy considerations, a preferred approval pathway, required regulatory approvals and associated assessment processes and timeframes, approval risk and opportunities, and potential constraints for the Project. The register details the legislation, relevant approval/consent/agreement, Project component(s) with the potential to trigger the approval requirement, the relevant administering authority, and an indicative assessment timeframe (from lodgement). The regulatory approvals schedule is based on current Project definition and understanding of the associated approvals required.

The regulatory approvals have been separated by Project phase (i.e., Phase 1 and Phase 2), with the strategy for regulatory approvals being developed for Phase 1 and a plan for development of the Phase 2 strategy in the future. The approvals have also been segmented by Project component, with separate applications to be lodged for the three distinct components (the HPF, hydrogen transport pipeline, and HLF/wharf), in alignment with the anticipated facilities ownership structure.

To streamline the regulatory approvals process, the Project has undertaken early engagement with regulators and government departments and will continue to engage with such bodies in the intervening period prior to commencement of FEED. The Project has also noted the inapplicability of the *Petroleum and Gas (Production and Safety) Act 2004* (Qld) (P&G Act) and has considered the approach that will be taken with respect to land acquisition and securing land tenure for the hydrogen pipeline.

It is planned that an approvals strategy for Phase 2 will be developed, which will identify new approvals and/or Phase 1 approvals amendments required.

Technical approvals

The focus of technical approvals is on planning and environmental considerations across both Commonwealth and State jurisdictions, including Matters of National Environmental Significance (MNES), Matters of State Environmental Significance (MSES), Development Approvals (DAs), and various other approvals/permits required by legislation. As part of the technical approvals development process, a preliminary environmental assessment was undertaken which identified potential impacts to MNES and MSES, and the Major Hazard Facility (MHF) status of the Project was evaluated.

Stakeholder approvals

Stakeholder approvals and requirements are centred around three key areas – Native Title (including Indigenous Land Use Agreements (ILUA)), Cultural Heritage and Tenure.

Social and stakeholder engagement

Engagement with stakeholders and management of social and environmental impacts are key to the success of the Project. Accordingly, several documents were prepared during the Feasibility Study to guide the Project's stakeholder engagement and social performance planning and implementation. The documents included:

- Social Baseline;
- Stakeholder Mapping and Issues Analysis;
- Stakeholder Engagement Framework inclusive of First Nations Engagement Framework and Community Education Framework ;

- Social Impact Assessment;
- Public Interest Assessment;
- Sustainability Assessment.

Other documents included are Stakeholder Engagement Approach Per Stakeholder Group and Cultural Heritage Database and Register results.

Social Baseline

The Gladstone region is home to a diverse range of industries including power generation, LNG processing, aluminium smelting and refining, cement and lime manufacturing, mining and industrial chemicals, and coal export. The manufacturing industry contributes 37.26% to the total output of the region.

The social baseline assessment provides additional detail on the location and population of Gladstone, traditional ownership, regional history, an industry profile, and social and community characteristics of the Gladstone region.

Stakeholder Mapping and Issues Analysis

Key Project stakeholders were identified in the course of the Feasibility Study. A stakeholder issues analysis was also completed for the Project, with issues identified relating to areas including: sustainable employment/training/supply opportunities, industry benefit sharing, environmental impact management, hydrogen and renewable energy industry growth, social impacts, industry engagement with regional community, Traditional Owners and other key stakeholders, safety management, and competition for resources.

Stakeholder Engagement

The objectives of the engagement activity were to understand the Gladstone region's current and historical socioeconomic environment, examine potentially significant project impacts and opportunities, and seek feedback on mitigation and management measures that are proposed.

Social Impact Assessment

A Social Impact Assessment (SIA) was completed for the Project, with key potential Project impacts identified. Potential opportunities associated with the Project were also identified.

Public Interest Assessment

A Public Interest Assessment was completed for the Project, with no public interest issues being identified that would prevent the Project from proceeding. Engagement outcomes suggest the community endorses the Project and the developing hydrogen industry, provided potential cumulative social impacts are managed appropriately.

Sustainability Assessment

A Sustainability Assessment was completed for the Project, including a framing and alignment workshop and Materiality Assessment. 145 potential material issues were identified, which were consolidated into 50 potential issues covering potential interactions between the Project and environmental, social and governance considerations. Existing and planned controls were also scoped for the purpose of addressing Project issues categories as highly material or material. The assessment identified sustainability as being a key driver for the Project.

Reduction in carbon footprint

The greenhouse gas (GHG) emission intensity of the CQ-H_2 Project is considered to be 0 kg CO_2e / kg H_2. Estimated emissions reductions under displacement scenarios were also calculated and are outlined below:

Table 9: Forecast annual emissions reduction

Phase	Displacing hydrogen yielded by natural gas reforming (ktpa CO_2e)	Displacing hydrogen yielded by coal gasification (ktpa CO_2e)
Phase 1	294	667
Phase 2	2,442	5,543

Phase 1 execution strategy

Phase 1 execution will involve advancement through FEED, FID and Detailed design, construction, and commissioning.

FEED

FEED is scheduled to commence in Q3 2022. In anticipation of this, a FEED plan has been developed for Phase 1 of the Project, with design considerations for Phase 2 taken into account in the design of Phase 1 to ensure no compromise to Phase 2 flexibility. Oversight and governance of the FEED Study will be achieved through the use of a Steering Committee. A draft FEED schedule has also been developed and is being finalised. Bridging activities will be undertaken in the pre-FEED stage.

A verifications list (detailing critical elements that need to be confirmed/approved by the Project) has been scoped.

The primary objective of FEED is to continue advancing the engineering detail, cost estimation and risk mitigation measures so that a FID can be made.

FEED budget

The budget for FEED is currently being determined and will be finalised prior to commencement of any activities associated with the FEED Study.

FEED funding

The FEED Study contributions (both cash and in-kind) will be determined prior to commencement of any activities associated with the FEED Study.

Letters of Intent (LOI) pertaining to the FEED Study have been obtained from all Consortium partners. Partner contributions to the FEED Study will be formalised via a MOU that is currently under development.

A summary of indicative FEED funding and FEED Study roles and proposed contributions is provided below.

Table 10: Proposed FEED Study roles

Company	FEED Study Role
Stanwell	• Australian study lead • Energy, electrolysis lead • Project development lead (infrastructure, planning, approvals)
APA	• Australian infrastructure group • Pipeline lead • Approvals support • Advice on study approach • Information gathering through local networks • Information on infrastructure specifications and costs
Iwatani	• Japan consortium and study lead • Liquefaction integration lead • Electrolysis support
KEPCO	• Providing adequate advice and information from the off-taker's perspective
Marubeni	• Commercial and finance lead • Advice on study approach • Information gathering through local networks • Information on Japanese off-takers • Advice on procurement contracts • Advice on project structuring • Advice on insurance
KHI	• Engineering including estimation and Schedule for liquefaction facilities, storage tank, liquefied hydrogen carriers • Information on equipment specifications and costs

The Project will be supported by advisors including across technical advisory (Worley/Advisian), commercial & financial advisory (Deloitte), stakeholder advisory (Advisian) and legal advisory (MinterEllison[10]).

Contracting and procurement

A strategy for contracting and procurement during FEED has been prepared. A high-level overview of the activities and estimated timeframes is provided below:

Table 11: Procurement activities and estimated timeframes[11]

Stage	Activity	Estimated Timing
Pre-FEED	Roll-over of the following advisors: • Technical advisor • Stakeholder engagement advisor • Financial/Commercial advisor	June 2022
	Probity advisor	June – July 2022
	Legal advisor	June – July 2022
	ECI for Construction Contractor/s	June – July 2022

[10] Other advisors will be engaged in the event of potential conflicts of interest

[11] To be confirmed

Pre-FEED & FEED	ECI for OEM Electrolyser	July 2022 onwards
FEED	OEM Electrolyser Shortlisting	July 2022 onwards
	Any other OEM engagement	September onwards 2022
	EPCM Procurement	January/February 2023 to June 2023

Plan to financial close (FID and Project delivery)

The plan to financial close (following successful completion of FEED) is as follows:

- Opportunity for Consortium partners to present results to their boards and get approval for FID;
- SteerCo to be held to make a decision to proceed to FID if all board approvals are granted (or approve necessary next steps to address issued flagged and get approval for FID);
- Once FID is achieved and Project is sanctioned, Consortium partners execute agreements negotiated during FEED (Joint Venture Agreements, Offtake Agreements, EPC contracting, Leases, Permits, etc.) and Project advances to financial close.

Phase 2 pathway

The CQ-H_2 Project is focused on Phase 2 commencement in 2031. The Project has been assessed in concept for Phase 2, with this phase to be further developed in FEED. Where applicable, considerations and requirements pertaining to Phase 2 have been incorporated in Phase 1 decisions. Planning for Phase 2 execution will begin during Phase 1 of the Project, with the anticipated start date of the planning Phase being Q4 2026.

Conclusions and next steps

The Feasibility Study has concluded that the CQ-H_2 Project is technically feasible, that it is potentially commercially viable with appropriate Government support. It has further concluded that, managed appropriately, the Project's social, stakeholder and associated impacts will be positive. This analysis supports the undertaking of a FEED phase that will provide sufficient information to enable a formal decision to be made to proceed with project execution.

Key Project output parameters as at the end of the Feasibility Study are outlined below.

Table 12: Key Project output parameters

Input	Phase 1	Phase 1+2 combined
Hydrogen source	Water electrolysis	Water electrolysis
First hydrogen date	1 January 2027	1 January 2031
Scale	100 tpd H_2 daily target	800 tpd H_2 daily target
Hydrogen environmental rating	Carbon neutral based on emission offsetting certificates	Carbon neutral based on emission offsetting certificates
Hydrogen quality	Purification for export (i.e. 99.999%)	Purification for export (i.e. 99.999%)
LH2 plant location	Fisherman's Landing	Fisherman's Landing
HLF inlet pressure	30 barg	30 barg
Carbon price	\$0 / ton	\$0 / ton
HPF grid connection node	Larcom Creek substation (275 kV)	Larcom Creek substation (275 kV)
Water supply philosophy	Surface water is acceptable	Surface water is acceptable
Electrolyser plant availability (Excl. planned shutdowns)	High i.e. 97-100%	High i.e. 97-100%
Metering and quality	GC based quality and HHV will be used as basis for sale	GC based quality and HHV will be used as basis for sale
Electrolyser Major Hazard Facility status	Notify as possible MHF to regulator	Yes
LH2 Major Hazard Facility status	Yes	Yes
Hydrogen ownership transfer location	At HLF Receiving facilities outlet	At HLF Receiving facilities outlet
HLF ultimate capacity (Maximum forward load rate excluding losses)	110 tpd	880 tpd
Market orientation	Export (to Asia)	Export (to Asia)

Next steps

The next steps in the Project will involve review and evaluation of this Feasibility Study report and associated supporting information by Consortium partners, to enable a formal decision to be made on progression to FEED.

Should the decision be made to advance to FEED, an MOU will be executed between the Consortium partners that will outline FEED Study roles and financial and in-kind contributions. Following this, pre-FEED bridging activities (including a planning phase) will commence.

1 Project context and overview

1.1 Project background

The global and domestic energy market is increasingly focused on renewable energy. A major challenge with the renewable sector is the vector transport medium for renewable energy, with hydrogen increasingly viewed as a potentially suitable vector. This view is recognised in the global and domestic environment.

The geographic conditions in Australia, and more specifically Central Queensland, are well disposed towards renewable energy production, and consequently, the use of renewable energy sources in the production of green hydrogen. Central Queensland is also well placed to supply green hydrogen by virtue of its close proximity to early demand centres and key Asian markets such as Japan.

The Project brings together expertise across the supply chain including a Queensland GOC with extensive experience in large-scale project development and energy markets, and Consortium partners with expertise in pipeline networks, energy retailing and hydrogen distribution.

Australia and Japan have a mutual ambition to develop a hydrogen economy to reduce emissions and secure future economic prosperity. The Japanese Government and major Japanese companies are targeting ‘net zero’ emissions by 2050, with hydrogen identified as a key mechanism to reduce emissions. The Australian Government has set a goal of becoming a ‘top three’ global hydrogen export nation by 2030, while the Queensland Government has established a Hydrogen Industry Strategy to position the state as a key exporter of hydrogen.

Unlocking the economic viability of renewable hydrogen will require staged deployment of large-scale projects to drive down costs, improve technology and activate markets.

1.2 Policy and market environment

International level

Hydrogen energy, particularly renewable hydrogen, is experiencing a high level of political and public support in the current Australian environment. Demand and public sentiment toward the transition to green hydrogen is also strong internationally. According to the IEA, political momentum for the use of hydrogen gathered significant strength in 2020-21, with 14 leading economies releasing hydrogen strategies over that period, including the UK and EU[12]. The demand for hydrogen is expected to increase as industries and countries transition to net zero emissions. The global demand for hydrogen was approximately 90 million tonnes (Mt) H_2 in 2020, with approximately 80% being produced using fossil fuels, and the vast majority of demand originated from industrial and refining. This represents an opportunity for Australia (and in particular, for renewable hydrogen projects such as the CQ-H_2 Project) to contribute to the decarbonisation of hydrogen moving forward.[13]

The IEA *“Net Zero by 2050”* roadmap modelling forecasts total consumption of hydrogen and hydrogen-based fuels to be 212 Mt/year by 2030 and 528 Mt/year by 2050 under the NZE by 2050 Scenario[14] (noting that the NZE is based on what is required to achieve net zero emissions in the global energy sector). The APC (which is based on the assumption that all national pledges relating to net zero are realised on time and in full) adopts a more conservative figure of 250 Mt/year by 2050. The greatest demand for hydrogen forecast under the APC and NZE Scenario is anticipated

[12] Recent EU announcements at https://ec.europa.eu/commission/presscorner/detail/en/IP_22_3131

[13] *Global Hydrogen Review 2021,* International Energy Agency, October 2021 [revised November 2021] (available at: https://www.iea.org/reports/global-hydrogen-review-2021)

[14] *Net Zero by 2050*, International Energy Agency, May 2021 [revised October 2021] (available at: https://www.iea.org/reports/net-zero-by-2050)

to be from industry, with demand also expected to originate from the transport, refining, power, synfuels, ammonia fuel production, buildings and grid injection sectors.[15]

The Glasgow Climate Pact, which was finalised at the COP 26 conference, also called upon signatories to:

> *"accelerate the development, deployment and dissemination of technologies, and the adoption of policies, to transition towards low-emission energy systems, including by rapidly scaling up the deployment of clean power generation and energy efficiency measures, including accelerating efforts towards the phase-out of unabated coal power and inefficient fossil fuel subsidies…"*[16]

This commitment places a sharp impetus on governments and industry to decarbonise and adopt lower carbon technologies such as green hydrogen. As a result, sentiment toward renewable hydrogen has never been stronger, which significantly adds to the export viability and long-term potential of the CQ-H_2 Project.

The demand for hydrogen will depend to a degree on the price at which it is sold on the market, impacting its competitiveness against other energy sources. For the price of green hydrogen to be competitive against other forms of energy, the cost of green hydrogen production will need to be competitive once the industry is established. In the earlier stages hydrogen industry will supported by Australian and Queensland Government policy measures to develop the hydrogen industry.

Federal level

Australian policy

There is strong alignment between the CQ-H_2 Project and Australian Government policies and strategies pertaining to hydrogen initiatives and emissions reduction. Key policies and strategies at the Federal level are detailed below.

The National Hydrogen Strategy 2019

Australia's National Hydrogen Strategy[17] was released in November 2019, and establishes a vision for an innovative, safe, clean and competitive hydrogen industry that is of benefit to all Australians, with an aim of positioning the hydrogen industry in Australia as a major international player by the year 2030. The CQ-H_2 Project will be key in positioning Australia as an international leader in the production of green hydrogen for domestic use and supply as an export. An overview of the strategy is provided in Figure 6 below.

Technology Investment Roadmap

The Technology Investment Roadmap[18] provides the pathway for accelerating development of emerging and new technologies through making the technologies competitive (in an economical sense) with established technologies, thus unlocking opportunities. Priority technologies (low emissions) are specified, including clean hydrogen, energy storage, carbon capture and storage, low carbon materials (aluminium and steel), and soil carbon.

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[15] *Global Hydrogen Review 2021,* International Energy Agency, October 2021 [revised November 2021] (available at: https://www.iea.org/reports/global-hydrogen-review-2021)

[16] Conference of the Parties serving as the meeting of the Parties to the Paris Agreement Third session Glasgow, 31 October to 12 November 2021

[17] *Australia's National Hydrogen Strategy,* Commonwealth of Australia, 2019 (available at: https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy)

[18] *Technology Investment Roadmap: First Low Emissions Technology Statement*, Australian Government Department of Industry, Science, Energy and Resources, September 2020 (available at: https://www.industry.gov.au/data-and-publications/technology-investment-roadmap-first-low-emissions-technology-statement-2020)

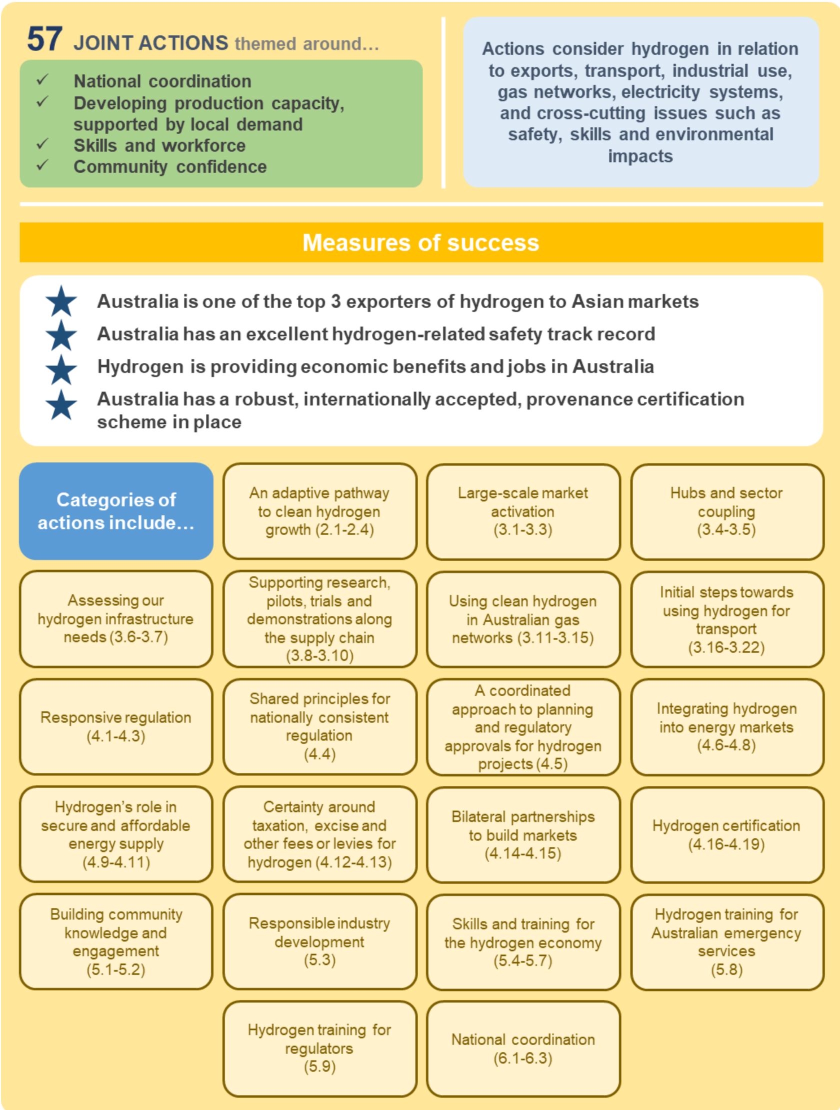
Long Term Emissions Reduction Plan

The Australian Government's Long-Term Emissions Reduction Plan[19] details the plan for Australia achieving net zero emissions by the year 2050. Under the plan, hydrogen is a 'priority technology'.

Future Fuels and Electric Vehicles Strategy

The Future Fuels and Electric Vehicles Strategy[20] details the plan for minimising the transport sector carbon footprint. The Australian Government, as part of the strategy, will work collaboratively with private sector in reducing vehicle emissions.

Figure 6: Australia's National Hydrogen Strategy[21]



[19] *Australia's whole-of-economy Long-Term Emissions Reduction Plan,* Australian Government Department of Industry, Science, Energy and Resources, October 2021 [updated October 2021] (available at: https://www.industry.gov.au/data-and-publications/australias-long-term-emissions-reduction-plan)

[20] *Future Fuels and Vehicles Strategy,* Australian Government Department of Industry, Science, Energy and Resources, November 2021 (available at: https://www.industry.gov.au/data-and-publications/future-fuels-and-vehicles-strategy)

[21] *Australia's National Hydrogen Strategy,* Commonwealth of Australia, 2019 (available at: https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy)

Australian market

The energy sector is of vital importance to the Australian economy, with the electricity, gas, water and waste services industry accounting for 2.5% of GVA ($46.469 billion) for 2020-21[22]. Similarly, export is key to the Australian economy. As at 8 April 2022, China, Japan, the US, Korea, India and the EU had the largest share of total exports, at 36.5%, 10.4%, 6.2%, 5.6%, 3.9% and 3.8% respectively[23]. The size of the Australian energy sector provides an opportunity for the CQ-H_2 Project to present hydrogen as an alternative to the more traditional power market offerings, and the significant share of Australian exports to Asia is indicative of geographic proximity benefits and established trade relationships.

Australia, and specifically Queensland, has strategic geographical advantages as both a producer and exporter of renewable hydrogen, due to the solar and wind profiles (Australia, as a continent, has the highest per square metre solar radiation compared to all other continents[24] and has some of the world's top wind resources[25]), abundance of land, and proximity to key export partners such as China, Japan, Korea and India.

Analysis conducted by Acil Allen[20] forecast the potential hydrogen export data over 2025-2040, with low, medium and high scenarios developed. The analysis predicted significant growth in the demand for Australian hydrogen (a ~10-fold increase from 2025 to 2040), with the majority of exports expected to be to Japan, Korea and China. This is presented in the table below.

Table 13: Potential Australian hydrogen export[26]

Importer	2025 (Mt/year)			2030 (Mt/year)			2040 (Mt/year)		
Scenario	**Low**	**Med**	**High**	**Low**	**Med**	**High**	**Low**	**Med**	**High**
Japan	0.017	0.106	0.275	0.182	0.368	0.803	0.392	0.852	1.979
Republic of Korea	0.008	0.024	0.053	0.040	0.078	0.167	0.107	0.234	0.570
China	0.001	0.003	0.008	0.012	0.038	0.079	0.089	0.197	0.464
Residual*	0.0007	0.004	0.009	0.008	0.018	0.038	0.033	0.068	0.169
Total	**0.026**	**0.136**	**0.345**	**0.242**	**0.502**	**1.088**	**0.621**	**1.350**	**3.180**

**Singapore and Rest of World*

As of November 2020, ARENA estimated the cost of hydrogen production in Australia to be between A$6-$9/kg (including capital investment for site preparation), with it being noted that a cost of A$2/kg would make green hydrogen cost competitive with fossil hydrogen[27]. As well as the expected growth in demand for renewable hydrogen in the medium to long term, the cost of producing hydrogen by electrolysis is expected to dramatically decrease in the coming years.

The Australian hydrogen market study report (prepared by Advisian for the CEFC), projected the base (accelerated) "farm gate" costs of green hydrogen to move from $3.88/kg ($3.46/kg) in 2020 to $2.81/kg ($2.29/kg) in 2030, and further decreasing to $2.09/kg ($1.64/kg) by 2050, whilst the base (accelerated) delivered cost was expected to move from $5.82/kg ($5.43/kg) in 2020, to $3.48/kg ($2.96/kg) in 2030, and decreasing further to $2.72/kg ($2.23/kg) by 2050 (with a

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22 *Why Australia Benchmark Report – Resilient economy,* Australian Trade and Investment Commission (available at: https://www.austrade.gov.au/benchmark-report/resilient-economy)

23 *Composition of the Australian Economy Snapshot,* Reserve Bank of Australia, 8 April 2022 (available at: https://www.rba.gov.au/education/resources/snapshots/economy-composition-snapshot/)

24 *Solar Energy,* Geoscience Australia (available at: https://www.ga.gov.au/scientific-topics/energy/resources/other-renewable-energy-resources/solar-energy)

25 *Wind Energy,* Geoscience Australia (available at: https://www.ga.gov.au/scientific-topics/energy/resources/other-renewable-energy-resources/wind-energy)

26 *Opportunities for Australia from hydrogen exports*, ACIL Allen Consulting for ARENA, 2018 (available at: https://arena.gov.au/knowledge-bank/opportunities-for-australia-from-hydrogen-exports/)

27 *Australia's pathway to $2 per kg hydrogen,* ARENAWIRE, 30 November 2020 (available at: https://arena.gov.au/blog/australias-pathway-to-2-per-kg-hydrogen/)

transition from truck delivery to pipeline delivery between 2025 and 2030). This is reflected in the forecast summary table below. Under an international offtake scenario where the hydrogen produced is exported to Japan, the near-term LCOH (inclusive of costs associated with electrolysis plant, liquefaction plant, load-out facilities, transport vessel and receiving facilities) was estimated at $13.22/kg, with the long-term forecast to 2050 predicting a decline in LCOH to $9.12/kg.[28]

Table 14: Hydrogen cost forecast summary[29]

Metric (cost $/kg)	2020	2030	2050
"Grey" hydrogen (farm gate)	2.20	2.29	2.29
"Blue" hydrogen (farm gate)	3.02	2.80	2.80
"Base" Green H_2 (farm gate)	3.88	2.81	2.09
"Accelerated" Green H_2 (farm gate)	3.46	2.29	1.64
"Nominal" Green H_2 (farm gate)	3.88	2.76	1.98
"Base" Green H_2 (delivered)	5.82	3.48	2.72
"Accelerated" Green H_2 (delivered)	5.43	2.96	2.23
"Nominal" Green H_2 (delivered)	5.82	3.42	2.60

The CSIRO *"National Hydrogen Roadmap"* (2018) showed that while the cost of PEM and alkaline electrolysis (i.e. electrochemical production methods that require the use of zero/low emissions electricity for green hydrogen production) was significantly higher in 2018, the expectation is that these will achieve a level of parity that will make them competitive with more traditional methods of hydrogen production around 2025[30].

Table 15: Hydrogen production technology comparison

Technology[31]	Base case $/kg (2018)	Best case $/kg (~2025)
PEM electrolysis	6.08-7.43	2.29-2.79
AE	4.78-5.84	2.54-3.10
SMR with CCS	2.27-2.77	1.88-2.30
BKGGAS with CCS	2.57-3.14	2.02-2.47
BRGAS with CCS		2.14-2.74

The development of large-scale hydrogen projects such as the CQ-H_2 Project (as well as the implementation of hydrogen hubs) will create economies of scale and synergies that will contribute to the growth of Australia's hydrogen industry and be key to bringing hydrogen production and supply costs down. This reduction in costs will contribute significantly to the growth of Australia's hydrogen export capacity.

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[28] *Australian hydrogen market study,* Advisian for Clean Energy Finance Corporation, May 2021 (available at: https://www.cefc.com.au/insights/market-reports/the-australian-hydrogen-market-study/)

[29] *Australian hydrogen market study,* Advisian for Clean Energy Finance Corporation, May 2021 (available at: https://www.cefc.com.au/insights/market-reports/the-australian-hydrogen-market-study/)

[30] *National Hydrogen Roadmap*, Commonwealth Scientific and Industrial Research Organisation (Bruce S, Temminghoff M, Hayward J, Schmidt E, Munnings C, Palfreyman D, Hartley P), 2018 (available at: https://www.csiro.au/en/research/environmental-impacts/fuels/hydrogen/hydrogen-roadmap)

[31] PEM = polymer electrolyte membrane; AE = alkaline electrolysis; CCS = carbon capture and storage; SMR = steam methane reforming; BKGGAS = Black Goal Gasification; BRGAS = Brown Coal Gasification

State level

State policy

There is strong alignment between the CQ-H_2 Project and Queensland Government policies and strategies pertaining to hydrogen initiatives and emissions reduction. Key policies and strategies at the State level are detailed below.

Queensland Hydrogen Industry Strategy 2019 – 2024

The Queensland Hydrogen Industry Strategy 2019 – 2024[32] was released in May 2019. An overview of the strategy is provided in Figure 7 below.

Climate Action Plan 2030

Queensland's Climate Action Plan 2030[33] is a Queensland strategy for pushing the state toward zero emissions, with an aim of hitting the target of 50% renewable energy by the year 2030 and net zero emissions by the year 2050, as well as emissions reduction below 2005 levels of 30% by the year 2030.

Advanced Manufacturing 10 Year Roadmap and Action Plan

The Queensland Advanced Manufacturing 10 Year Roadmap and Action Plan[34] details 17 actions targeting four key areas for positioning Queensland as an advanced manufacturing technologies leader. Per the roadmap, renewables and hydrogen are key export growth sectors.

Figure 7: Queensland Hydrogen Industry Strategy[19]

[32] *Queensland Hydrogen Industry Strategy 2019 – 2024*, State of Queensland, Department of State Development, Manufacturing, Infrastructure and Planning, May 2019 (available at: https://www.statedevelopment.qld.gov.au/industry/priority-industries/hydrogen-industry-development)

[33] *Queensland Climate Action,* The State of Queensland (Department of Environment and Science) (available at: https://www.des.qld.gov.au/climateaction)

[34] *Queensland Advanced Manufacturing 10-Year Roadmap and Action Plan*, State of Queensland, Department of State Development, Manufacturing, Infrastructure and Planning, November 2018 (available at: https://www.rdmw.qld.gov.au/manufacturing/strategy/advanced-manufacturing-roadmap-action-plan)

1.3 Project progression

In 2019, Stanwell began to investigate the green hydrogen sector, with a strong interest in assessing the viability of establishing a commercial-scale green hydrogen project.

Pre-Feasibility and Feasibility Studies (Demonstration Project) and Concept Study (Scale-Up Project)

Stanwell completed a Pre-Feasibility Study into a 10 MW hydrogen electrolysis project at Stanwell Power Station (the Demonstration Project) in June 2019. In July 2019, Stanwell's Board approved the progression to a Feasibility Study for the Demonstration Project[35]. In March 2020, ARENA announced a 25 per cent funding contribution to that feasibility study.

The feasibility study concluded that while the Demonstration Project was technically feasible, it would only be modestly commercially viable if it was able to attract a 'green premium' hydrogen offtake agreement and grant funding for a material portion of its capital costs. Given neither was available at the time, Stanwell decided to discontinue work on the Demonstration Project.

In May 2020, Stanwell and Iwatani (Japan's largest hydrogen supplier) signed a MOU to undertake a Concept Study into a large-scale liquefied green hydrogen supply chain between Central Queensland and Japan. Following this, in July 2020 (as part of the Feasibility Study for the Demonstration Project) Stanwell and Iwatani engaged Advisian/Worley to undertake a Concept Study for investigating the potential of a large-scale / scaled-up hydrogen export project in Central Queensland.

The Concept Study investigated green hydrogen production, liquefaction and export from the Port of Gladstone to Japan to help meet the expected requirements of the Japanese power generation sector. This involved a green hydrogen production facility connected via pipeline to a hydrogen liquefaction plant at Fishermans Landing at the Port of Gladstone.

The Concept Study was based on a phased hydrogen offtake model commencing liquid hydrogen export at a scale of 100 tpd (Phase 1) in 2026, and scaling-up to at least 770 tpd (Phase 2) in 2031 from Gladstone.

The concept explored key development concepts for both phases of the project and developed a high-level design to produce hydrogen which will be liquefied and exported from Gladstone to Asia. It also defined the likely preferred development approaches, established project lifecycle cost estimates, and undertook a risk analysis. The Concept Study was completed in September 2020.

Key findings from the Concept Study included:

- Demand for green hydrogen and green ammonia is particularly strong in Asia, specifically in Japan, Korea and Singapore;
- There is potential for green hydrogen to be produced in Central Queensland at a scale to meet offtake requirements, leveraging the competitive advantages of the region (renewable energy and water resources, port infrastructure, industrial land, and proximity to export markets);
- The ability to meet offtaker pricing requires significant cost reductions in line with targets put forward by governments and companies globally.

Stanwell spent $3.65 million on the Demonstration Project Feasibility Study and scale-up Concept Study, with ARENA contributing 25 per cent ($914,000) to these costs.

[35] Stanwell Corporation Limited (Stanwell), Stanwell Hydrogen Project Feasibility Study (October 2020, available at: https://www.stanwell.com/energy-assets/new-energy-initiatives/stanwell-hydrogen-project/stanwell-hydrogen-project-3/ and https://arena.gov.au/knowledge-bank/stanwell-hydrogen-project-feasibility-study/)

Planning Phase

Based on the findings of the Concept Study, in October 2020, Stanwell and Iwatani decided to proceed with a Planning Phase to further develop the CQ-H_2 Project. In anticipation of the next stage in the Project, Stanwell and Iwatani formed a consortium in November 2020.

The key objectives of the Planning Phase were to:

- Form a Project consortium of companies with expertise across the supply chain.
- Develop a costed plan to progress the project to a Financial Investment Decision via a gated Feasibility Study/FEED process.
- Progress land and infrastructure arrangements including:
  - Secure ongoing access to production land through EDQ and progress port arrangements with Gladstone Ports Corporation;
  - Commence contractual arrangements to secure water supply and transmission access for the Project via Gladstone Area Water Board and Powerlink;
  - Run an Expression of Interest (EOI) process to identify potential renewable energy projects that could support the Project;
- Secure government funding and support from the Australian Government, Queensland Government and Government of Japan.

The Planning Phase was completed in August 2021 with all key objectives met.

Feasibility Study

In September 2021, Stanwell and Iwatani formed a broader Consortium with three leading Japanese companies (KHI, KEPCO, and Marubeni) and an Australian energy infrastructure business (APA) to undertake a detailed Feasibility Study into the CQ-H_2 Project. The Feasibility Study built on the learnings from the Concept Study. The Study commenced in September 2021 and was completed in June 2022.

1.4 Project objectives

Through the CQ-H_2 Project, the Consortium aims to achieve the following key objectives:

- Position Central Queensland as a preferred Australian renewable hydrogen hub by harnessing the region's renewable energy resources and high-quality infrastructure;
- Establish a first of its kind integrated hydrogen supply chain between Central Queensland and Japan;
- Achieve the target hydrogen pricing set by the offtakers, by deploying the supply chain at scale including production, liquefaction, and shipping of hydrogen;
- Improve the technology and commercial readiness of the Project by leveraging expertise across the supply chain and long-term partnerships with Japan's premier energy, gas, trading, and technology companies;
- Support Australian industry on the pathway to net zero carbon emissions through domestic supply of renewable hydrogen to major industrial users in Gladstone;
- Contribute to Australian, Queensland and Japanese Government ambitions for the hydrogen industry;
- Deliver significant economic and social benefits through employment and local business opportunities;
- Help the Consortium partners transition to a lower carbon future.

1.5 Consortium overview

The Consortium

The Consortium has strong primary technical expertise across the hydrogen supply chain as noted in the diagram below (note Consortium partners have an interest in investing in multiple parts of the supply chain).

Figure 8: Consortium Supply Chain Capabilities

Stanwell Corporation Limited

Stanwell is a Queensland GOC, lead sponsor of the Project, and a major provider of electricity to Queensland, the NEM, and large energy customers along the eastern seaboard of Australia. As one of Queensland's largest generators, Stanwell has a record of strong operational and financial performance.

With Stanwell's government ownership structure, it is in a strong position to leverage existing relationships with its Shareholding Ministers, Queensland Government agencies and local councils to develop sustainable long-term support for the Project. Government ownership of Stanwell also imbues an added level of credibility in developing new relationships with potential suppliers and offtake partners to enable the commercialisation of the Project.

Stanwell has formed a consortium with four leading Japanese companies and an Australian gas infrastructure business (APA) to establish a hydrogen export supply chain in Central Queensland. Stanwell is committed in-principle to participating in the CQ-H_2 Project as an investor, energy supplier and hydrogen producer.

As part of its portfolio renewal strategy, Stanwell has identified renewable hydrogen as a key target market for transforming its business to prosper in a lower carbon future. As an experienced energy company with a growing renewable energy portfolio and strong presence in Central Queensland, Stanwell is well-placed to facilitate the growth of the hydrogen industry.

Stanwell's vision is to see Central Queensland become a major hydrogen hub, creating economic opportunities for local communities and contributing to carbon emissions reduction for industry. Stanwell's vision and strategy demands a continued push to finding better ways of doing things so that Queensland can continue to enjoy reliable, affordable energy, with a lower carbon footprint.

Stanwell has several competitive advantages in pursuing the green hydrogen export opportunity including expertise as an energy provider, its status as a GOC (which has created credibility and trust with offtakers) and established relationships with potential offtakers. Stanwell is targeting a role in the Project as an owner/operator of hydrogen plant and energy and water manager. Stanwell's ultimate role will be subject to Board and Shareholder approval. The Board has a strong commitment to pursuing the stated hydrogen opportunities and will play a key role in supporting the Project from feasibility through to execution.

Stanwell currently owns and operates a diversified energy portfolio including resources related to power generation, retail electricity and commodity trading functions. Stanwell's portfolio includes 3,341 MW of traditional energy generation assets located throughout Queensland. Stanwell owns and operates Stanwell Power Station near Rockhampton, the Tarong power stations and Meandu Mine near Kingaroy.

Stanwell has a history of high asset performance through the application of innovative technology and engineering excellence. These innovations have been recognised both nationally and internationally, with Stanwell Power Station currently holding the world record of 1,087 days of continuous operation for the power station's Unit 1. Stanwell's engineering and energy trading skills are highly applicable to the renewable hydrogen industry which will require extensive capabilities in Stanwell's areas of technical expertise.

Stanwell and its predecessor companies have a strong track record of successful commercial ventures with Japanese companies. Notably, Tarong Energy entered a 50/50 joint venture with Tokyo Electric Power Company and Mitsui & Co to construct and operate the 443 MW Tarong North Power Station, which was commissioned in 2003. Stanwell's Tarong and Stanwell Power Stations were among the first plants in Australia to be supplied by Japanese boiler and turbine manufacturers (Hitachi).

During 2020-21, Stanwell invested more than A$235 million in capital projects at its sites across Queensland to improve efficiency or maintain asset performance, ensuring that both its assets and operational capabilities can respond effectively to market needs. A major milestone was reached in the establishment of a large-scale hydrogen industry in Central Queensland with Stanwell securing land for its proposed 3,000 MW renewable hydrogen electrolysis facility at Aldoga, 20 kilometres west of Gladstone. Stanwell have also entered into a long-term 346.5 MW offtake agreement with Clarke Creek Wind Farm to provide clean, renewable energy to its customers and help decarbonise its portfolio.

Stanwell has previously led the development of major Queensland infrastructure projects including Stanwell Power Station in the 1990s, and wind farms in both Queensland and interstate in the 2000s (Windy Hill and Emu Downs). During 2017-18, 2018-19 and 2019-20 Stanwell undertook major feasibility studies that generated significant technological and commercial learnings in relation to renewable energy technologies including:

- Clarke Creek Wind Farm – completion of due diligence, business case and execution of a 346.5 MW Power Purchase Agreement, to commence operations in 2024;
- Renewable energy development pipeline – Stanwell has over 2,000 MW of wind and solar projects in its development pipeline. These projects will be progressively brought online to provide renewable energy for hydrogen and Stanwell's retail business;
- Stanwell Hydrogen Demonstration Project – completion of a successful pre-feasibility study and Feasibility Study, including a scale-up concept study (funded by ARENA);
- North West Queensland Hybrid Power Plant. Joint Development Agreement with Vast Solar, Feasibility Study completed;
- Energy storage – Stanwell is developing 300 MW of battery storage projects across two sites – southern and central Renewable Energy Zones. These projects are at the FEED stage.

Iwatani Corporation

Iwatani is a leading Japanese trading company with a market capitalisation of 35 billion Yen. The company specialises in energy and gas services for industrial and household users in Japan and currently supplies liquid petroleum gas to 3.2 million households across Japan. Iwatani also has interests in consumer products, industrial materials, minerals, construction, agriculture, food and medical products.

Iwatani initiated operations at Japan's first commercial liquefied hydrogen plant in 1978, constructed the first liquid hydrogen plant in Osaka in 2006 and has since built a comprehensive nationwide hydrogen network ranging from production to transport, storage, supply, and security. Iwatani is currently Japan's only fully integrated supplier of hydrogen, catering to 70 per cent of the local hydrogen market. Iwatani has an annual production capacity of 120 million m^3 across three bases, six plants and ten compressed hydrogen plants which supply its base of 26 light and heavy-duty hydrogen re-fuelling stations as well as industrial customers in Japan.

In addition to being a strategic partner of the Project in Queensland, Iwatani is also involved in other hydrogen projects in Australia and globally. A list of Iwatani's hydrogen project initiatives is provided below:

- Iwatani is a strategic partner in the Hydrogen Energy Supply Chain (HESC) project in Victoria, which is expected to export ~ 225,000 tonnes of liquid hydrogen annually to Japan. Iwatani's focus on the HESC project is the handling and retail of liquefied hydrogen. KHI and Iwatani are leading the liquefaction build component at the Port of Hastings;
- Iwatani has recently signed an MOU with Fortescue Metals Group Ltd and KHI to investigate the production of liquid hydrogen from renewable energy in Australia and overseas for import into Japan;
- Iwatani is actively developing new hydrogen re-fuelling stations in Japan and other global markets with the aim of stimulating new hydrogen demand and supporting the widespread distribution of fuel cell electric vehicles. In November 2020, Iwatani America announced its plans to significantly expand the hydrogen fuelling station capacity by nearly 25 per cent in Southern California jointly with Toyota;
- Iwatani is a steering member of the Hydrogen Council, a global initiative of leading energy, transport and industry companies with long-term ambitions for hydrogen to foster the energy transition;
- Iwatani is a partner in the Fukushima Hydrogen Energy Research Field (FH2R) project, a 10 MW large-scale hydrogen energy system in Namie-cho, Fukushima Prefecture that will produce hydrogen annually using renewable energy. Project partners include NEDO, Toshiba, and Tuhoku Electric Power. Iwatani's role is managing hydrogen demand and supply forecast system, transportation, and storage of hydrogen;
- Iwatani is a member of the Hydrogen Utilization Study Group in Chubu wherein ten private Japanese companies are working together to promote hydrogen and create demand for hydrogen to build a supply chain for stable hydrogen utilisation in the Chubu region;
- Iwatani is a lead in the Kobe/Kansai Hydrogen Utilization Council, that was established by a group of 11 Japanese companies to promote a hydrogen supply chain in the Kobe/Kansai area;
- Iwatani is a member of Hydrogen Energy Supply-chain Technology Research Association ('Hystra') which was established to demonstrate a carbon free hydrogen supply chain comprised of hydrogen production effectively utilising brown coal, transportation, storage and utilisation of hydrogen, to commercialise the supply chain around 2030.

Marubeni Corporation

Marubeni is a global Japanese integrated trading and investment conglomerate with products and services spread across a broad range of sectors including LNG, power projects and infrastructure, industrial machinery, finance, logistics, real estate development and construction. It is the fifth-largest general trading company in Japan and has a leading market share in cereal and paper pulp trading as well as a strong energy and industrial machinery business.

Marubeni has demonstrated a clear interest in investing in the hydrogen industry in Australia and globally through the following initiatives:

- Participation as a consortium member in Hydrogen Energy Supply Chain (HESC) Pilot Project in 2018. Marubeni's role in HESC relates to trading the new commodity and infrastructure investment;
- Agreement in 2020 with Australian LNG producer, Woodside Energy, and Japanese organisations, JERA and IHI Corporation, to participate in a feasibility study to examine the

potential of export and storage of ammonia for use in ammonia co-firing in thermal power plants in Japan;

- Proof of concept for the production of economical green hydrogen in South Australia, transportation of hydrogen by metal hydride in Indonesia and utilisation of hydrogen through fuel cell in industrial town in Indonesia.
- Marubeni is involved in various hydrogen projects in Japan and other countries which include:
- Lead in the Kobe/Kansai Hydrogen Utilization Council, that was established by a group of 11 Japanese companies to promote a hydrogen supply chain in the Kobe/Kansai area and draw a pathway to realise large-scale commercialisation of hydrogen utilisation by 2030;
- MOU with the Abu Dhabi Department of Energy to collaborate in establishing a hydrogen-based society and to pursue the efficient use of water and electricity in Abu Dhabi, use of renewable energy for hydrogen production, and develop supply and distribution concepts;
- Member of Hydrogen Energy Supply-chain Technology Research Association (‘Hystra’);
- Agreement in 2021 with Oman’s energy company OQ SAOC, a global industrial gas company Linde plc and UAE’s engineering company Dutco Group for conducting a technical and commercial feasibility study on the development of a green hydrogen & green ammonia production infrastructure in the Salalah Free Zone in Oman;
- MOU with Scottish Enterprise on comprehensive collaboration for the decarbonisation of Scotland including floating offshore wind and green hydrogen businesses in Scotland.

Kansai Electric Power Company Incorporated

KEPCO is an electric utility within the operational area of Kansai region and distributes electricity to Osaka and the surrounding Kansai area. KEPCO is the second-largest electric power company in Japan and generates electricity from hydroelectric, thermal, geothermal, and nuclear power sources. The company also engages in the business of transportation, heat supply, telecommunications, real estate, and gas supply services.

In February 2021, KEPCO announced its Zero Carbon Vision 2050 which envisions three key pillars to achieve its goal of carbon neutrality by 2050:

- Zero-carbon emissions on the demand side;
- Zero-carbon emissions on the supply side; and
- Seeking to create a hydrogen-based society.

KEPCO’s Zero Carbon Vision 2050 emphasises the importance of accelerating the adoption of new technologies, including hydrogen, ammonia, and Carbon Capture Utilisation and Storage (CCUS) which mainly focuses on carbon-recycling technologies.

KEPCO has embarked on various initiatives to align with its 2050 carbon neutral goals. KEPCO has signed an agreement with RWE Renewables to jointly study the feasibility of a large-scale floating offshore wind project off the Japanese coast in August 2021. KEPCO has initiated a pilot study on distributed energy management with its business customers, combining onsite solar PV generation and energy storage through batteries since June 2021.

KEPCO’s current involvement in the hydrogen sector includes:

- KEPCO has steadily undertaken initiatives to get ready for building the future hydrogen-driven society including hydrogen production and its domestic supply through Hydro Edge Co., Ltd., a joint venture with Iwatani Corporation and Sakai LNG Co., Inc., and has been implementing feasibility studies on co-firing hydrogen at thermal power plants;
- KEPCO along with Iwatani, shipbuilder Namura Shipbuilding and other partners are working on a feasibility study to develop a vessel powered by hydrogen fuel cells and have plans to develop a fuelling station to supply hydrogen to the vessel. The group is aiming to operate the hydrogen fuel cell vessel during the Osaka-Kansai Japan Expo in 2025;

- KEPCO is a part of the Kobe/Kansai Hydrogen Utilization Council that has built a roadmap for implementation of the hydrogen utilisation business models in the Kansai area through a combined study from supply and demand sides to develop large-scale hydrogen supply chain;
- KEPCO is a member of the Japan Hydrogen association (JH2A) to promote the formation of a hydrogen supply chain and global partnerships in the hydrogen sector.

Kawasaki Heavy Industries Limited

KHI, together with approximately 100 group companies in Japan and overseas, forms a "technology corporate group" that has technological capabilities in delivering products into fields ranging beyond air, land and sea, and extending from the depths of the ocean to space. The company operates across a wide variety of areas, with aerospace, rolling stock, ship and offshore structure, and energy solutions divisions. The ship and offshore structure division includes gas carriers, large tankers, and submarines, whilst the energy solutions division covers a spectrum of products from the development and manufacturing of energy equipment through to management systems. KHI's ship & offshore structure business division includes LNG carriers, liquefied petroleum gas (LPG) carriers, bulk carriers, container ships, submarines and governmental ships, oil tankers, and car carriers & roll-on/roll-off (RO / RO) ships. KHI is also active in numerous other areas including environmental and recycling plants, industrial plants, industrial robots, precision machinery, and infrastructure equipment, along with operating a leisure and power products business, featuring the Kawasaki brand of motorcycles.

KHI is a world leader in the production, storage, shipping and handling of liquid hydrogen. Since 2010, Kawasaki has backed the building of a hydrogen energy supply chain, using its history and expertise of the technology in the fields of extremely low temperatures for LNG ships, plant engineering and gas turbines. In December 2019, Kawasaki launched the Suiso Frontier, the world's first liquefied hydrogen carrier. KHI's involvement in the hydrogen industry is summarised below:

- KHI is a key project partner and shipbuilder in the Hydrogen Energy Supply Chain (HESC) Victoria project. The ship is expected to play a key role in realising the HESC project's world-first demonstration of a hydrogen supply chain between Australia and Japan;
- KHI completed the Kobe LH2 terminal "Hy touch Kobe" on Kobe Airport Island, Japan which is a receiving terminal as part of international hydrogen energy supply chain (HESC) project;
- Origin Energy and KHI are collaborating to assess the potential of a green hydrogen production facility in Townsville, with an initial scale of 36,000 tpa hydrogen production for export and domestic supply. A feasibility study was completed in 2020;
- KHI entered into a MOU with Fortescue Metals Group Limited and Iwatani to develop a business model for the supply of liquid hydrogen from Australia into Japan;
- KHI is a member of the Hydrogen Council, a global initiative of leading energy, transport and industry companies;
- KHI developed Japan's first industrial-scale hydrogen liquefaction system, which is currently installed in the Hydrogen Technology Demonstration Center at Harima Works and has the capacity to liquefy five tonnes of hydrogen per day. The system was built upon Kawasaki's technology of handling cryogenic materials and turbines;
- KHI is building solutions for liquefied hydrogen land transport and storage which includes LH2 containers, storage tanks, compressed gaseous hydrogen trailers.

APA Group

APA is a leading Australian energy infrastructure business, listed on the Australian Securities Exchange (ASX), that owns and/or operates a $21 billion portfolio of gas, electricity, solar and wind assets around Australia.

Consistent with APA's purpose to strengthen communities through responsible energy, APA delivers approximately half of the nation's gas usage and connect Victoria with South Australia and New South Wales with Queensland through its investments in electricity transmission assets. APA is also one of the largest owners and operators of renewable power generation assets in Australia, with wind and solar projects across the country.

APA's 15,000 kilometres of natural gas pipelines connect sources of supply and markets across mainland Australia, and its 7,500-kilometre East Coast Grid of interconnected gas transmission pipelines provides the flexibility to move gas around eastern Australia, anywhere from Otway and Longford in the south, to Moomba in the west and Mount Isa and Gladstone in the north. APA's services include:

- *Gas transmission:* APA offer natural gas producers, users and retailers the flexibility to seamlessly move volumes of gas to where it's needed, through high-pressure gas transmission pipelines and interconnected grids, spanning mainland Australia;
- *Gas distribution:* APA manage and operate local distribution networks that deliver gas to around 1.4 million households and businesses in South Australia, Victoria, Queensland, country New South Wales and the Northern Territory;
- *Asset management:* APA provide asset management and operational services for most of its energy assets and investments, as well as to third parties;
- *Other energy services:* APA is also helping to connect Australia to its energy future through investing in and operating assets including gas-fired power stations, electricity transmission interconnectors, and renewable generation such as solar farms and wind farms.

Within Queensland, the 7,500-kilometre East Coast Grid includes (amongst others):

- Berwyndale Wallumbilla Pipeline (BWP);
- Carpentaria Gas Pipeline (CGP);
- Reedy Creek Wallumbilla Pipeline (RCWP);
- Roma Brisbane Pipeline (RBP);
- South West Queensland Pipeline (SWQP);
- Moomba Sydney Pipeline (MSP);
- Wallumbilla Gladstone Pipeline (WGP).

In May 2022 APA announced it will commence the second stage of its 25 per cent expansion of its East Coast Gas Grid, which will add around 13 per cent of capacity for southern states through additional compression and associated works on both the South West Queensland Pipeline (SWQP) and Moomba Sydney Pipeline (MSP). This second stage is part of APA's East Coast Grid pipeline network expansion announced in May 2021, which will add a total of 25 per cent capacity at a total capital investment of around $270 million.

As the energy transition accelerates, APA is well placed to diversify and deploy decades of knowledge and capability to play a leading role in developing the low emissions technologies of tomorrow, at scale, and to support a net zero future. In 2021 APA announced its ambition for net zero operations emissions by 2050 and continues to invest in new capability to support sustainability and climate change risk management.

And in early 2021, APA also launched its Pathfinder Program – a new initiative that will help unlock energy solutions of the future with an initial focus on clean molecules, storage and micro grid solutions, supporting pilot projects, equity investments and research and development.

1.5.1 Roles and responsibilities

Table 16: Summary of Feasibility Study roles

Company	Feasibility Study role
Stanwell	• Australian study lead • Energy, electrolysis lead • Project development lead (infrastructure, planning, approvals)
Iwatani	• Japan consortium and study lead • Liquefaction integration lead • Electrolysis support
KEPCO	• Advice on end user markets, timing, volumes, pricing, utilisation of hydrogen
Marubeni	• Advice on study approach • Information gathering through local networks • Information on Japanese off-takers
KHI	• Schedule for liquefaction facilities, storage tank, liquefied hydrogen carriers • Information on equipment specifications and costs
APA	• Pipeline lead • Advice on study approach • Information gathering through local networks • Information on infrastructure specifications and costs

1.5.2 Involvement of ARENA, METI and other government agencies

Australian Government and government agencies & corporations

Australian and Queensland Governments (including GOCs)

The Consortium has established highly effective working relationships with all levels of government and with key government agencies.

Australian Renewable Energy Agency

ARENA's purpose is to accelerate Australia's shift to affordable and reliable renewable energy by providing financial assistance to support innovation and the commercialisation of renewable energy and enabling technologies to help overcome technical and commercial barriers. Renewable hydrogen is a key investment priority for ARENA and to date ARENA has committed over A$160 million to renewable hydrogen projects including research and development, feasibility studies and demonstration projects. As part of ARENA's Investment Priorities, it will continue to support high merit studies, trials and deployment projects that accelerate the commercialisation of renewable hydrogen in Australia.

The CQ-H_2 Project will also be eligible to apply for ARENA grant funding towards the cost of the FEED study and towards the capital cost of the Project.

Coordinator-General

Within the Gladstone SDA, the Queensland Coordinator-General (an officer of the Queensland Government) is responsible for regulating development in accordance with a development scheme which provides an efficient process for assessing applications and requests. Within the development scheme the Coordinator-General can decide whether the referral, public consultation and review stages do not apply, allowing for timely decision making.

Decisions made by the Coordinator-General under the development scheme are final and not subject to a merits-based review process.

The Coordinator-General is engaging with relevant State agencies and port authorities to ensure that land use and provision of infrastructure is planned for and can be delivered in a coordinated way – to maximise the potential economic benefits for the emerging hydrogen industry.

The Coordinator-General's ability to access land and facilitate multi-user corridors provides an opportunity to help facilitate renewable hydrogen industry development and streamline requirements for investors to source suitable land for infrastructure. The Coordinator-General has an established process in place to facilitate upgrades or changes to port, roads and rail.

Economic Development Queensland

EDQ is a Queensland Government agency delivering property development and specialist land use planning and infrastructure functions. EDQ supports development projects in regional and urban areas and works with local governments, industry, and the community to add value to development projects and create investment opportunities.

EDQ drives a range of development projects including:

- large complex urban sites which support renewal;
- regional residential projects which respond to community need;
- industrial projects which generate on-going employment opportunities; and
- infrastructure projects which encourage further development.

State development areas (SDAs) are clearly defined areas of land established by the Coordinator-General to promote economic development in Queensland. Declared in 1993, the GSDA, located north-west of Gladstone, is a defined area of land dedicated for industrial development and materials transportation infrastructure. A significant portion of land within the GSDA is owned by the state government with the Minister for Economic Development Queensland (EDQ) owning 11,054 hectares. The Stanwell hydrogen production site at Aldoga falls within the GSDA and is owned by the Minister for EDQ.

Japanese Government and government agencies

Ministry of Economy, Trade and Industry

Japan's METI has been transforming itself to respond to the needs of the times and has a history of responding to the changing needs of society. Its history is the history of Japan's progress.

In 1949, the Ministry of Commerce and Industry was reorganised, and the Ministry of International Trade and Industry (MITI) was established. In 2001, MITI was reorganised to the METI (reorganisation of government ministries into 1 cabinet and 12 ministries). METI was established by the *Act for Establishment of the Ministry of Economy, Trade and Industry*.

METI's mission is to develop Japan's economy and industry by focusing on promoting economic vitality in private companies and smoothly advancing external economic relationships, and to secure stable and efficient supply of energy and mineral resources.

METI has confirmed that this project is necessary to strengthen the relationship between Japan and Australia, with METI making a ~$500,000 contribution to the Japanese Consortium partners' Feasibility Study labour costs. The Japanese leader of the Project, Iwatani, reports monthly to METI on project progress, and coordinates grant applications. METI has also participated in the Steering Committee and has contributed to building relations between the two countries. METI understands that this project is a realistic green hydrogen project. This is because there are significant renewable energy sources in the vicinity of the proposed CQ-H_2 site and the Project is expected to generate demand locally as well as in Japan. METI are also very interested in the hydrogen movement that is taking place throughout Gladstone region.

1.6 Project schedule

The CQ-H_2 Project is focused on achieving the completion of Phase 1 in 2026 (commercial production commencing in Q1 2027), with Phase 2 coming online in 2031. Overall, the Project stages include:

- **Project Feasibility Study** (Sep 2021 – June 2022 [Complete]): increase engineering design definition and cost accuracy to Class 4 (±30%) and firm up offtake and joint venture arrangements;
- **Front-End Engineering Design (FEED)** (July 2022 to Q2 2023): further design definition and cost accuracy (Class 3 (±20%)), planning approvals and binding commercial arrangements;
- **Final Investment Decision (FID)** (Q3 2023);
- **Detailed design, construction, commissioning** (Q3 2023 – Q4 2026);
- **Commercial production** (Q1 2027).

The Project schedule is also outlined in the figure below.

Figure 9: CQ-H_2 Project Schedule

1.7 Regional overview

Gladstone region

Gladstone provides the ideal location for developing a liquefied hydrogen export project. Gladstone has suitable land and established infrastructure required to support development of renewable hydrogen projects. Gladstone has an excellent track record for industrial development and is perfectly positioned for locating Australia's first hydrogen ecosystem.

Gladstone already boasts extensive utility, road, rail and port infrastructure servicing its existing manufacturing, petroleum and gas, mining and heavy industry businesses. The GSDA has land dedicated for industrial development and materials transportation infrastructure as well as access to reliable power and a skilled workforce.

Gladstone is also rapidly developing the hydrogen supply chain that will be necessary to support large-scale hydrogen production and export projects. For example, Fortescue Future Industries (FFI) recently announced its Global Green Energy Manufacturing Centre manufacturing up to two gigawatts of electrolysers annually, will be built in Aldoga (approximately 5 kilometres from the HPF).

The Gladstone region is well setup as an industrial ecosystem. A multifunctional (government, industry, academia and community) alliance, known as the CQH2 Alliance[36], has been established. This alliance is focused on supporting the development of hydrogen related industries in the region. Stanwell and Iwatani are members of the CQH2 Alliance.

Stanwell has led an application from the Gladstone region and the CQH2 Alliance partners for funding from the Australian Government's Clean Hydrogen Industrial Hubs program. The basis of this application includes common user infrastructure that will support hydrogen supply chains. Specifically, this would mean government funding of a common user hydrogen pipeline and water infrastructure that will support the CQ-H_2 Project requirements and help to reduce overall capital requirements.

Gladstone is the industrial heart of Queensland, and well placed to support the Consortium's Project and its ambition for future expansion to large-scale renewable hydrogen production and export.

The region has a history of international trade and industrial development at significant scale, confirming the region as a strategic investment location for renewable hydrogen. There is vast industrial expertise in Gladstone, with experience in energy generation, mineral processing, metal manufacturing and fabrication and material handling.

The Gladstone Regional Council's (GRC) *2022 Strategic Priorities* report[37] identifies "Renewable Energy & the Transitioning Economy" as a key focus and opportunity for the region.

The report provides information on the assets within the Gladstone region (natural and economic) that create a competitive advantage, including:

- A natural deep-water port, which is also one of the world's largest multi-commodity ports;
- Proximity to Central Queensland's natural resources and the Surat Basin;
- Industrial land within the GSDA and SPL that is in proximity to existing enabling infrastructure;
- Existing heavy industry in the region along with supporting infrastructure;
- Robust supply chains that support industry, as well as a workforce that is highly skilled;
- Construction capacity (locally based) for delivery of major projects.

[36] Note: the CQH2 Alliance is distinct from the CQ-H2 Project and the associated Consortium

[37] *2022 Strategic Priorities,* Gladstone Regional Council (available at: https://www.gladstone.qld.gov.au/)

The report also provides detail on the economic profile of the region. Key statistics are outlined below:

- $5,349.450 million in Gross Regional Product (GRP);
- ~29,072 regional jobs;
- Constitutes 3.1 per cent of the economy of regional Queensland (in GRP terms) and 2.4 per cent (in local jobs terms);
- 2.9 per cent annual average growth rate of GRP;
- 63,861 residents, constituting 2.5 per cent of the total population of regional Queensland;
- Median age of 35 years (compared to regional Queensland's median age of 39 years);
- Forecast population growth to 75,327 in 2041;
- Average 566,000 visitors per annum to the region;
- 3,701 local businesses;
- Top four employers being:
    - 4,513 Manufacturing jobs – 15.5 per cent;
    - 3,251 Construction jobs – 11.2 per cent;
    - 2,821 Retail jobs – 9.7 per cent;
    - 2,510 Transport & Logistics jobs – 8.6 per cent.

Gladstone State Development Area

In addition to industrial expertise, the Queensland Government has dedicated and significant planning resources for Gladstone's continued industrial and economic development via the GSDA. A significant portion of land within the GSDA is owned by the State, and offers substantial benefits for large-scale industrial projects such as:

- access to the Port of Gladstone, Queensland's largest multi-commodity port, handling more than 30 different products;
- an established concentration of industrial development, minimising new project risks associated with environmental impacts, loss of amenity and transport conflicts;
- best practice land-use planning and management - ensuring land and infrastructure assets are, and remain, attractive to existing occupants and potential investors;
- more efficient use of land including the creation of a dedicated multi-user infrastructure corridor for linear materials transport;
- the Coordinator-General's ability to provide greater certainty to industry regarding planning and approval processes, safeguard land from inappropriate and inconsistent land uses, coordinate and communicate with private landholders and facilitate access and tenure for proponents.

Port of Gladstone

The Queensland Government maintains ownership of commercial businesses in energy, water, rail and ports in the Gladstone region. This allows the Queensland Government to have strategic influence over the commercial planning and priorities of these entities.

The Port of Gladstone is Queensland's largest multi-commodity port. Managed by GPC, the world class port handles more than 30 products, which are then transported to more than 30 countries.

With a naturally deep-water harbour protected by islands, the Port of Gladstone has been identified as one of Queensland's priority ports.

Within the Port of Gladstone precinct, GPC is responsible for long-term strategic planning, land and infrastructure development approvals, state and federal environmental authorities and compliance, port and vessel safety, managing commercial contracts and pricing for port vessel and freight infrastructure and logistics, managing industrial properties, the marina and parklands.

In addition to world-leading coal, alumina, aluminium and LNG export facilities, and bauxite and industrial chemical import facilities, GPC provides a container and break-bulk service at the 129 ha Gladstone Port Central Facility.

The port has significant expansion capacity, with large landholdings, positioning Gladstone as one of Australia's expandable ports. Critical infrastructure, including channels and wharfs, remain Queensland Government owned and are managed through GPC.

GPC is currently preparing for hydrogen development through consideration of infrastructure optimisation, or the upgrades required, and the timelines involved.

Central Queensland Renewable Energy Zone

The CQ-H_2 Project is located in the Central Queensland Renewable Energy Zone (Central QREZ) – this zone is illustrated in Figure 10 below. The Central Queensland region is known to have good solar radiance and high-quality wind resources, which is supported by a strong transmission network to demand centres. The renewable energy resource potential is well in excess of that required Phase 1, as illustrated by the AEMO assessment of renewable resource potential – 3.5 GW wind and 7.7 GW solar[38].

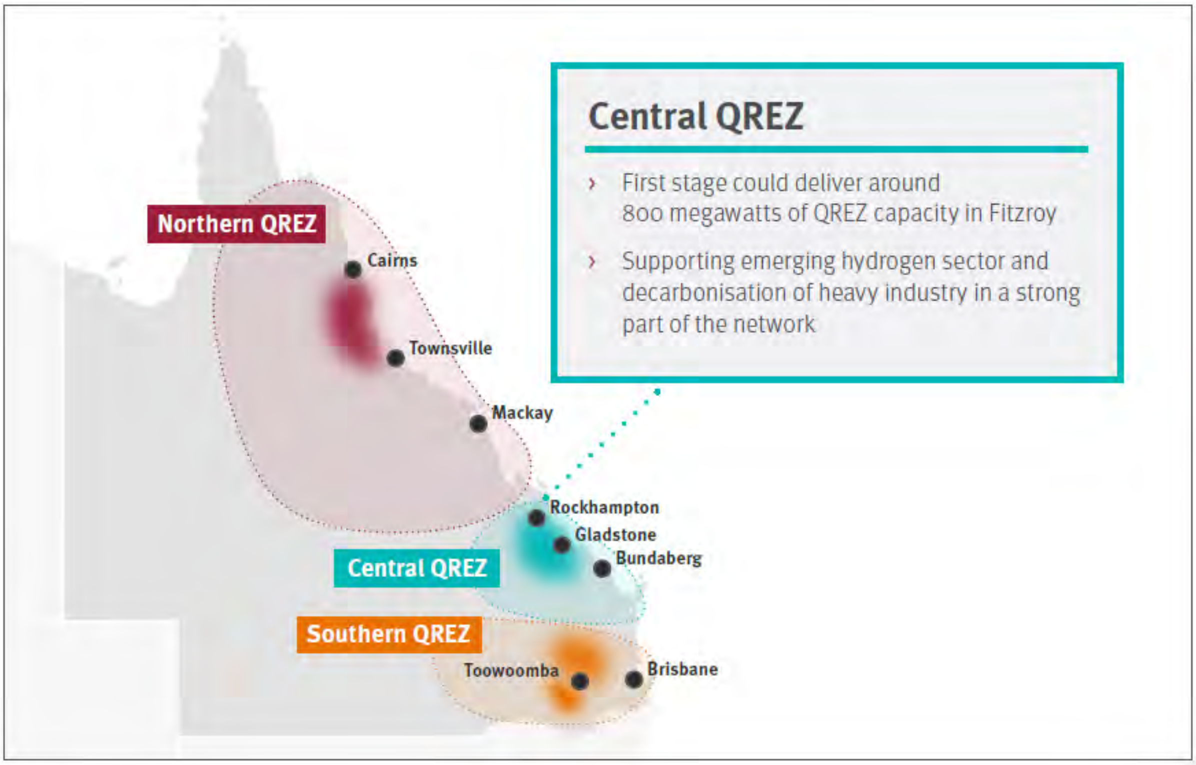
In August 2020, the Queensland Government committed A$145 million to establish three Queensland Renewable Energy Zone regions in northern, central and southern Queensland.

Construction of the Central QREZ will enable a coordinated approach to renewable assets ensuring the industrial decarbonisation and emerging hydrogen economy opportunity is matched to the region's renewable potential. With high industrial emissions in hard to abate sectors, Gladstone is particularly important in Queensland's transition to 50 per cent renewable energy by 2030 and net zero emissions by 2050. There will be high demand locally for hydrogen, providing an offtake opportunity as well as accelerating the state's zero emissions future.

As a first stage of development, the Central QREZ will be supported to host approximately 800 MW of renewables. Further detailed market-sounding and transmission planning is required to unlock this capacity in line with demand for clean energy, which is anticipated to grow significantly in this region. A registration of interest survey ran in September 2020 to determine the level of REZ investment interest, attracted 67 projects representing more than 23,000 MW in the Central QREZ region. Subsequent QREZ delivery stages have the potential to further build on this interest and deliver greater renewable capacity in the future, which will support Phase 2 of the CQ-H_2 Project.

[38] AEMO 2020 | 2020 Integrated System Plan

Figure 10: QREZ locations



1.8 Supply chain overview

A high-level overview of the proposed CQ-H_2 Project and Gladstone region is provided in Figure 11 below.

Figure 11: Proposed CQ-H_2 Project and Gladstone region

The CQ-H_2 Project will be developed in two phases:

Phase 1

The CQ-H_2 Project is targeting 100 tpd of gaseous hydrogen feed with first production commencing in December 2026, for delivery in early 2027. It is expected that the HLF will be located at Fishermans Landing, and the HPF will be located in Aldoga, 20 kilometres from the HLF. The HPF will have a variable production capacity, whilst the HLF is effectively continuous, hence hydrogen storage will be required.

Phase 2

The CQ-H_2 Project is targeting an additional 700 tpd of gaseous feed for the second phase of development (i.e., Phase 2), with expanded production commencing in 2031. The expanded HLF can be accommodated at Fishermans Landing. Phase 2 will see the expansion of the Phase 1 development at Aldoga.

The Project is to be located within the GSDA, with land owned by the Queensland Government and zoned for heavy industry development.

Broadly, the supply chain involves the following elements:

- **HPF** → raw water treatment, electrolysis, and hydrogen compression and storage;
- **Hydrogen pipeline** → transportation of gaseous hydrogen from the HPF to the HLF;
- **HLF** → liquefaction of gaseous hydrogen and storage of liquefied hydrogen;
- **Loading & Shipping**.

Access to utilities including renewable energy (solar power, wind power, grid power with greening via LGCs), raw water and wastewater disposal has also been scoped.

2 Feasibility Study approach

The CQ-H_2 Project Feasibility Study built on work previously undertaken including a Concept Study which examined the concept of establishing a commercial scale, green hydrogen electrolysis plant and liquefaction plant in Gladstone. This Concept Study was undertaken by Stanwell and Iwatani and was completed in November 2020.

This Feasibility Study has been delivered under a MOU which established a Consortium of six partners. The MOU identified the objectives of the study, set out the governance and cost sharing arrangements and identified Stanwell as the study lead.

The Feasibility Study was a collaborative effort, undertaken with the assistance of consortium members and advisors and in consultation with a number of external agencies and organisations.

The consultations included:

- Central Queensland Port Authority (Port of Gladstone);
- GAWB;
- Powerlink;
- DSDILGP;
- EDQ;
- OCG.

Advisory services were provided by:

- Advisian/Worley (technical advisory);
- Deloitte (commercial & financial advisory);
- Advisian (stakeholder and strategic advisory);
- MinterEllison (legal advisory).

The purpose of the Feasibility Study was to advance the understanding of the Project, relative to the Concept Study, and resolve potential fatal flaws, with the aim being to drive innovation and to establish an improved capital and operating cost estimate.

A structured approach was taken, with adaptive focus on areas with the greatest material impacts.

2.1 Feasibility Study objectives

The purpose of the Feasibility Study was to investigate the potential of a large-scale green hydrogen production facility near Gladstone, and a liquefaction plant at the Port of Gladstone.

Specifically, the Feasibility Study sought to achieve the following key objectives:

- Assess the commercial, technical and strategic viability of the Project;
- Identify a preferred reference project including scale, location, design, technology selection, cost estimates (Class 4) (with sufficient confidence and reliance) and development pathway for project phases;
- Secure offtake agreements for the hydrogen output of the project (which will become binding subject to successful completion of FEED);
- Complete the necessary project development steps to provide sufficient certainty to enter the FEED stage, including securing energy, land, water, port, and other infrastructure;
- Prepare a feasibility study report to support a decision from project partners on whether to proceed to the FEED stage.

2.2 Assessment framework

The Project's workflow was delivered under three workstreams in line with the objectives that were identified. The workstreams were delivered under the leadership of internal project personnel with significant input and support from external advisors.

The workstreams were technical, commercial, strategic and project management and the deliverables of each were as follows:

2.2.1 Technical

- Complete Class 4 (+/- 30%) design and cost estimates for the full project scope including renewable energy, water, electrolysis, hydrogen transportation, liquefaction, and shipping.
- Undertake Early Contractor Involvement (ECI) with Original Equipment Manufacturers (OEMs) to obtain more accurate costs and develop a shortlist of suppliers.
- Complete due diligence on the proposed production land and port site for liquefaction and shipping and prepare contracts for sale/lease.
- Develop supply approach for power and water, including submitting connection applications to Powerlink and GAWB.
- Develop detailed planning and regulatory approvals pathway.
- Complete environmental and social assessments (land, aquatic, marine ecology, air quality, noise impacts, traffic, and corridor).

2.2.2 Commercial

- Confirm offtake/market arrangements and develop binding term sheets to support progression to FEED.
- Complete project financial modelling.
- Complete market sounding for renewable energy and conclude non-binding term sheets with renewable energy projects (~1000MW).
- Identify project partners and develop Joint Venture (JV) structure and documents to enable execution prior to entering FEED stage.
- Develop funding strategy including commencing Government funding processes.

2.2.3 Strategic

- Develop and implement stakeholder engagement strategy.
- Secure and maintain support from key stakeholder groups.
- Complete social impact assessment including cultural heritage and native title.
- Assess workforce/skills and local content/manufacturing requirements and opportunities.
- Secure Board, Shareholder and Government approval to move to FEED stage.
- Manage policy and regulatory issues.

2.2.4 Project management

- Complete project execution plan and schedule.
- Develop contracting strategy and pre-qualify and qualify suppliers.
- Complete Request for Proposals to identify participants for FEED competition.

- Complete safety and risk assessment.
- Plan for Integrated Project Management Team for FEED stage.

2.3 Risk and opportunity analysis, management and mitigation

The risk management process for the Project was undertaken in accordance with Stanwell's Risk Management Policy and Framework, which uses the principles of ISO:31000.

A specific risk management plan has been developed for the Feasibility Study to analyse risks and to evaluate opportunities.

The Project Risk Register and RMP is reviewed and refreshed as part of the Feasibility Study.

2.4 Key inputs

Key inputs were developed at the outset of the Feasibility Study to establish key parameters and assumptions in order to further advance the technical and commercial workstreams. The table below summarises the key inputs.

Table 17: Summary of Feasibility Study basis

Input	Phase 1	Phase 1+2 combined
Hydrogen source	Water electrolysis	Water electrolysis
First hydrogen date	1 January 2027	1 January 2031
Scale	100 tpd H_2 daily target	800 tpd H_2 daily target
Hydrogen environmental rating	Carbon neutral based on emission offsetting certificates	Carbon neutral based on emission offsetting certificates
Hydrogen quality	Purification for export (i.e. 99.999%)	Purification for export (i.e. 99.999%)
LH2 plant location	Fisherman's Landing	Fisherman's Landing
HLF inlet pressure	30 barg	30 barg
Carbon price	$0 / ton	$0 / ton
HPF grid connection node	Larcom Creek substation (275 kV)	Larcom Creek substation (275 kV)
Water supply philosophy	Surface water is acceptable	Surface water is acceptable
Electrolyser plant availability (Excl. planned shutdowns)	High i.e. 97-100%	High i.e. 97-100%
Metering and quality	GC based quality and HHV will be used as basis for sale	GC based quality and HHV will be used as basis for sale
Electrolyser Major Hazard Facility status	Notify as possible MHF to regulator	Yes
LH2 Major Hazard Facility status	Yes	Yes
Hydrogen ownership transfer location	At HLF Receiving facilities outlet	At HLF Receiving facilities outlet
HLF ultimate capacity (Maximum forward load rate excluding losses)	110 tpd	880 tpd
Market orientation	Export (to Asia)	Export (to Asia)

3 Identification of Reference Project

3.1 Reference Project – at commencement of Feasibility Study

The proposed Reference Project identified at the commencement of the Feasibility Study envisaged Stanwell and consortium partners delivering a Project which would be characterised by the following features:

- **Hydrogen production facility:** Construction of a HPF to be located at Aldoga (on land to be acquired from its current owner, EDQ);
- **Hydrogen electrolysis:** Production of gaseous hydrogen using electrolysis technology, using demineralised water and electricity for the water splitting. The Project was expected to use an alkaline electrolyser operated at a load factor of around 80 per cent for Phase 1;
- **Hydrogen storage:** Additional hydrogen storage, both in the form of storage tanks and pipeline storage to address the mismatch between the variable production capacity of the combined HPFs (HPF 1 and HPF 2) and the effectively continuous operation of the liquefaction facility. When renewable power generation availability falls below the minimum power requirement of the electrolysers, the hydrogen storage is drawn down. Some imported grid power may be required to maintain the supply of hydrogen;
- **Hydrogen transportation to liquefaction via pipeline:** A dedicated pipeline for delivery of hydrogen from the HPF to the HLF;
- **Hydrogen liquefaction facility:** A HLF located at Fisherman's Landing (an industrial zoned portion of land near Gladstone that has access to a deep-water port). The site has access to raw water, water disposal, electricity utilities and is suitable for the location of the proposed HLF;
- **Hydrogen liquefaction and shipping:** Liquefaction technology for production of liquefied hydrogen. The Phase 1 development is targeting 100 tpd of liquefied hydrogen, and Phase 2 is targeting 900 tpd;
- **Offtake:** Domestic and international offtake of hydrogen produced. The primary offtake would be to supply green hydrogen to international offtakers. This liquefied hydrogen would be transported by ship. There would be an opportunity to supply local hydrogen offtakers for various applications;
- **Infrastructure:** Stanwell would leverage the local availability of network infrastructure, industrial land and on-site demineralised water to minimise other operating costs associated with the Project;
- **Energy supply:** Renewable energy arrangements to green the Project by purchasing/generating renewable energy and LGCs from proposed suitable wind and solar farms equivalent to 100 per cent of the energy requirements of the Project;
- **Financing and funding:**
    - Equity contributions from the Consortium;
    - Potential grant funding – it was envisaged that grant funding would be sought to finance the Project;
    - Potential concessional debt funding.

3.2 Reference Project – to be advanced to FEED

The proposed Reference Project defined during the Feasibility Study involved Stanwell making an initial investment to complete the Project which would be characterised by the following features:

- **Hydrogen production facility:** A HPF located at Aldoga (on land to be acquired from EDQ);

- **Hydrogen electrolysis:** Electrolysis technology for production of gaseous hydrogen using demineralised water and electricity for the water splitting. The Project is exploring various options for electrolyser technology. The electrolyser is expected to operate at a load factor of between 83 and 87 per cent for Phase 1. The Feasibility Study revealed several viable electrolyser technology options, with a final decision not expected until FEED;
- **Hydrogen storage:** Additional hydrogen storage, in the form of storage tanks at the HPF (for gaseous hydrogen) and the HLF (for liquefied hydrogen) to address the mismatch between the variable production capacity of the combined HPFs (HPF Phase 1 and HPF Phase 2) and the effectively continuous operation of the liquefaction facility. When renewable power generation reduces and is below the minimum power requirement of the electrolyser, the hydrogen storage is drawn down on as well as some imported grid power to maintain the supply of hydrogen. Pipeline storage is no longer being considered for the Project;
- **Hydrogen transportation to liquefaction via pipeline:** A dedicated pipeline for delivery of hydrogen from the HPF to the HLF;
- **Hydrogen liquefaction facility:** A hydrogen liquefaction facility located at Fisherman's Landing (an industrial zoned portion of land near Gladstone that has access to a deep-water port). The site has the ability to access raw water, water disposal, and electricity utilities (construction works would be required to establish utility connections). New wharf facilities will be required;
- **Hydrogen liquefaction and shipping:** Liquefaction technology for production of liquefied hydrogen. Phase 1 development is targeting 100 tpd of liquefied hydrogen, and Phase 1+2 is targeting 800 tpd;
- **Offtake:** Domestic and international offtake of hydrogen produced. The primary offtake would involve supplying green hydrogen via ship to international offtakers, with excess being supplied to local offtakers for various applications;
- **Infrastructure:** Stanwell would leverage the local availability of network infrastructure, industrial land and on-site demineralised water to minimise other operating costs associated with the Project;
- **Energy supply:** Renewable energy arrangements to green the Project by purchasing/generating renewable energy and LGCs from proposed suitable wind and solar farms, through behind-the-meter and grid connections, equivalent to 100 per cent of the energy requirements of the Project.
- **Financing and funding:**
    - Equity contributions from the Consortium;
    - Potential grant funding;
    - Potential concessional debt funding.

4 Technical solution

The technical workstream under the Feasibility Study, in collaboration with Consortium partners, identified and assessed each element of the supply chain to determine and optimise the equipment and infrastructure requirements to meet the required production rate and volume of liquefied green hydrogen.

The technical solution was driven by the requirement to produce 100 tpd of green hydrogen for Phase 1, growing to 800 tpd in Phase 2. This approach required the end-to-end optimisation of the supply chain, including determining energy and water requirements, sizing of electrolysers for the HPF, the pipeline, and the HLF. The assessments included key focus areas such as site location and area considerations, utility considerations (power, water, wastewater), balance of plant, materials and buildings, compression and storage of hydrogen, vendor engagement and selection, transport and logistics, and cost considerations (both capital and operating). The primary objectives of the technical stream were to:

- Identify and explore key areas which could add value to the Project;
- Reduce risks through scenario development and execution of early mitigation efforts;
- Protect and enhance value through improved project definition;
- Identify and screen potential fatal flaws;
- Provide greater stakeholder confidence through higher level cost estimation.

The technical analysis and solution development section is supported by a series of technical analyses and assessments that provided the basis for this report.

Elements to be included in the development and assessment of the technical solution are identified in Table 18 below.

Table 18: Indicative average consumption parameters

Parameter	Phase 1 (Min | SDR | Max)	Phase 1+2 combined (Min | SDR | Max)
HLF feed rate[39] (tpd)	40 | 100 | 110	640 | 800 | 880
HPF target SDR[40] (tpd)	103	830
HPF electrolyser size – Rated (MW)	285	2100
HPF power demand – SOL (MW)	- | 210 | 290	- | 1,713 | 2,465
HPF water demand (ML/y)	600	4,800
HPF wastewater production (ML/y)	109	875
HLF power demand (MW)	- | 70 | 75	- | 560 | 600
HLF water demand (ML/y)	1,396	11,170*
HLF wastewater production (ML/y)	571	4,569*
HLF arrival pressure (barg)	17 | 28 | 33	17 | 30 | 33
HLF arrival temperature (°C)	-5 | 35-40 | 50	-5 | 35-40 | 50

**Potentially no change to Phase 1 through use of seawater exchange*

[39] HLF feed rate is the driver of the consumption parameters

[40] Stream-day rate

Land requirements are provided in Table 19 below:

Table 19: Project land requirements

Land Requirement	Phase 1 (ha)	Phase 1+2 (ha)
Aldoga Plot	23	121.5
HLF Plot	10	50

4.1 Power supply and load factor

Power supply management and electrolyser capacity optimisation was undertaken as part of the Feasibility Study.

It is crucial, for the success of the Project, that a reliable renewable power supply is established, and the optimal load factor is determined. Power supply and load factor assessment and considerations for Phase 1 and 2 are examined below. The Project is focused on producing and shipping liquefied green hydrogen. In light of this and the diurnal cyclical nature of renewable energy (wind and solar), a significant element of the Feasibility Study was the trade-off and optimisation of power supply, load factor, electrolyser sizing and transmission infrastructure.

To provide additional power when insufficient wind and solar resources are available, the Project will utilise LGCs. The 'greening' of grid power using LGCs is acceptable for meeting the Consortium's identified renewable energy definition.

The focus of the power supply optimisation in the Feasibility Study was to:

- Minimise the LCOH;
- Enable the technical solution to be responsive to grid power import prices; and
- Ensure continuous HLF load requirements were met.

Phase 1

The renewable energy supply approach for Phase 1 of the Project that was developed at Concept Study stage was advanced during the Feasibility Study.

The approach to HPF production variability was to adjust production rates to address the seasonal and daytime variability in grid power import prices. The ability to reduce HPF production rates (to eliminate grid import during the evening peak in prices) is a key factor in reducing overall power supply costs.

Arrangements relating to power supply have been progressed with wind and solar farm developers, with these being under-pinned by MOUs or draft power purchase agreements (PPAs). The approach to grid power support was also refined.

There are two connection types that will be used to provide power supply to the facilities:

- BTM connection:
    - Does not use the NEM network;
    - Avoids TUoS;
    - Wholly dependent upon the ability of the renewable energy provider to generate power.
- NEM connection:
    - Subject to system losses and TUoS;
    - Allows the use of LGCs to achieve green power;
    - Allows the utilisation of existing transmission assets and access easements;

- Allows the connected plant to supply grid services (such as load response and regulation);
- Increased supply reliability to support critical safety functions within the plant;
- In support of the Phase 1 development, approximately 1,320 MW of renewable energy is available via Stanwell's renewable energy portfolio.

In Central Queensland, there are several other renewable energy projects currently under development. These will have a total of 2 GW of additional renewable energy by 2025. Stanwell is exploring equity investments in some of these projects. These additional projects have the potential to improve the power pricing for Phase 1 of the CQ-H_2 Project.

An overview of the potential commercial arrangements and potential Commercial Operations Dates (COD) with power suppliers (that Stanwell is progressing to support CQ-H_2 energy requirements) is outlined in Table 20 below.

Table 20: Potential power supply arrangements

Supplier	MW	Connection	Status of agreement and other information
Solar Farm No 1	~350 MW	BTM	• Non-binding MOU executed • PPA terms to be agreed and executed by FID • Located approx. 3 km from HPF
Wind Farm No 1	~346.5 MW	NEM	• PPA executed December 2020 • Construction set to commence in 2022 • Located approximately 200 km north-west of HPF
Wind Farm No 2	~310 MW	NEM	• Non-binding MOU executed • Next step is development of PPA Term sheet (to be executed mid-2022) •
Wind Farm No 3	313 MW	NEM	• Non-binding MOU executed • Next step is development of PPA Term sheet (to be executed mid-2022) •
Additional backup projects			
Solar Farm No 2	49 MW	NEM	• PPA executed • COD scheduled to commence in 2023
Wind Farm No 4	150 MW	NEM	• PPA terms agreed between the parties, final execution of the agreement due mid-2022 •
Wind Farm No 5	252 MW	NEM	• PPA terms under development, final execution due mid-2022 •

As Stanwell is exploring additional renewable energy projects within its portfolio, the additional back-up projects can be utilised if required to meet the renewable energy requirements for Phase 1 of the Project.

The analysis of key electricity cost trends enabled the optimum HPF load factor to be defined. The HPF Load Factor Assessment determined that the preferred load factor is defined by the BTM solar connection and grid interplay alone. Electrolyser demand is counter to the prevailing spot price i.e., maximum consumption when prices are low and minimum consumption when prices are high.

Both wind and solar power production experience seasonal variation, and wind experiences high degrees of inter-day variation. Grid power could be used to balance daily production. Figure 12 below illustrates the stream-day average power production profile of a combination of wind and solar power over a one-year period. The periodic nature of wind production is visible and characterised by periods of low and high production. The solar power profile shows distinct seasonal variation.

Figure 12: Power supply profile for a synthetic year

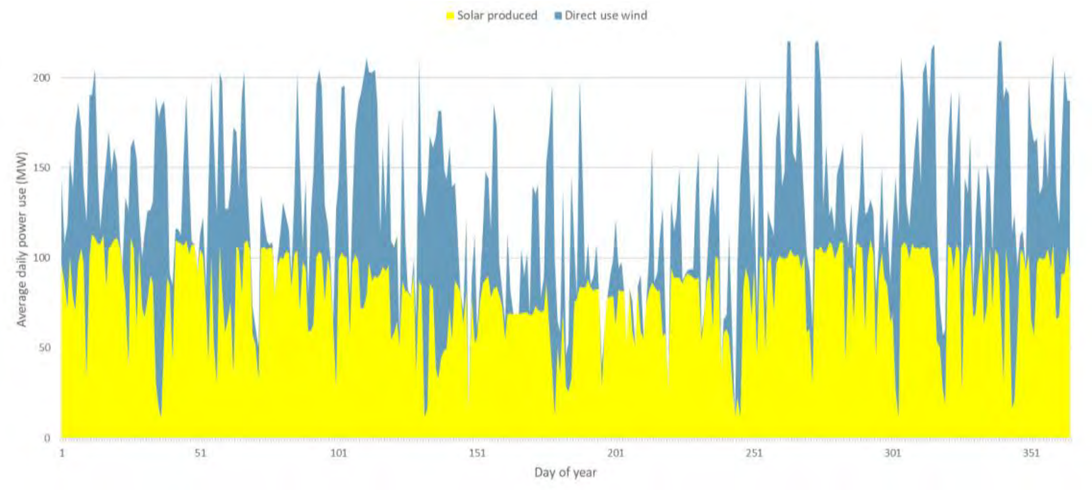
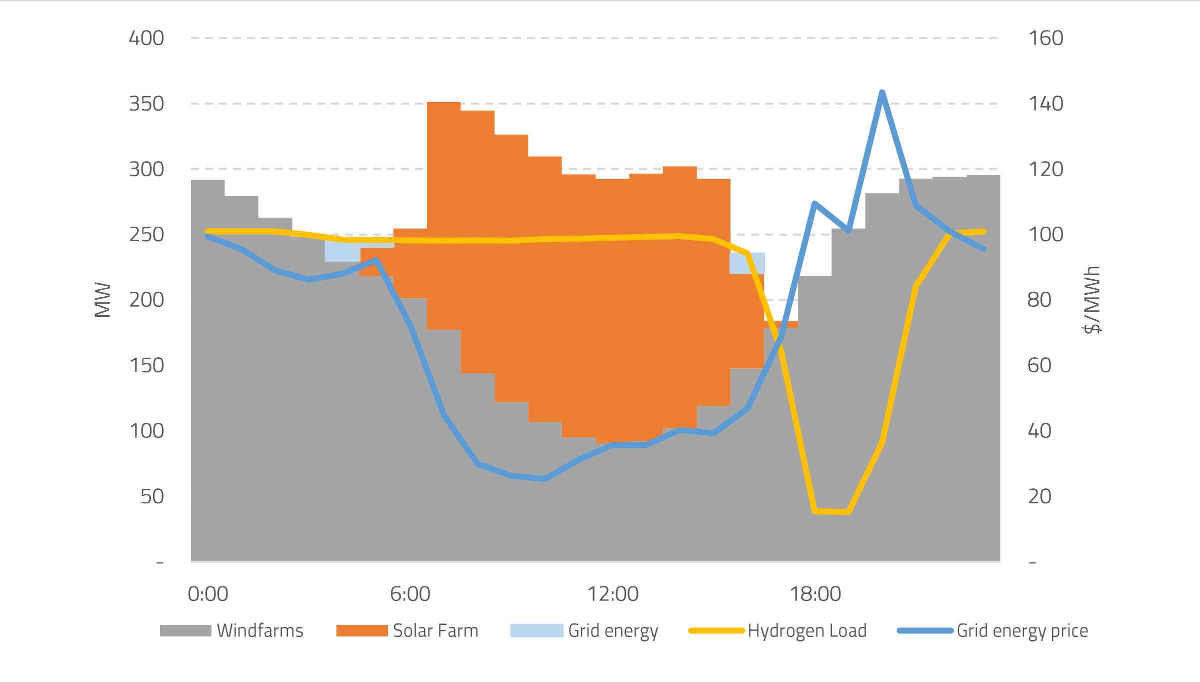


Figure 13 represents the supply profile and daily power demand for Phase 1 averaged over a 12-month period. A key consideration in the design of the HPF and electrolysers is the variable nature of renewable energy. During the daytime, supply of renewable power is plentiful and feed-in to the grid is unattractive (due to low cost of power), so HPF/HLF production is maximised. In the evening, the availability of renewable power is reduced and cost of power from the grid reaches a maximum. Hence, HPF production rate is greatly reduced in response to pricing/availability pressures.

Figure 13: Phase 1 average power profile

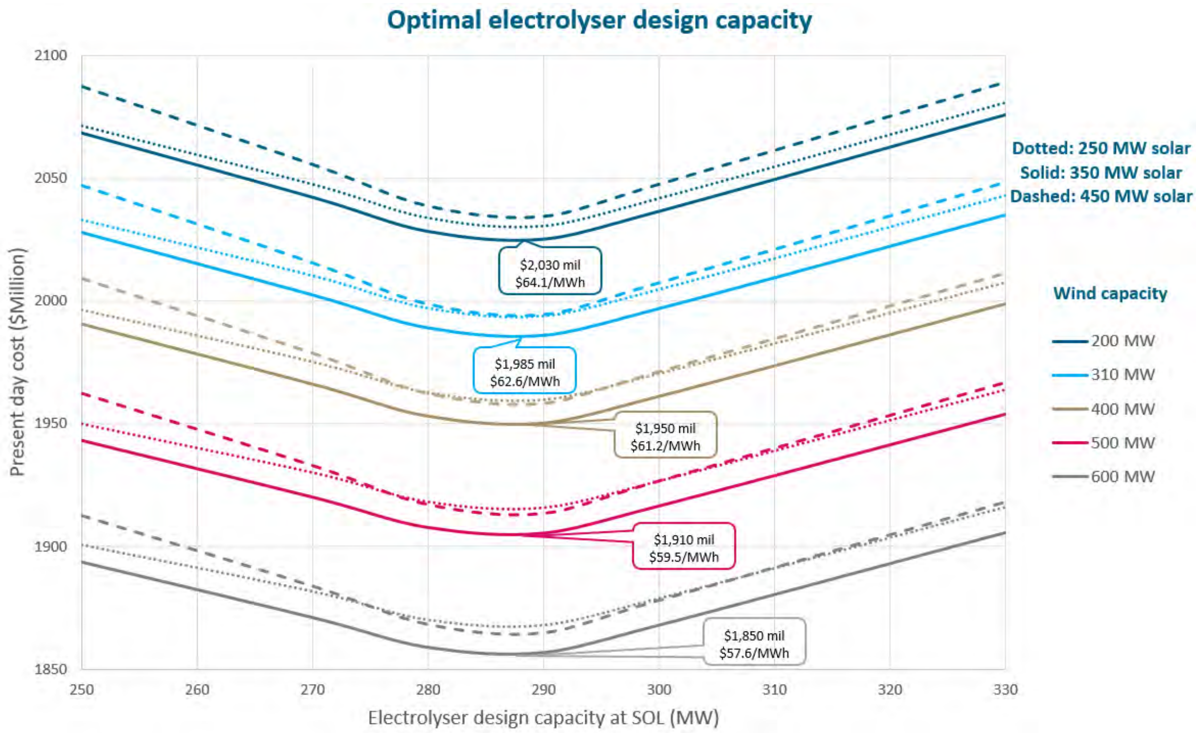


Optimising the sizing of the HPF to achieve the desired overall hydrogen production capacity involves balancing the time/duration cost of the input electricity against the capital cost of the electrolysers. Figure 14 below from the HPF Load Factor Assessment determined that the optimum Phase 1 load factor is achieved when the electrolyser size is 285 MW at SOL and 305 MW at EOL, with a load factor of 84%. Optimisation is also required around the amount of contracted renewable energy provided against grid imports greened by the LGC's/'greening' certificates. Figure 14 clearly shows that progressively increasing wind farm capacity improves project economics, since the average production price is lower than the average spot price when offset by electrolyser power consumption. There is, however, minimal impact from solar on present day cost. To ensure that the continuous power demand from the HPF and HLF can be met by renewable power sources, wind farm capacity of at least 600 MW will be required.

The cost function in Figure 14 illustrates the trade-off between wind capacity, solar capacity, and electrolyser sizing and power cost. If the wind farm capacity is limited to 310 MW, the amount of 'non-PPA' backed power import is 900 GWh/y, for which appropriate 'greening' certificates must be purchased. These are anticipated to be at a cost of $15.4 million/year in addition to the energy (i.e., grid spot price) costs.

On this basis, the recommended load factor that the design should adopt is between 83 and 87% - the minimum cost in each curve on Figure 14. The exact value depends on the standard unit sizes of preferred electrolyser units. The comparatively high load factor reflects a desire to minimise CAPEX and technology risk, but it does increase reliance on grid power and LGC / 'greening' certificate dependence. The minimal grid power draw by the HPF during evening peaks offers both power cost savings and reduced pressure on the national grid.

Figure 14: Impact of solar and wind supply and SOL electrolyser capacity on present-day cost



Note: the optimal present-day cost and the associated weighted average power price is indicated in the callouts.

Phase 2

An analysis of Phase 2 power requirements has been undertaken to confirm the renewable power supply requirement. Similar to Phase 1, solar and wind will be used primarily to supply renewable energy to the HPF and HLF for the full Phase 2 development.

Stanwell provided indicative wind profiles for modelling of the Phase 2 plant power requirement. It was found that a total of 5.0 GW of installed wind capacity and 2.8 GW of solar allows the operation of the Phase 1+2 HPF and HLF while limiting the need for spot power purchases at a practical level. It is, however, suggested that 5.5 GW of wind and 3.0 GW of solar be aimed for to reduce reliance on the grid and therefore reduce risk associated with exposure to power price fluctuations.

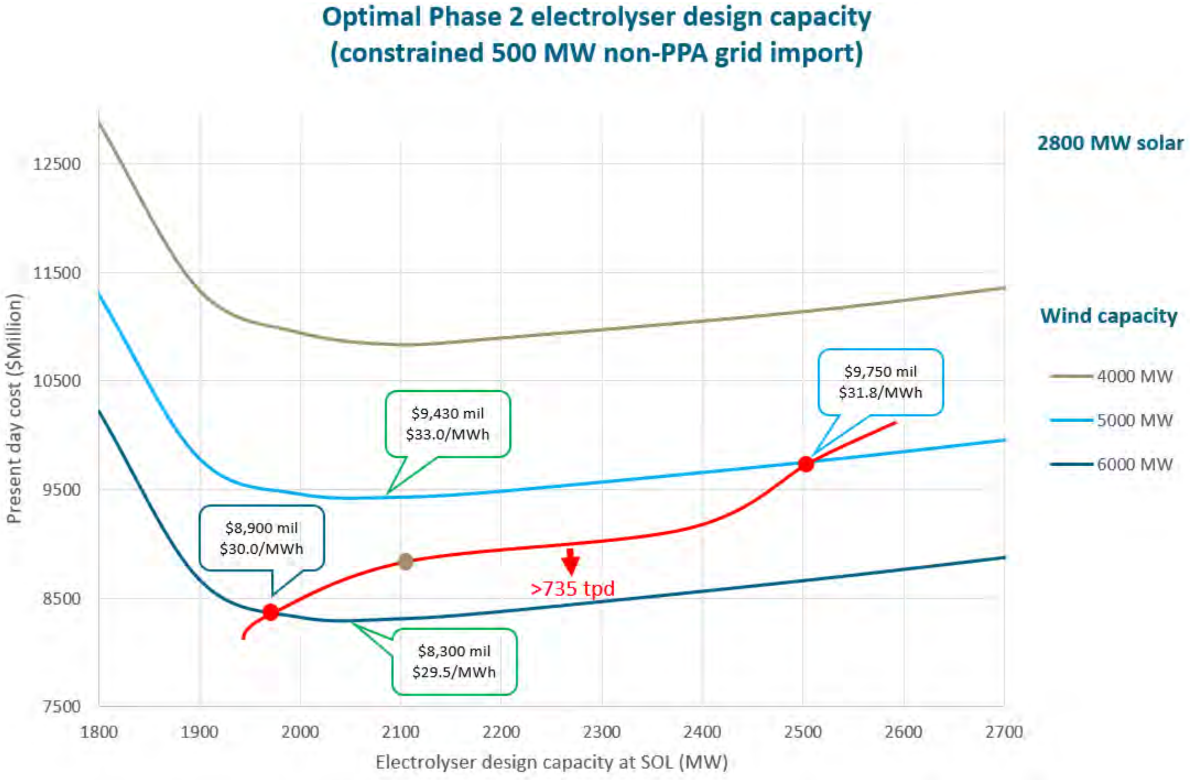
In the first half of 2021, Stanwell undertook a market engagement and sounding process to better understand and assess the extent of planned renewable energy projects expected to be delivered in Central Queensland until 2030. The outcome of this market engagement confirmed that up to 80 projects were identified and that the combined capacity of these was well in excess of the requirements of Phase 2.

The optimisation for Phase 2 is illustrated below in Figure 15. For Phase 2, an electrolyser design capacity of 2,100 MW at SOL (2,300 MW at EOL) is optimal with a corresponding load factor of 83%. This differs from the concept phase where a larger electrolyser with an 64% load factor was found to be optimal. The design change is driven by the ability to use LGCs / 'greening' certificates instead of matching time-of-day electricity generation relying on gaseous hydrogen storage and a slower predicted reduction in electrolyser cost.

If it was required to operate the electrolyser at a lower load factor to reduce grid dependency, Figure 15 suggests that this may be achieved without major impact on the present-day cost of the HPF.

As with Phase 1, increasing the volume of contracted renewable generation reducing the reliance on grid imports has a beneficial impact on overall economics.

Figure 15: Impact of renewable power blend and electrolyser capacity with non-PPA import at 500 MW max.



4.2 Hydrogen Production Facility (HPF) – Phase 1

The HPF is at the core of the Project. The HPF uses demineralised water (raw water that has undergone water treatment) and electricity to produce gaseous hydrogen through the process of electrolysis. This process utilises an electrolyser and requires various utilities including power, raw water (for electrolyser feed input and for system cooling water), and wastewater disposal systems. The gaseous hydrogen that is produced is compressed and either stored or transported through the hydrogen pipeline to the liquefaction facility.

The Phase 1 HPF development is sized to produce sufficient hydrogen to permit the export of 100 tpd of liquefied hydrogen.

4.2.1 Location, land and plot plan (Aldoga)

The proposed HPF will be located on land at Aldoga, approximately 20km from Fisherman's Landing at the Port of Gladstone. Land optimisation has been undertaken and is summarised below.

Due diligence on the Aldoga site was conducted as part of the Feasibility Study and early in the Feasibility Study, three high-level earth works concepts were developed.

The Aldoga site review involved completion of a technical assessment and due diligence of the capacity of the site to support the HPF. The assessment focused on the identification of technical challenges / fatal flaws of site constraints that would limit the ability to develop the proposed facilities. The due diligence involved assessment of the following: high-level geotechnical assessment and walkover of the site, environmental (vent / flare plume rise), contamination (Phase 1 Environmental Site Assessment), ecological values, Aboriginal cultural heritage, flooding / surface waters, civil earthworks and access, and plot plan implications.

A concept that yielded 121.5 ha, whilst minimising disturbance of a watercourse, was selected for advancement (base case). The earthworks proposed resulted in a 45.5 ha north-western pad and

76 ha south-eastern pad, with a further potential 8.6 ha developable area available south of Larcom Creek. Development of one of the remote pads is proposed for the location of Phase 1 switchgear. The useable land footprint could be increased to 143 ha (alternative case), should a larger footprint be required. The HPF land requirement is highly dependent on the electrolyser technology (compact versus non-compact and stacked versus non-stacked).

A summary of the due diligence outcomes is provided in the aforementioned technical memorandum.

Based on the assessment undertaken, the proposed site is deemed suitable for the development, in particular:

- Geotechnical studies do not show any major risks or impediments (as long as permanent structures are not proposed to be developed near the mapped fault along the western boundary subject to further verification);
- While environmental approvals will be required, the environmental desktop assessments do not indicate any significant constraints;
- Cultural heritage and ecological assessments indicate no significant impediments; and
- Earthworks will require blasting and compaction, but a good surface can be developed that is not compromised by potential flood inundation.

The proposed earthworks pads and Phase 1 plot plan are summarised in Figure 16 and Figure 17 below.

Figure 16: Proposed (Base case) earthworks general arrangement

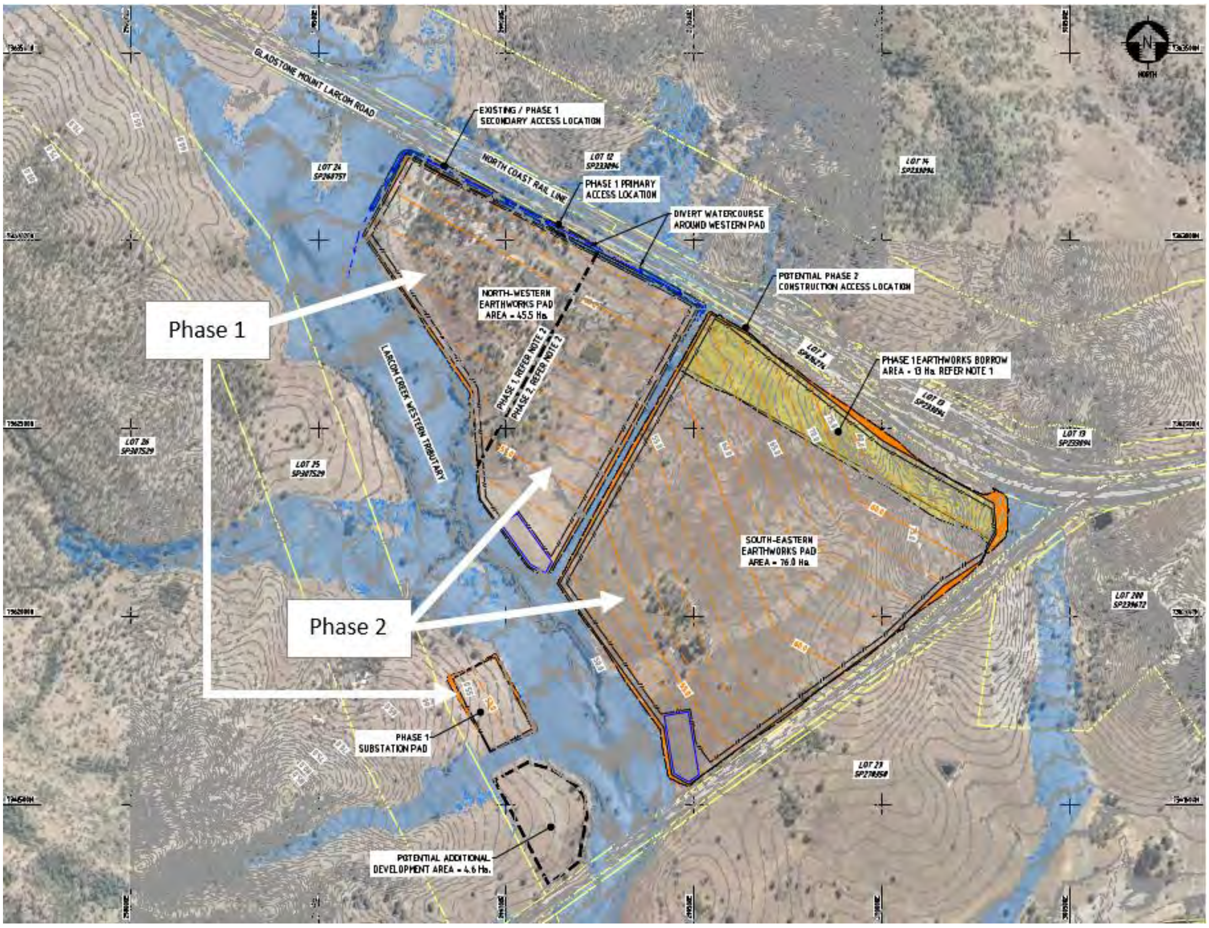
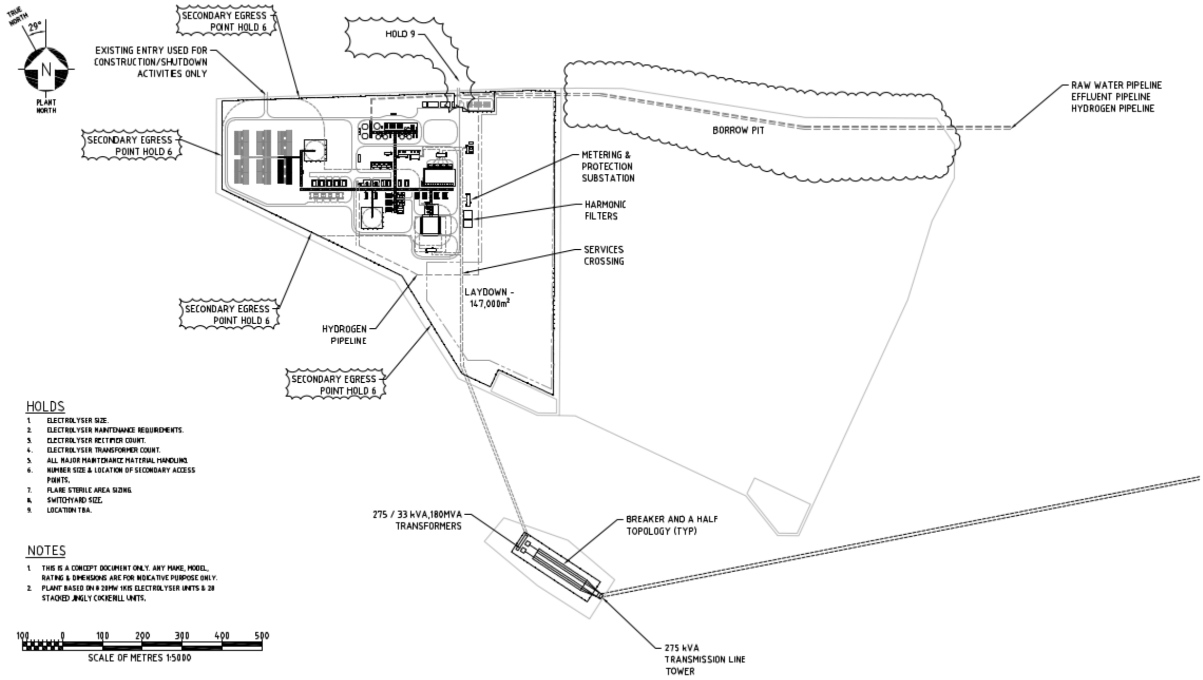


Figure 17: Phase 1 HPF plot plan



Development of the HPF plot plan has been undertaken to enable phased site development. Factors considered in the layout included:

- Access from the Gladstone Mount Larcom road (the site currently has one main access point from the Gladstone Mount Larcom Road, with a new intersection for Phase 1 likely to be required for construction traffic. This to be confirmed by the Traffic Impact Assessment (TIA));
- HV power transmission lines from Larcom Creek substation;
- Potential hydrogen export pipeline routes to the HLF;
- Site topology and existing watercourses.

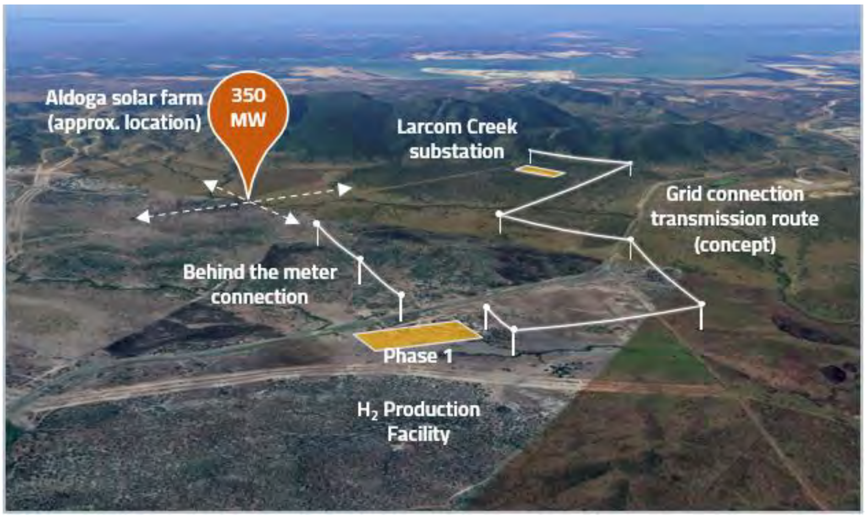
Earthworks and design recommendations/decisions pertaining to the earthworks and HPF plot plan are included in the aforementioned technical memorandum. Earthworks and plot planning will be further optimised during FEED.

The required HPF footprint is highly dependent on the footprint of each individual electrolyser. The current proposal can accommodate hydrogen production facilities that can support 800 tpd of liquid hydrogen equivalent, provided the electrolysers have a compact form, and relatively high load factors. Design and cost estimates were included for less compact designs where the electrolysers needed to be ‘stacked’ in order to fit within the available land area.

4.2.2 Power transmission and network services

An assessment of HPF Phase 1 power requirements was conducted as part of the Feasibility Study. The national electricity grid adjacent to Gladstone is likely to have sufficient strength to enable the import of this required power required for the proposed Phase 1 development.

Figure 18: Proposed BTM and Grid Connections to HPF Phase 1



A Short Form Assessment (SFA) was prepared by Powerlink with concepts for connection and indicative cost estimates for HPF Phase 1 power.

As part of the technical workstream assessment, various power transmission options were considered for HPF Phase 1. These were evaluated using a multi-criteria assessment (MCA), which included assessment of economic considerations, schedule considerations, social and community impact, technical integrity and risk exposure, environmental impact, and development and execution robustness.

The MCA results suggested the preferred high voltage transmission method was for the Project to develop a 275 kV network connection to Larcom Creek substation and a 33 kV BTM connection to the solar farm nearby. Detail on the power transmission and network services solution to be advanced to FEED is outlined below.

The proposed BTM connection would be via a dedicated 33 kV network. Key design elements include:

- Use of overhead HV conductors for routing;
- Construction to be two poles consisting of 4 circuits on each;
- Requirement for directional drilling to traverse underneath the existing highway, railway line and an active railyard proposal.

The NEM-supplied power to HPF Phase 1 requires installation of a 275 kV connection from the Larcom Creek substation. A key design element involves installation of a temporary switchyard and transformers for Phase 1 in the south-western area of the Aldoga site. Electrical equipment will then be rebuilt to the south-eastern pad (as part of the Phase 2 development) once the Phase 2 pad earthworks are complete, and Phase 1 temporary equipment decommissioned. This will assist in avoiding SIMOPS issues during Phase 2 construction, and pre-investment in Phase 2 earthworks during Phase 1.

The possibility of the HPF offering Frequency Control Ancillary Services (FCAS) was also examined as part of the Feasibility Study. While electrolyser plants will be capable of delivering some types of FCAS (depending on the technology employed), the higher value higher speed FCAS was least likely to be deliverable and the economics of large scale FCAS provision are uncertain to the point of not being readily included in the economic modelling. Work is continuing with Powerlink on other ‘load curtailment’ strategies that offer value to the wider NEM in return for reducing costs for the HPF and will be detailed during FEED.

4.2.3 Water supply and treatment

The Phase 1 HPF estimated raw water demand was up to 600 ML/year, to support 100 tpd equivalent hydrogen production, with key water demands including:

- Demineralised water for consumption in HPF electrolysis; and
- HPF cooling water system make-up.

The water demand has been reduced from the Concept Study through the introduction of air cooling as a solution to meet cooling requirements and to reduce reliance on cooling water. The water demand is dependent on the quality of the water source and electrolyser technology selection.

An assessment of the options for HPF Phase 1 water supply and treatment was conducted as part of the Feasibility Study.

Various options were investigated including local supply, long distance pipeline from other catchments, sea water desalination, ground water, and recycled water.

The analysis determined that local - supplied water is the most cost-effective solution, however there is a limit to the availability of this water source, and a risk to supply during periods of low inflow. A trade-off exists between the source water quality and associated costs. More specifically, source water of a poorer quality is associated with increased power usage, water treatment costs (CAPEX and OPEX), and infrastructure costs (e.g., increased pipe diameters, increased effluent disposal requirements with respect to volumes and contaminant level).

Water supply for electrolysis needs to be of a high quality. Given the water quality from the raw water network, a single pass RO and CEDI demineralisation system is required for the Phase 1 HPF. This will provide demineralised water.

4.2.4 Wastewater management

The HPF derives wastewater from both the demineralisation of water consumed in the electrolysis system, and blowdown from a small cooling tower. The expected annual wastewater volume for Phase 1 HPF is 109 ML/year.

An assessment of HPF Phase 1 wastewater management was conducted as part of the Feasibility Study, and a summary is presented below.

Various options were investigated including evaporation ponds, near zero liquid discharge treatments, irrigation, disposal via trade waste sewer, and ocean outfall solutions.

While it is preferred that the Phase 1 wastewater option be relevant to Phase 2 development, scheduling and practicality may result in the solution for Phase 1 being different from that for Phase 2.

4.2.5 Plant – Electrolyser

4.2.5.1 Electrolyser market trends

The electrolyser unit is central to the operation of the HPF and is used for splitting water into hydrogen and oxygen via electrolysis. The capital cost of electrolyser units is high in comparison to fossil fuel alternatives for hydrogen production, however research and development has yielded a decline in associated costs over the past decade. This trend is anticipated to continue, as the drive for renewable hydrogen accelerates and encourages large scale manufacturing capacity.

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation which provides a wide range of products and services supporting the transition to a sustainable energy future. IRENA researchers have hypothesised that over time, larger and more cost-effective production modules are expected, due to increasing interest in the use of renewable hydrogen. IRENA’s forecast trend in capital investment for various technologies is provided in Figure 19 below. IRENA have also developed the below graph (Figure 20) outlining the expected improvement across a number of key indicators, with the forecast indicating significant improvements in capital cost efficiency and slow improvement in energy efficiency of technology over the long term to 2050.

Figure 19: Electrolyser CAPEX forecast as a function of module size for various technologies[41]

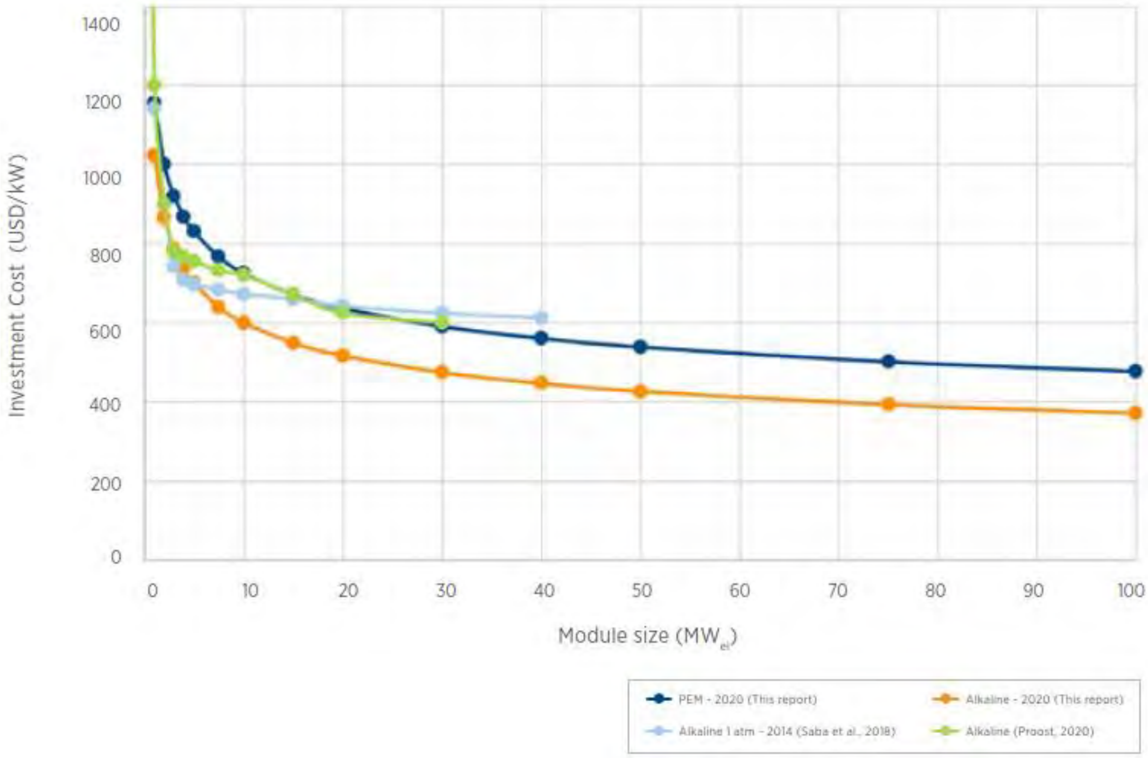
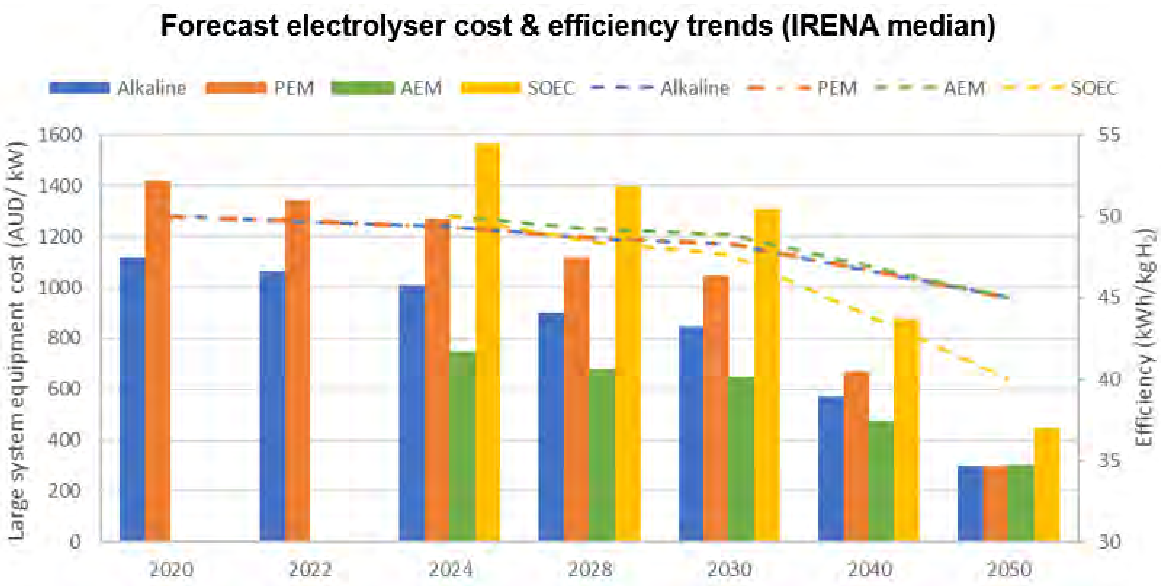


Figure 20: IRENA key performance indicators for different electrolyser technologies in 2020 and 2050[42]



41 IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5oC Climate Goal; Saba et al., 2018; Proost, 2020

42 IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal

The Feasibility Study considered 5 technologies for electrolysis:

1. Low pressure (LP) alkaline and High pressure (HP) alkaline;
2. Proton exchange membrane (PEM);
3. Membraneless;
4. Anion exchange membrane (AEM); and
5. Solid oxide electrolyser cells (SOEC).

Alkaline electrolysers are a mature technology having existed for more than 70 years and are considered the industry “work horse” with the largest market share for high-capacity facilities. This type of electrolyser is generally more energy-efficient technology. The technology development for the majority of engaged alkaline vendors, is stagnant or unclear.

PEM electrolysers are a newer and more flexible technology, with the ability to vary production rate over a shorter response time and wider operating range. Many PEM technology vendors are actively working to increase module sizes and reduce BoP equipment to offset the higher capital cost of this technology.

Other emerging commercial technologies include membraneless and SOEC. A key benefit of such technologies is the ability to address issues inherent to alkaline and PEM electrolyser technologies, including large footprints and high refurbishment costs. It is expected that as the industry matures, these technologies will become cost competitive with alkaline electrolysers.

4.2.5.2 Vendor engagement

In order to select an electrolyser vendor for the Project, a vendor and technology engagement and assessment process was adopted. These assessments were undertaken as an integral part of the Feasibility Study, and the approach and outcomes are described below. A detailed vendor engagement process will be undertaken as part of FEED. This is referenced below in Section 11 (Phase 1 Execution Strategy).

4.2.5.3 Vendor competition

The analysis of vendor engagement that was conducted as part of the Feasibility Study. The aim of the vendor assessment was to identify a preferred electrolyser vendor engagement plan for implementation in Phase 1 FEED. The creation of an execution strategy that encourages and rewards innovation and cost saving in equipment operation and installation was identified as a key opportunity.

Various technical aspects were considered during vendor engagement and a MCA undertaken. The MCA involved assessment of life cycle cost, Queensland Government & public buy-in, grant funding conditions, robustness and technical risk, schedule, safety, social impact, and decarbonisation value.

To minimise single vendor risk, and to encourage vendor competition through Phase 1 and prior to award of the Phase 2 electrolyser scope, the Feasibility Study analysis considered a two electrolyser vendor approach for Phase 1.

Under this approach, the electrolyser units will be configured as two trains of roughly equal capacity, with Train 1 being a low-pressure train and Train 2 being a high-pressure train. This approach will be refined at the FEED stage.

It is assumed that the preferred Phase 1 vendors would be engaged for Phase 2. The ability for the Project and Phase 2 electrolyser vendors to improve performance through Phase 1 will be critical to achieving a best possible economic outcome for the Project overall. The preferred vendors are likely to be the ones that best show a clear technology developmental pathway and can demonstrate industry leading performance in driving down the LCOH.

4.2.5.4 Technology selection

An assessment of electrolyser technology options was conducted as part of the Feasibility Study. The comparative assessment considered 5 technologies for electrolysis:

- LP alkaline and HP alkaline
- PEM
- Membraneless[43]
- AEM
- SOEC

For the purpose of the financial model, two vendors were used as proxies for Phase 1 (50:50 split) and a single vendor was assumed for Phase 2. The approach to vendors will be further developed in the FEED Study.

A summary of the advantages/disadvantages of each type of technology is provided below in Table 21:

Table 21: Summary of advantages and disadvantages of electrolyser technologies

Technology	Advantages	Disadvantages
Alkaline	• Well established • Lower CAPEX • Long lifetime • High efficiency meaning reduced OPEX • No costly precious metals required as catalyst	• Low current density • Corrosion due to electrolyte • Slow start up and low dynamic range • Lower purity of gas • More components / more complicated maintenance
PEM	• High current densities • Compact system design • Fast start up and dynamic operation • No electrolyte required • Higher operating pressures	• Newer technology • More expensive CAPEX • Requires costly precious metals for catalyst • Acidic corrosive components • Durability not proven
AEM	• No costly precious metals required as catalyst • No electrolyte required • Compact cell design • High pressure operation	• Emerging commercial base • Low current densities • Membrane degradation
SOEC	• High efficiency due to high operating temperature • Steeper learning curve than other technologies • Lower operational and maintenance costs • No costly precious metals required as catalyst	• Emerging commercial base • Shorter stack lifetime

A comparative matrix was developed for the comparison and assessment of the various vendors and technologies. The matrix included seven weighted criteria, listed below:

[43] Not considered further in this report given low score in comparative assessment (refer Table 22)

- Performance warranty / confidence;
- LCOGH;
- Potential for LCOGH improvement;
- Compactness / footprint constraints;
- Execution ease;
- Local manufacturing potential;
- Delivery schedule.

The resultant vendor comparison matrix is provided in the technical memo and a summary of the net scores and rankings is included in Table 22: Vendor comparison. Due to non-disclosure agreements (NDAs) executed between the electrolyser vendors and the technical advisor, the vendors were assigned a letter from A to N, with technology type and company nationality also noted. For the purpose of the assessment, Vendor E was chosen as the comparison baseline.

Table 22: Vendor comparison

Vendor		Net score	Rank
A	LP Alkaline (European)	n/a	-
B	LP Alkaline (European)	40.5	1
C	HP Alkaline (Asian)	-175.0	-
D	HP Alkaline (Asian)	-133.0	-
E	HP Alkaline (European)	15.0	3
F	HP Alkaline (European)	n/a	-
G	HP Alkaline (European)	-16.5	Equal 5
H	PEM (European)	-131.0	-
I	PEM (European)	-25.0	Equal 5
J	PEM (European)	-59.0	-
K	PEM (European)	0.0	Equal 4
L	PEM (European)	38.0	2
M	Membraneless (European)	-56.5	-
N	SOEC (American)	-4.5	Equal 4

Due to footprint constraints, Vendors A and F were not considered for progression. The top 3 vendors across the technologies were thus identified as Vendor B, Vendor L, and Vendor E. Given the minor separation of PEM vendors, it is important to note that advancements during FEED could alter the rankings. Membraneless (Vendor M) and SOEC (Vendor N) technologies were also identified as options to consider as the technologies advance during FEED. A top rating is generally reflective of a more progressive vendor, with these vendors also reporting better efficiency. The evaluation of the various vendors noted the following:

- Vendor B has proven Chlor-Alkali technology with a number of recently awarded contracts
- Vendor L is the top-ranked PEM option, however as Vendors I and K are very close in the rankings to L, advancements in the period to FEED could alter the rankings
- Vendor E has demonstrated a good track record with its electrolyers, is demonstrating steady advancement, and has indicated a willingness to engage in exploration of "stack" options to reduce the footprint. Vendor E also has the capacity for establishment of local manufacturing.

For the purpose of the Feasibility Study, the Project was assessed on the basis of two different technologies, with further refinement to be undertaken during FEED. On the basis of a 2 x 50 tpd equivalent offering, there are currently four combinations that have merit:

- Best LP alkaline and best PEM;
- Best HP alkaline and best LP alkaline *(current plot plans reflect this combination)*;
- Best HP alkaline and best PEM;
- Best LP alkaline and pilot of other technologies.

As the Project progressed into the Feasibility stage and actual CAPEX cost data was collected from vendors, it was found that the Concept Study cost assumptions did not accurately represent the expected CAPEX post-2021. Key challenges and events that arose during the course of the Feasibility Study that are anticipated to contribute to the cost escalation include the COVID-19 pandemic and the current conflict unfolding in eastern Europe, and the resultant uncertainty and impacts on global and domestic supply chains, flow-on effect on cost of goods and services (including raw material prices) and impacts on contingencies and schedules.

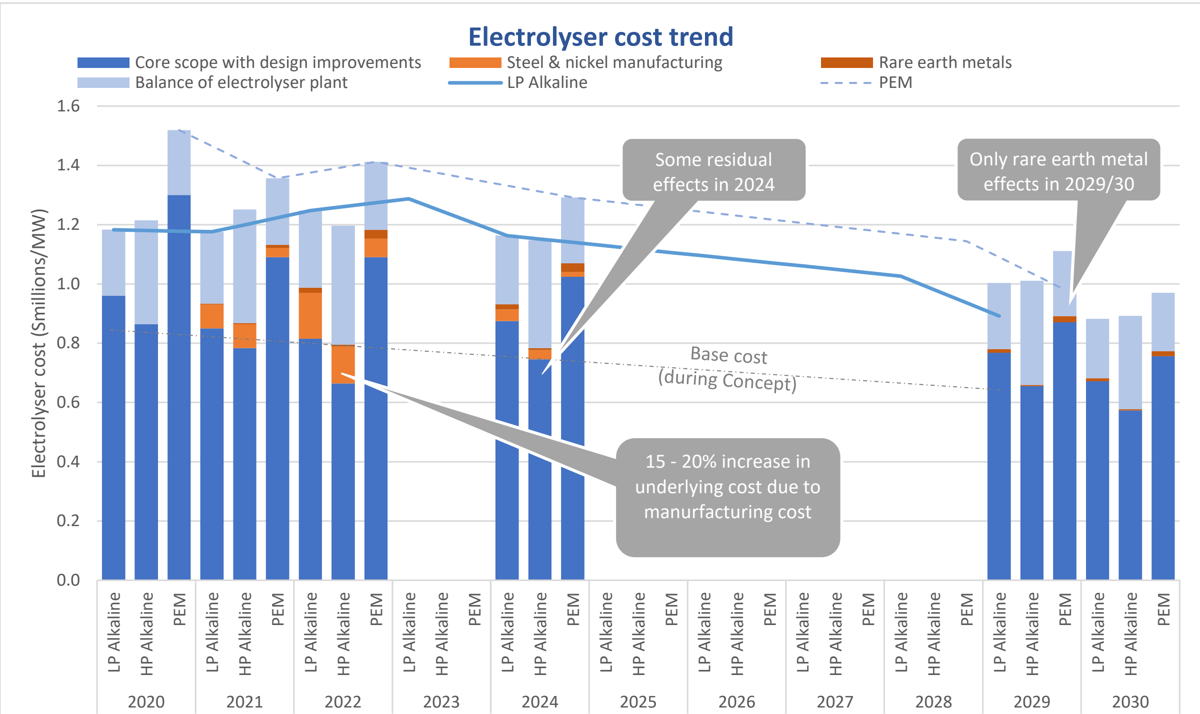
The estimated capital costs received from vendors exceeded the values provided in 2020/2021, which prompted an evaluation of the impact of near-term cost increases in the metals markets and steel manufacturing sectors[44]. Vendors indicated current price increases between 15-20% were attributable to the current market trends, and that firm contracts were not being signed until cost volatility had settled.

Analysis was conducted on the impact of technology evolution on the cost of the 'core' electrolyser scope over time, which identified partial cost recovery by 2024 and nearly full recovery by 2029.

By 2024, market tension is expected to have eased considerably, however some residual effects will still be present, with the cost of the electrolyser module remaining higher than the Concept Study base case. The effects of manufacturing pressure on steel and nickel should be inconsequential by 2029, however it is likely that tension in the rare earth metal market will still be present.

Refer Figure 21 for a comparison of cost trends across various electrolyser technologies.

Figure 21: Comparison of cost trends for different electrolyser technologies



44 https://ihsmarkit.com/research-analysis/global-manufacturing-growth-revives-from-1-year-low-but-supply-shortages-and-inflationary-pressures-persist-mar22.html

Based on the analysis, the expected cost of the electrolyser modules provided by Vendors B and E in 2024 and 2028 have been calculated – refer Table 23.

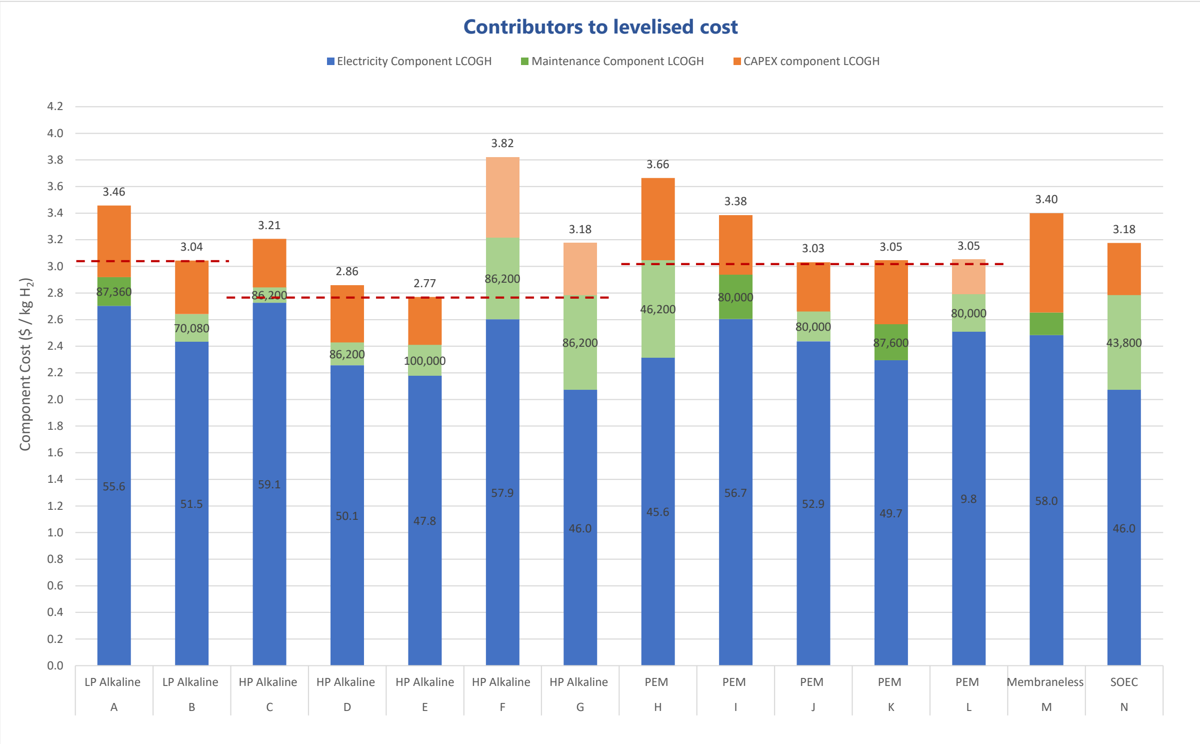
Table 23: Expected cost of electrolysers for Phase 1 and Phase 2

Cost (in $AUD M)	Vendor B (20 MW module)	Vendor E (5 MW module)
Cost given by Vendor (2022)	19.4	4.00
Expected cost in 2024	18.3	3.94
Expected cost in 2028	15.3	3.65

The economic performance of vendor offerings is often a key metric of interest to Project proponents. For electrolysers, the operating costs (specifically electricity costs), are significantly larger than the capital costs, and hence levelised production / lifecycle costs are a useful metric to accurately determine equipment cost over its lifetime. Project success is reliant on significant improvements in cost efficiency prior to Phase 2 equipment procurement.

As shown in Figure 22, the LCOGH is dominated by the cost of electricity. Small changes in unit efficiency and even differences between reported performance on vendor websites and the reported value in datasheets (i.e. 0.1-0.2 kWh/m³), is sufficient to move a top ranked LCOGH vendor to a low ranked vendor and vice versa.

Figure 22: Electrolyser contributors to levelised costs



4.2.5.5 Process for engaging potential electrolyser vendors

The electrolyser is the core component of the HPF and accounts for ~50% of the plant capital costs and more than 80% of the operating costs. As a major component, it is essential that the cost estimates match the overall Project accuracy. For the Feasibility Study, a Class 4 (i.e. ±30%) is required, however a challenge in estimating costs is present in the Feasibility Study stage as electrolyser vendors have not been formally engaged for the Project.

It was expected at the Project outset that an ECI activity would be undertaken. Early in Feasibility Study execution the scope refined the electrolyser vendor engagement to a Request for

Information (RFI) (only) approach. The RFI approach relied on the goodwill and correct interpretation of the scope from vendors.

The RFI engagement was conducted with a short list of 12 vendors. The short list reflects the top vendors by sales volume and a few emerging technology providers. The list is consistent with the list of vendors that have been approached in earlier phases of engineering.

The LCOH assessment process achieves a fair like-for-like analysis by ensuring that the limits for the assessed scope of all vendors is comparable. For this analysis the assessed scope was broadened to consider key PEM / alkaline technology differentiators such as harmonics filtering, compression (if required), cooling systems, emergency power supply and building structures. The common discharge pressure was 30 barg.

In order to evaluate which vendor-based solutions provide a best fit with the Project, a MCA approach was adopted. The MCA considered elements such as: near term economic performance, innovation potential towards future economic performance, confidence with performance guarantee, technical maturity, constructability, footprint, local content and execution schedule.

The non-disclosure agreements were between vendors the Project's technical advisor and were not executed with the broader Consortium. Hence, only generalised metrics such as LCOH analysis and MCA outcomes are available.

4.2.6 Balance of Plant, Materials and Building

Balance of process plant

The BoP represents up to 10% of process plant capital costs and is critical for ensuring the hydrogen produced meets the target specification. The requirements for BoP equipment are very dependent on the electrolyser technology chosen.

An assessment of HPF Phase 1 BoP was conducted as part of the Feasibility Study. The assessment addressed two key configuration considerations, being the location of the de-oxidation reactor (with the objective of minimising safety risk), and the preferred dehydration configuration.

The technical assessment recommended that full gas dehydration (using molecular sieve dehydration) should be conducted at the HPF. This method significantly reduces dehydration CAPEX/OPEX, and is assumed as the basis for the Feasibility Study cost estimate.

The alternative configuration (involving partial dehydration at the HPF and full gas specification to be met at the HLF) may offer several key advantages and is recommended for re-evaluation during FEED prior to a final decision on overall configuration.

Material selection

An assessment of the materials selection for the HPF and HLF receiving facility was undertaken as part of the Feasibility Study. The scope of the analysis included the HPF plant and associated utilities located between the outlet of the vendor-supplied electrolyser and the HLF receiving facilities. The selection criteria for making materials recommendations for the process streams included risk / safety, capital cost, operational cost (maintenance) and maintainability, technical complexity, and current "standard" practice.

The primary focus of the materials selection was on hydrogen embrittlement and materials suitable to operate with hydrogen. The preference is for austenitic stainless steels (residual martensite-free), followed by aluminium alloys, and finally carbon steels recommended by ASME B31.12 piping components. In addition to the first screening stage, a review of external corrosion for atmospheric conditions and internal corrosion (aside from hydrogen embrittlement) was undertaken. The close proximity of the HLF to the coast is more of a constraint than the Aldoga site for external corrosion.

Building structures

Electrolyser buildings are the largest and most significant building structures on the site. The Project sought to explore the value of maximising modular electrolyser units and stacking optimising electrolyser layout to minimise its footprint on the Aldoga site and generate associated cost estimate for these structures.

The preferred technical solution (2 x 50tpd train configuration) involved a combination of the preferred electrolyser vendor designs. This solution benefits from the technical advantages of these individual offerings – those being the compact (but lower power efficiency) of the one design and the less compact (but higher power efficiency) of the other design. A “double-stacked” configuration of the second was investigated to further reduce its footprint, as part of the Building Structures Technical scope.

The choice of electrolyser building structure design will be finalised in FEED and will be dependent on the vendor engagement during FEED and final electrolyser technology selection.

A modularisation philosophy was also prepared.

Figure 23: Visualisation of electrolyser building Option 1

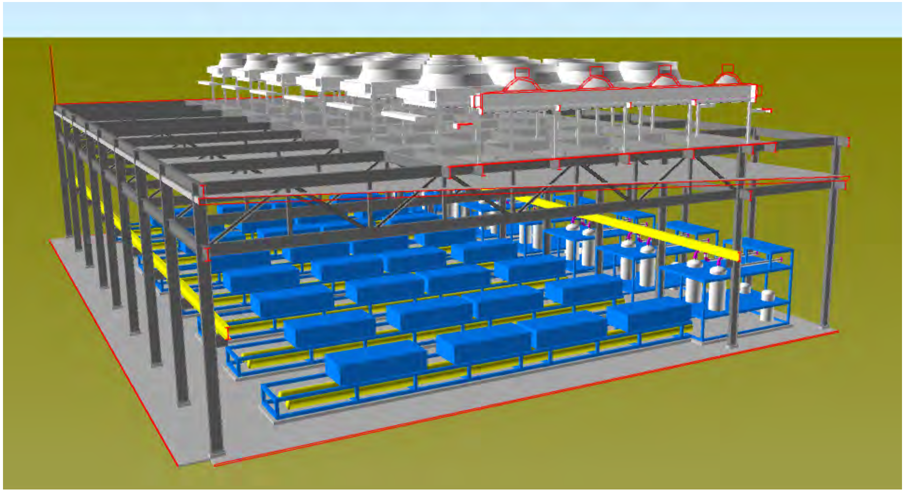


Figure 24: Visualisation of electrolyser building Option 4

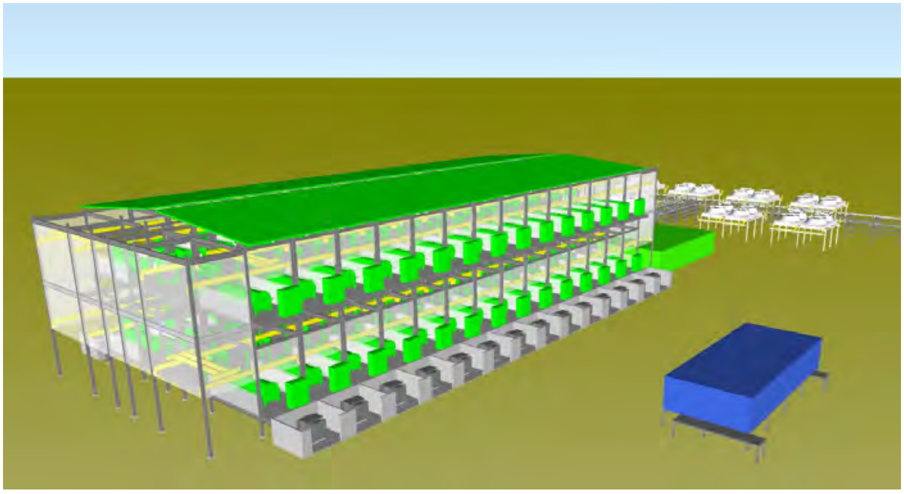
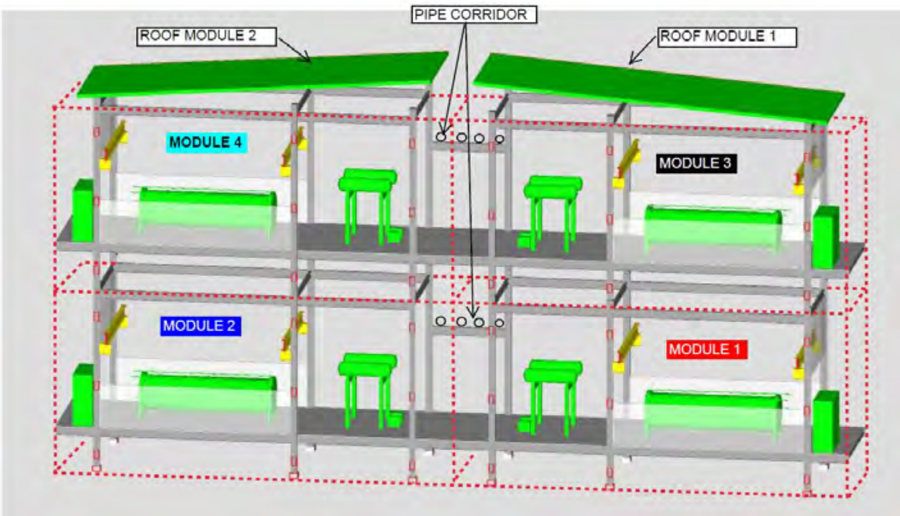


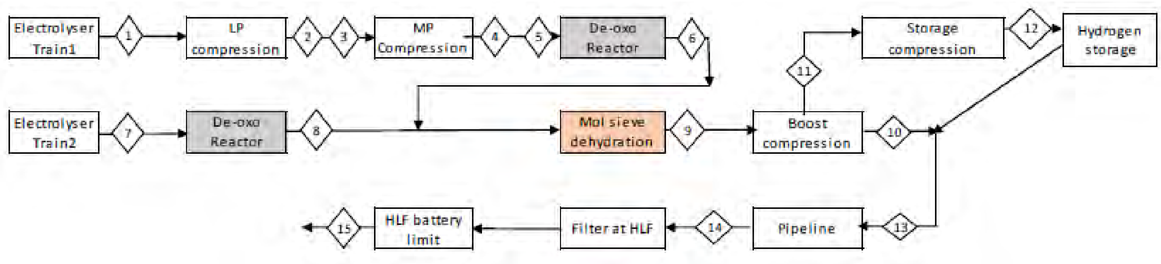
Figure 25: Visualisation of electrolyser modular construction building



4.2.7 Compression and storage

Gaseous hydrogen compression was reviewed as part of the Feasibility Study. Compression is required for storage and pipeline transportation duties, and will be located at the HPF.

Figure 26: Base configuration - molecular sieve dehydration at HPF



Storage of hydrogen was also assessed as part of the Feasibility Study. Storage is required to balance the interface between the variable HPF production and effectively continuous HLF production.

The Feasibility Study assessed different compression and storage technologies along with sizing requirements for both Phase 1 and 2.

Initial compression

Initial compression constitutes the low pressure (LP) / medium pressure (MP) and Boost services required to raise gaseous H2 pressures to 35 barg. A preliminary assessment was undertaken to determine the requirements for initial compression, with preferred solution being positive displacement type (non-lubricated reciprocating compression).

Positive displacement compressors can achieve high compression ratios per stage and are not constrained by the low MW characteristics of H2 gas fluid as for dynamic types (i.e. centrifugal), rendering their utilisation for hydrogen service impractical.

Non-lubricated compressors are recommended for transportation to the HLF given the level of cleanliness required for the export hydrogen.

Storage compression

A non-lubricated reciprocating compressor is the preferred technology for this high-pressure service (up to 350 barg) based on history and performance. However, liquid piston and electrochemical compression are emerging as alternative technology options for this service and should be considered during FEED.

Gaseous hydrogen fixed storage

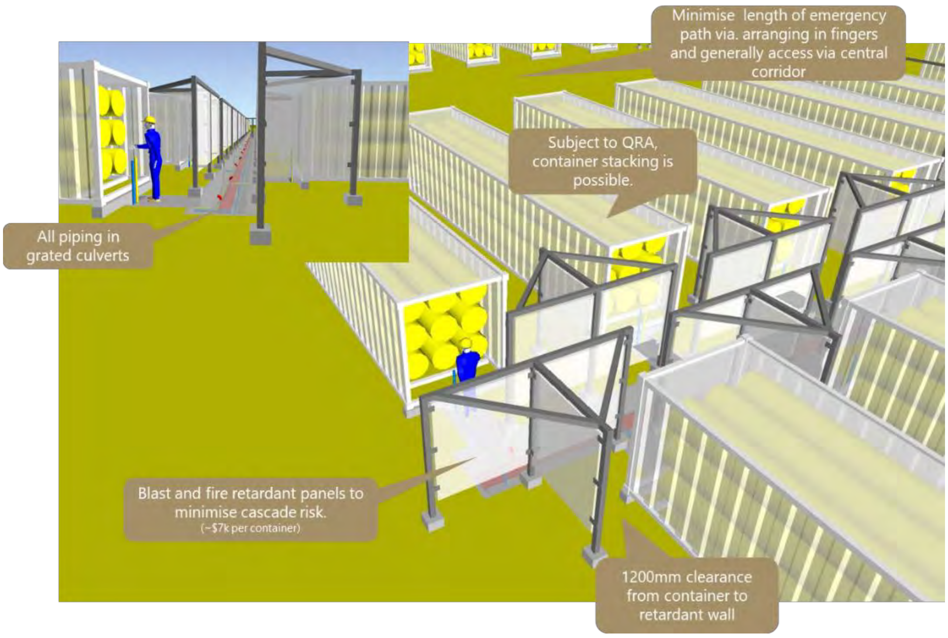
Investigations into storage options were undertaken as part of the Feasibility Study. Storage alternatives were evaluated including both fixed storage (at HPF as well as HLF) and pipeline (linepack) storage. Several factors were considered including lifecycle costs, compression, safety aspects, footprint, technical maturity, usability, as well as production profiles aligning to HPF/HLF requirements and renewable power generation profiles.

Gaseous hydrogen storage is required to balance flow differences between the HPF and HLF. HPF production shall be varied (in response to power pricing and production needs), whilst the production capacity of the HLF is intended to be relatively constant. Therefore, storage at the HPF will be required to enable a more continuous H2 production supply to the HLF, with the optimum quantity of storage for Phase 1 determined to be approximately 20 tonnes.

The analysis determined the preferred technology is Multi Element Gas Containers (MEGC) using a composite (predominantly fiberglass) material. This option was preferred due to its ability to withstand frequent pressure cycles, relatively few connection points, and its relatively low cost.

The analysis also determined that process safety objectives could be met by an alternative MEGC layout / configuration involving MEGC container offset with blast / fire resistant panels (refer Figure 27). MEGC container stacking will be considered in FEED as part of Aldoga site optimisation scope.

Figure 27: Horizontal Composite Overwrapped Pressure Vessels (COPVs) in MEGCs



4.3 Hydrogen Production Facility (HPF) – Phase 2

The Phase 2 HPF will involve a scaled-up version of the Phase 1 facility. The Phase 2 HPF development will produce an additional 700 tpd of hydrogen (total 800 tpd).

Location, Land and Plot Plan (Aldoga)

The HPF for Phase 2 will also be located on the Aldoga site. The full development (proposed earthworks pads) will be located on the 121.5 ha site and is shown in Figure 16 in Section 4.2.1.

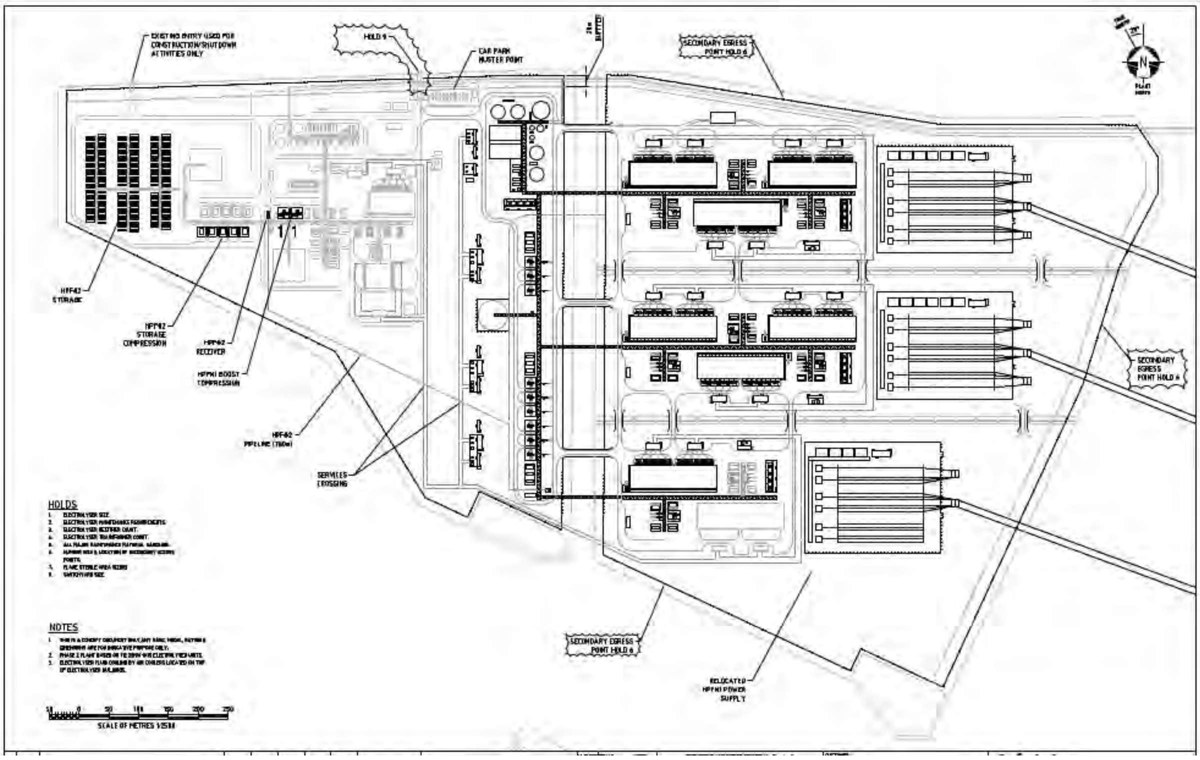
Considerations relating to Phase 1 earthworks and plot plans are also applicable for Phase 2 (refer Section 4.2.1).

Key considerations specific to Phase 2 are outlined below:

- ***Site access:*** a second access (for Phase 2) has been included in the plans
- ***HV switchyards and transformers:*** The HV switchyards and transformers (on the remote pad in Phase 1) will also be relocated in Phase 2 to provide a common switchgear area

The Phase 2 plot plan is shown in Figure 28 below.

Figure 28: Phase 1 & 2 HPF plot plan



Power transmission and network services

The power supply for HPF Phase 2 was assessed. The requirement for Phase 2 HPF is 2,465 MW (SOL). To ensure provision of sufficient power, significant upgrades to the electricity network would be required. Powerlink were engaged to undertake a SFA on the likely augmentation and reinforcements required for Phase 2.

The proposed solution is for a new 500/275 kV network to be constructed throughout the Central QREZ. This would involve:

- Expansion of the Larcom Creek substation to contain both 500 kV and 275 kV switchgear;
- Routing of six circuits of twin Sulphur to HPF Phase 2 (using three towers and a 100m easement);
- Connection of the transmission line into three new 275 kV switchyards (with each consisting of five bays of 2500A switchgear);
- 20 transformers would be required.

The preference is that Phase 2 power supply to the HPF be at 275 kV, with the 500/275 kV transformers being located in the 500 kV expanded Larcom Creek switchyard. Further discussions are required with Powerlink to determine the optimal location for switchgear and transformers for connection to the 500 kV system.

Power transmission routes were identified based on current easement corridors and will be refined during FEED.

Harmonic filtering and FCAS have also been considered.

Water supply and treatment

The total Phase 1+2 HPF raw water demand is estimated to be 4,800 ML/year to support 800 tpd equivalent hydrogen production. An assessment of the options for HPF Phase 2 water supply and treatment was conducted as part of the Feasibility Study.

The approach was taken to prepare connection applications early in the study (on the basis of an Open Cooling Water system at the HLF), with one of the key aims being to determine if GAWB could meet the Phase 1+2 demand for the HPF of 4,800 ML/year at the Aldoga site (as well as meet the demand of the HLF)..

The options considered for the water supply are the same as outlined for the Phase 1 HPF (Section 4.2.3).

Wastewater management

The preferred wastewater disposal option for HPF Phase 2 is ocean outfall, with a pipeline transporting wastewater from the HPF to the likely ocean outfall location at the HLF. The volume of wastewater for HPF Phase 1+2 is estimated to be 875 ML/year.

Balance of Plant, materials and building

Plant – Balance

The key Phase 1 decisions with respect to the BoP have been carried through to Phase 2.

Building structures

The Phase 2 structural considerations are the same as for Phase 1. It is assumed that Phase 1 will be completed and operational during Phase 2 construction. Given this, road access and construction methodology as well as laydown areas and size of construction equipment (e.g., cranes, etc.) must be considered during Phase 2 building design.

Compression and Storage

Initial compression

The Phase 2 compression solution is anticipated to be a scale up of Phase 1 technical solution. The opportunity does exist to assess the practicalities and cost of Phase 1 compressor unit standardisation for Phase 2 in comparison with the application of larger-scale compressor units where benefits may be achieved from reduced CAPEX and O&M costs.

Gaseous hydrogen storage and compression

The much larger storage requirements for Phase 2 may use the storage type that was selected for Phase 1.

The assumption has been made that the actual data for costing, procurement, safety and risk management measures and constructability will be available at the end of Phase 1 execution, and the learning from these can inform which method is the most suitable for Phase 2 storage. Additionally, material-based storage solutions (i.e., metal hydrides) may be relevant by Phase 2.

4.4 Pipeline – Phase 1 & 2

The hydrogen pipeline provides the connection between the HPF and HLF and is used for the transport of compressed gaseous hydrogen. As part of the Feasibility Study, the pipeline route, design and sizing were assessed, and decisions made on configurations to be progressed to FEED.

As part of the assessment, a report on pipeline routing, materials and design was prepared.

Pipeline routing

Screening of routes for the proposed pipeline examined three potential pipeline alignments.

The three routes were evaluated using a multi-criteria analysis (MCA) which sought to balance the Project's key execution and operational drivers.

The MCA encompassed qualitative and quantitative components. Qualitative elements include (but are not limited to) ease of constructability, logistics, and operability. Quantitative elements include (but are not limited to) overall length, number of crossings, number of property owners, number of mining leases crossed, and length of pipeline in length of Endangered Regional Ecosystems.

Although land tenure and pipeline right of way easement acquisition considerations was not formally within the scope of the Feasibility Study, it is worth noting that the P&G Act does not currently cover hydrogen gas pipelines, and as such assurance of the preferred pipeline route does not benefit from compulsory acquisition rights the Queensland government holds under that legislation.

Pipeline design and sizing

The Feasibility Study considered both the design and sizing of the pipeline. During the Concept Study, it was proposed that the pipeline would provide hydrogen storage of up to 12 tonnes through pressure swing. Counter to the Concept Study findings, an assessment completed as part of the Feasibility Study identified that fixed storage at the HPF site was more cost effective and presented a lower risk compared to pipeline-based storage. Various pipeline options were considered and assessed.

It was determined through the assessment that the most cost-effective design was a single DN500 pipeline, operating in "no storage" mode. This option balances pipeline capital cost and compressor duty and operating cost. It was determined that using pipelines as a storage mechanism was not cost-effective compared to fixed storage options. The Feasibility Study also considered Phase 2 pipeline requirements and it was determined that the pipeline for Phase 1 should have sufficient capacity for Phase 2 requirements. A pipeline sized appropriately for Phase 2 will be progressed in FEED.

A cost effective method to allow capacity in the pipeline for other users would be to increase the Maximum Allowable Operating Pressure (MAOP) relative to that required for the project alone. It was concluded that pre-investment (with some consideration of future common user capability) was the preferred approach.

4.5 Hydrogen Liquefaction Facility (HLF) – Phase 1

The HLF is the final stage in the supply chain before hydrogen is loaded and shipped. Compressed gaseous hydrogen enters the HLF via the hydrogen transport pipeline. Once at the HLF, the gaseous hydrogen is converted into liquefied hydrogen. This process utilises a liquefier and requires various utilities including power, raw water (for cooling water), and wastewater disposal systems. The liquefied hydrogen is stored and loaded onto LH2 carrier vessels for international offtake.

4.5.1 Power transmission and network services

The Phase 1 HLF is to be located on the eastern edge of Fisherman's Landing, at the Port of Gladstone. The HLF power demand for Phase 1 is ~70 MW, with intermittent peaks of 75 MW.

This area is currently supplied with a 66 kV electricity distribution network from the Boat Creek substation, owned by Ergon. This network is in turn supplied from two incoming 132 kV lines. The existing 66 kV network is not sufficient and cannot be economically upgraded to support the HLF Phase 1 power demand. A new transmission line is required and will be investigated during FEED.

Though a double circuit 132 kV connection would be sufficient for the HLF Phase 1 power demand, it would be insufficient for Phase 2. Given this, a double circuit 275 kV connection is the preferred option that has been advanced as the preferred transmission approach.

4.5.2 Water supply and treatment

The estimated raw water demand for the Phase 1 HLF is up to 1,396 ML/year, to support 100 tpd of hydrogen liquefaction, with water requirement being for the HLF cooling water system. The water demand is dependent on the quality of the water source.

An assessment of the options for HLF Phase 1 water supply and treatment was conducted as part of the Feasibility Study. Various options were investigated including raw water supply, long distance pipeline, desalination, ground water, and recycled water.

The analysis determined that raw water is the most cost-effective solution, however there is a limit to the availability of this water source, and a risk to supply during periods of low inflow. A trade-off exists between the source water quality and associated costs. More specifically, source water of a poorer quality is associated with increased power usage, water treatment costs (CAPEX & OPEX), and infrastructure costs (e.g. increased pipe diameters, increased effluent disposal requirements with respect to volumes and contaminant level).

Given the water quality from the raw water network, a simple clarifier and filter is required for the Phase 1 HLF, for the provision of cooling water.

4.5.3 Wastewater management

The expected annual wastewater volume for Phase 1 HLF is 571 ML/year.

An assessment of HLF Phase 1 wastewater management was conducted as part of the Feasibility Study. The options investigated included, evaporation ponds, near zero liquid discharge, irrigation, disposal via trade waste sewer, and ocean outfall solutions.

The preferred option for Phase 1 is an ocean outfall solution, with the design of this system to be further developed during FEED.

4.5.4 HLF receiving facilities

The HLF receiving facilities were assessed to ensure a custody metering and analyser system that was both suitable and certifiable could be provided, based on anticipated process conditions. Different metering technology and anticipated analyser requirements were examined as part of the assessment.

There are several packages that constitute the HLF receiving facilities:

- Pig receiver and pipeline maintenance equipment;
- Hydrogen filtration assembly;
- Hydrogen custody metering, quality, and pressure control package (referred to as custody metering package).

As the pipeline is to be designed for Phase 2 rates, the recommendation was that the design of the packages is suitable for accommodating Phase 2 rates with minimal modification.

4.5.5 Fisherman's Landing site review

It is proposed that the HLF be located at Fisherman's Landing at Port of Gladstone (approximately 10km north-west of Gladstone city precinct).

Due diligence was then conducted for the HLF at Fisherman's Landing as part of the Feasibility Study. The site was selected for the following reasons:

- Location is less space constraining, with the greenfield site offering greater opportunity for a larger plant footprint, and future expansion potential;
- Location is technically acceptable, permitting construction of a wharf sufficiently long to berth the LH2 carrier, and with sufficient separation from adjacent wharves to meet shipping safety requirements;
- Less constraining for product offload, as wharf would be single vector export (LH2) only;
- Site offers greater potential to minimise LH2 loading boil-off gas production, with greater port / water frontage on offer to maximise waterfront LH2 storage, and significantly shorter wharf length.

4.5.6 Wharf facility

The location of the wharf facility and the adjacent HLF is a key consideration of the Feasibility Study. A number of requirements and design considerations form the basis of the assessment and include Phase 2 suitability, existing infrastructure, size, distances from HLF to LH2 ship loading facilities, berth access and docking.

The features of the Gladstone Port and Fisherman's Landing precinct are shown in Figure 29. Key features of the port and precinct are detailed below:

- The port covers an extensive area within a harbour protected by Curtis Island and Facing Island, and has 24 separate berths – three berths on Curtis Island (associated with the LNG terminals) and 21 berths spread over ~17km on the mainland side of the harbour
- The Fisherman's Landing precinct is located at the upstream extent of the harbour, with current development comprising of Berths 1-5
- GPC reclamation program at the northern end of the precinct – to provide additional 2.2km of berth line and ~213 ha of terminal area for future industries
- Precinct vessel access is via the Targinnie Channel (120m wide and 10.6m deep, with maintained depth decreasing to 9.0m at the channel's upper end in front of Berths 4 & 5)

Figure 29: Gladstone Port (source: GPC)

4.5.6.1 Berth access

Berth access was a key consideration during the Feasibility Study, with assessment undertaken to ensure successful navigation to and from the berth could be achieved.

A report was prepared that examined navigation considerations associated with accessibility for the LH2 carrier.

The final decision on the Port of Gladstone channel widths and depths is the purview of GPC and the Regional Harbour Master (RHM). The decision will consider requirements of other potential users at the Fisherman's Landing northern expansion area. Discussions with GPC and the RHM will be progressed through FEED.

4.6 Hydrogen Liquefaction Facility (HLF) – Phase 2

The Phase 2 HLF will involve a scaled-up version of the Phase 1 facility. The Phase 2 HLF development will produce an additional 700 tpd of hydrogen (total 800 tpd).

Power transmission and network services

The HLF Phase 2 power demand is ~560 MW, with intermittent peaks of 600 MW. As previously mentioned, Powerlink was engaged to prepare a SFA, with the preferred option expected to be a double circuit 275 kV connection to Powerlink's Calliope River 275 kV substation.

Water supply and treatment

The estimated raw water demand for the Phase 1+2 HLF is 11,170 ML/year, to support 800 tpd of hydrogen liquefaction.

An assessment of the options for HLF Phase 2 water supply and treatment was conducted as part of the Feasibility Study.

Seawater cooling is expected to reduce the raw water demand for the HLF Phase 2 by about 10,000ML/year when compared with a raw water supply scenario – through the proposed utilisation of seawater cooling at the HLF, the total estimated Phase 2 HLF raw water demand would remain unchanged from Phase 1. The benefits of using seawater for HLF cooling purposes are multiple:

in reducing the quantum of fresh water required, reducing the project's reliability on external water sourcing and providing a large volume stream to comingle a much smaller (but more saline) HPF stream; all whilst incurring only a small incremental cost for water supply.

Wastewater management

The recommendation of the wastewater management assessment for Phase 2 is to discharge ocean outfall. The volume of wastewater for HLF Phase 1+2 is estimated to be 4,569 ML/year. There is the potential for this system to be combined with a seawater cooling circuit if this option is adopted for Phase 2. This would result in wastewater volume being unchanged from Phase 1 (i.e., 571 ML/year).

HLF receiving facilities

The HLF receiving facilities were designed to accommodate Phase 2 flow condition, with minimal changes e.g., opening a parallel metering run in the custody transfer meter and the filtering system. The assessment undertaken suggests that (at a minimum) the assembly should be installed with all piping components and leaving room for future drop-in meter runs to be installed in Phase 2.

In all investigated metering system designs, the flowrates and pressure drops increase slightly in Phase 2, but with minimal impact on upstream compression. A preference for Coriolis metering emerged from the analysis, however ultrasonic metering also has viability. The decision on metering technology will be made during FEED.

4.7 Hydrogen Liquefaction Facility (HLF) – process description

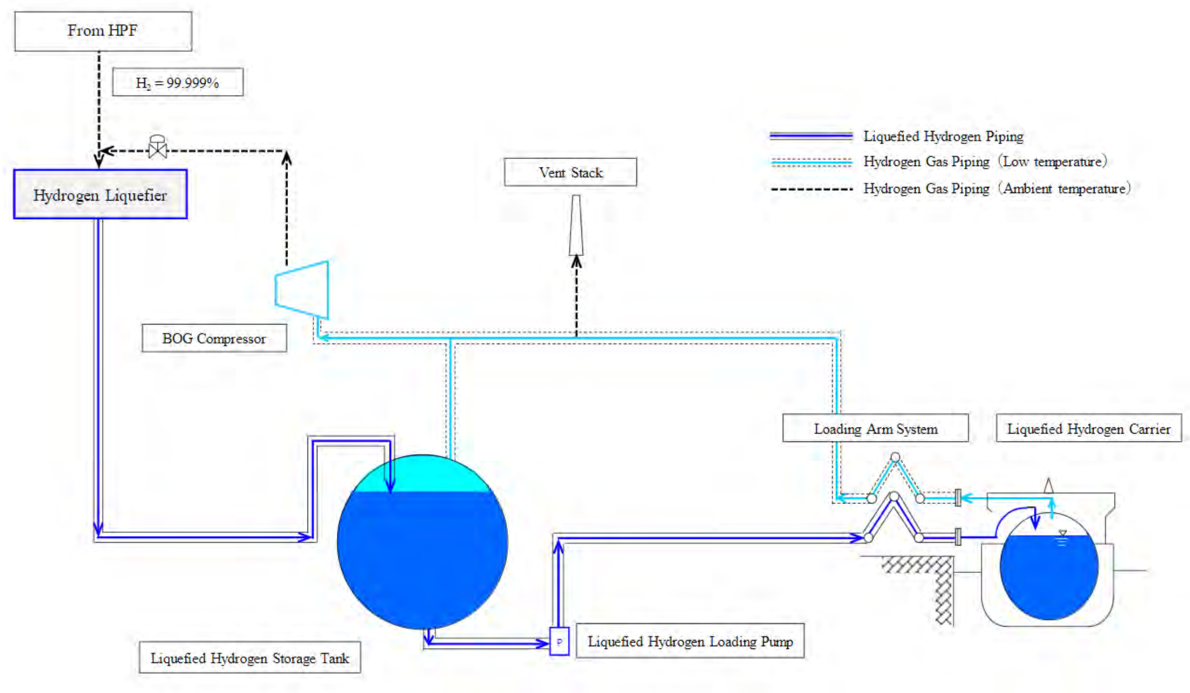
Overview

A high-level process description of the hydrogen liquefaction process and preparation for export / shipping is included below, and involves the key hydrogen processing stages as identified in Figure 30:

- **Hydrogen liquefaction**: Gaseous hydrogen (GH2) enters the liquefier (via pipeline from the HPF) at a pressure of approximately 30Bar and undergoes liquefaction using coolant streams to produce liquefied hydrogen (LH2);
- **Liquefied hydrogen storage**: The liquefied hydrogen produced is stored in the liquefied hydrogen storage tank (LH2 storage tank);
- **Boil-off gas treatment**: Boil off gas (BOG) present in the LH2 storage tank is extracted, compressed to approximately 30Bar in the BOG compressor, and re-liquefied in the liquefier;

  As part of the loading operation, LH2 from the storage tank is loaded onto the liquefied hydrogen carrier ship (LH2 ship) cargo tank through the liquefied hydrogen loading pump (LH2 loading pump) and loading arm system (LAS), and BOG from the ship cargo tank is extracted, compressed in the BOG compressor, and re-liquefied;
- **Loading facilities**: Ship loading facilities will be required to transport LH2 to the cryogenic storage tanks onboard the LH2 Carrier. This will involve LH2 Loading Pipeline, Loading Pumps, and Loading Arm Systems;
- **Vent and flaring facilities**: These facilities will be required to handle emergency discharge of hydrogen (by venting) and mixed refrigerant (MR) (by flaring).

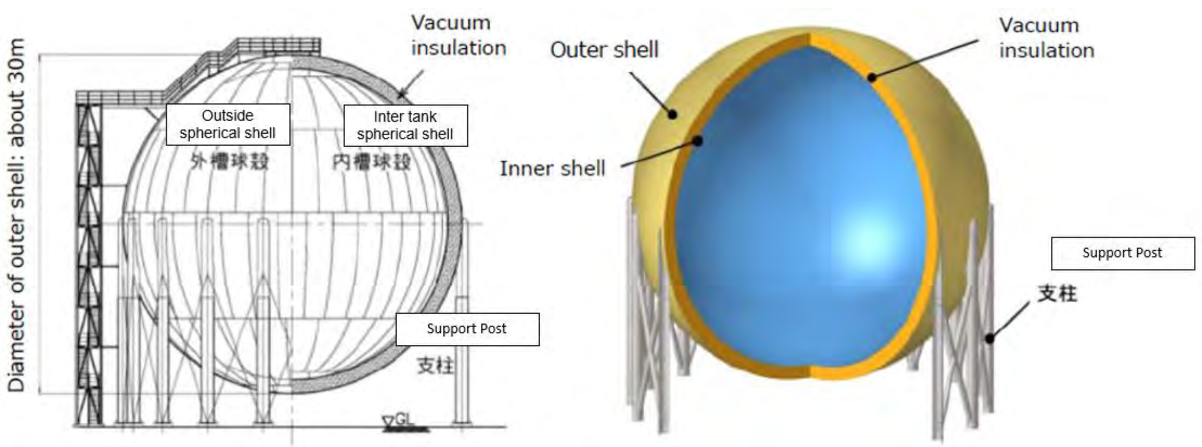
Figure 30: Hydrogen liquefaction process



Liquefied hydrogen storage

LH2 product is stored at low temperature in the LH2 Storage Tanks. LH2 storage tanks are double-walled vacuum insulated tanks, with Perlite[45] installed in the vacuum area to increase insulation capacity.

Figure 31: Liquefied hydrogen storage



Phase 1 LH2 storage

Storage of liquefied hydrogen in Phase 1 of the Project is proposed using five off spherical LH2 storage tanks, each with a capacity of 10,000m^3.

The diameter of the outer shell is approximately 30 metres.

[45] Perlite is an insulating material used in cryogenics.

Phase 2 LH2 storage

Storage of liquefied hydrogen in Phase 2 of the Project is proposed using three off cylindrical LH2 storage tanks, each with a capacity of 50,000m^3.

Technology refinement and design development to support manufacture of these large volumetric tanks is ongoing.

Boil-off gas treatment

Boil-off gas (BOG) treatment of hydrogen is similar in concept to the process involved in LNG production and loading but must be performed at much lower temperatures.

BOG treatment is required for reprocessing of GH2 that is produced as "boil-off" is created when stored in the LH2 Storage tanks, or as a result of preparation for LH2 product loading.

The key piece of equipment involved in BOG reprocessing is the BOG compressor. The BOG compressor is a positive displacement (reciprocating) machine which re-pressurises the BOG stream. The BOG produced remains at cryogenic conditions, so the BOG compressor must be capable of handling and compressing gas at temperatures approaching -253°C.

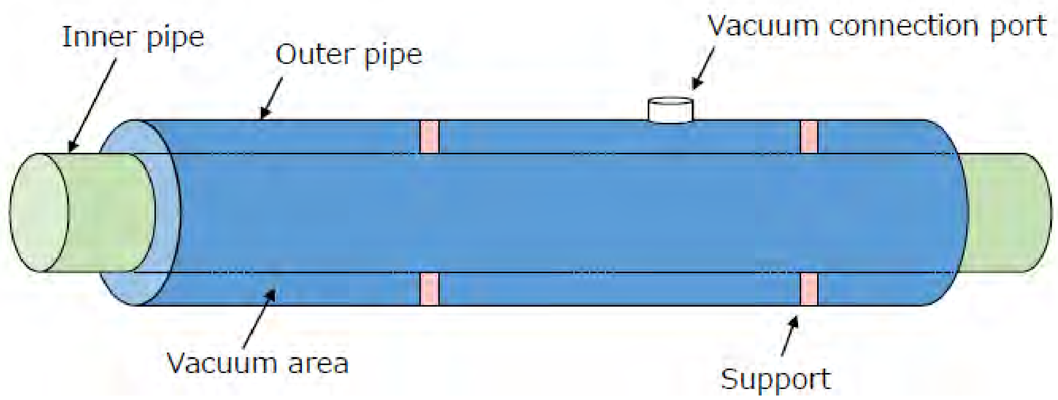
Currently, a large-scale hydrogen gas compressor is under development under a Japanese government-subsidised project, with product development continuing.

Loading facilities

Loading pipeline

A double-walled loading pipeline with vacuum insulation (VI) is essential for pipeline transportation of the LH2 product within the plant area. The inner pipe is vacuum insulated, and multi-layer insulation (MLI) is installed in the vacuum area. Adequate design and installation of the inner pipe supports will be required so as not to introduce excess thermal stresses.

Figure 32: Loading pipeline



Loading pumps

A large scale LH2 pump is also under development.

It is important to note that adequate adoption to LH2 temperature and low viscosity is required.

Loading arm systems

The loading arm is used for loading liquefied hydrogen to the LH2 ship. It is based at the wharf and provides the connection between the LH2 storage tanks and the carrier.

The loading arm will be adequately insulated to prevent liquefaction of oxygen on the surface. Double-walled vacuum insulation is applied for this purpose. Swivel joints (moving parts) will also be adequately insulated. The Emergency Release System (ERS) is designed to keep LH2 release minimum in case of emergency release.

Vent and flaring facilities

Vent and flaring systems are safety-critical plant.

Venting of hydrogen during process upset or emergency response scenarios through elevated vent stack is appropriate due to H2 gas characteristics (lighter than air, dispersal characteristics, etc).

4.8 Cost estimate (Phase 1 & 2)

4.8.1 Cost estimation approach

The approach to the development of the AACE Class 4 cost estimate is outlined in the Cost Estimate Plan.

The required level of estimation confidence is achieved through a combination of the following cost inputs:

- Vendor budget prices
- Technical advisor estimates based on same or similar equipment design/sizes
- Factoring of known bulk / commodity prices

The approach adopted for the Feasibility Study was to develop a sound technical design allowing the development of suitably detailed technical specifications and material take offs (MTOs).

A detailed list of all direct-cost elements of the estimate are provided in the Cost Estimate Plan.

In addition to the determination of the direct costs, indirect costs, owner's costs and contingency were also estimated in line with approach described in the Cost Estimate Plan.

4.8.2 Capital cost estimate

The Capital Cost Estimate provides full details of the Phase 1 and Phase 2 capital costs.

The capital cost estimate (in Australian dollars (AUD)), based on costs as at March 2022, is outlined below. It should be noted that prima facie electrolyser costs have increased since the Concept Study, as a consequence of global supply chain constraints and global geopolitical challenges. Table 24 provides a summary of the total installed cost of upstream scope and collation of midstream cost areas:

Table 24: Upstream and Midstream cost summary

Area	Phase 1	Phase 2 increment	Phase 1+2 combined
Upstream[46]	A$1,181,079,033 **(A$1.18 billion)**	A$5,295,385,748 **(A$5.30 billion)**	A$6,476,464,781 **(A$6.48 billion)**
Midstream[47]	A$2,684,879,252 **(A$2.68 billion)**	A$5,591,250,000 **(A$5.59 billion)**	A$8,276,129,252 **(A$8.28 billion)**
Total	A$3,865,958,285 **(A$3.87 billion)**	$10,886,635,748 **(A$10.89 billion)**	A$14,752,594,033 **(A$14.75 billion)**

Table 25 provides a summary of the total installed costs. The estimate is based on native currencies represented in AUD.

All costs in the estimate that are based on currencies other than the Australian Dollar.

No allowance has been made for variation in the rate of exchange between the estimate date and the placement of purchase orders or contracts. This will be analysed as part of the detailed financial model during FEED.

The estimated total installed cost (TIC) for the base case execution approach (i.e. EPCM) is summarised by major scope area as below. The estimate is based on March 2022 pricing in Australian Dollars (AUD).

Table 25: Total installed costs (TIC) summary

Description	Upstream			Midstream			Total Installed Cost (AUD $MM)		
	Phase 1	Phase 2 increment	Phase 1+2 combined	Phase 1	Phase 2 increment	Phase 1+2 combined	Phase 1	Phase 2 increment	Phase 1+2 combined
Power Supply	46	35	**81**				46	35	**81**
Water Supply & Wastewater Management	22	-	**22**				22	-	**22**
Hydrogen Production Facilities (HPF)	709	3,792	**4,501**				709	3,792	**4,501**
Hydrogen Pipeline & Storage	57	-	**57**				57	-	**57**

46 Upstream encompasses HPF, storage and pipeline

47 Midstream encompasses HLF and shipping

Total Shipping	4	-	**4**	2,682	5,592	**8,273**	2,686	5,592	**8,276**
Indirect & Owner's Costs	344	1,468	**1,812**	89	93	**182**	433	1,561	**1,994**
Total Installed Cost (AUD $MM)	**1,181**	**5,295**	**6,476**	**2,770**	**5,684**	**8,455**	**3,952**	**10,979**	**14,931**

No forward escalation between the estimate date and the settlement of any orders or contracts has been allowed.

The average direct manual labour rate is AUD $90 per hour. Direct manual labour rates were developed around a crew mix based on actual data from projects from Gladstone, as well as Worley's historical data.

A 60-hour work week is assumed for the workforce, comprised of a 10-hour day, six-day work week, with Sunday as the day off.

4.8.3 Operating cost estimate

The Phase 1 Operating Cost Estimate and the Phase 2 Operating Cost Estimate provide full details of all anticipated operating costs.

The major contributors to OPEX are electricity costs for both the HPF and HLF, as well as labour costs, refurbishment costs for the electrolysers and general maintenance of the electrolyser, pipeline and compression units.

Phase 1

The total upstream OPEX is on average $106.29 million/y. The following table outlines the cost area breakdowns for both the HPF and HLF, where the largest contributors to the total HPF OPEX are electricity and electrolyser maintenance and refurbishment.

Table 26: Breakdown of OPEX per cost area

Cost Area	OPEX ($million/y)
Upstream Subtotal	106.29
Midstream Subtotal	102.82
Overall OPEX	**209.11**

Phase 2

The total upstream OPEX is on average $622.10 million/y for the Phase 1+2 development. The following table outlines the cost area breakdowns for both the HPF and HLF, where the largest contributors to the total HPF OPEX are electricity and electrolyser refurbishment.

Table 27: Breakdown of OPEX per cost area – Phase 1+2

Cost Area	OPEX ($million/y)
Upstream Subtotal	622.10
Midstream Subtotal	353.96
Overall OPEX	**976.06**

4.9 Transport and logistics

An important element of ascertaining the feasibility of the Project involved examination of transport and logistics considerations relating to sea transport to the Port of Gladstone and road transport to Aldoga. Potential traffic impacts associated with the Project were also scoped.

The Project engaged a freight forwarding and logistics specialist (DB Schenker) to undertake an initial (mainly desktop) logistics study to examine the transport of modules to the HPF (near Aldoga) from potential manufacturing locations in Asia.

The assessment undertaken showed clear paths for transport to site from probable import points, with no major restrictions that would affect the Project during construction. Further refinement of transport and logistics considerations will be undertaken in parallel to engineering and design activities during FEED. This includes potential work relating to modularisation of the HPF.

Oversize modules

The target transport envelope was based around the maximum module sizes nominated by electrolyser vendors, in recognition that electrolyser components constitute the vast majority of material to be transported. The specifications were 27.5m maximum length, 6.05m maximum width, 5.10m maximum height, and 101.9 tonnes maximum weight. The study examined:

Sea transport from Asia

Asia was chosen as the base/reference given that nearly all vendors source base components from Asia. No perceived limitations were identified with respect to the sea transport of nominated modules.

Offloading at the Port of Gladstone and road transport to Aldoga

All smaller and container sized modules can be accommodated at the current container and over-sized goods port berth in Gladstone (Auckland Point #4 berth), with this facility being served by a short-term laydown yard.

Containerised freight

As shipping containers are not currently accepted at the Port of Gladstone, the recommendation was made to use the Port of Brisbane and road transport to the site along established transport corridors.

Traffic impacts – early assessment guidance

A TIA will be undertaken for the Project during FEED, with the expectation being that construction traffic will have the greater potential to impact the existing road network (rather than operational traffic, which is anticipated to have minimal impact) for the entire Project.

5 Financial analysis

The financial and commercial analysis for the CQ-H_2 Project considered:

- Cost structures
- Revenue models
- Debt financing options
- Future grant funding opportunities
- Tax and accounting implications as they apply to possible financing structure options and the optimisation of the treatment of government grants.

The output of the analysis was used to assess the financial and commercial viability of the Project and is based on information and assumptions available as at 26 May 2022.

The analysis assessed two project joint venture structures formally proposed by the Consortium which have regard to the possible segregation of the Project's supply chain. The Project structure options are listed below:

- **Structuring Option 1:** HPF, Hydrogen Pipeline, HLF and Shipping & Receiving components are structured as four separate Incorporated Joint Ventures (IJVs) ("Option 1")
- **Structuring Option 2:** HPF and Hydrogen Pipeline are combined into one IJV, while HLF and Shipping & Receiving components are structured as two separate IJVs ("Option 2").

The financial and commercial analysis included the development of a financial model. The financial model includes financial statements, as well as key project metrics including Levelised Cost of Hydrogen (LCOH), Net Present Value (NPV), and Internal Rate of Return (IRR) for the two structuring options being considered.

The model considers three scenarios, the Base Case, Optimised Case and Stretch Case. The Base Case was developed using the set of baseline assumptions developed and provided by the Technical Advisor. The Base Case reflects the information available at present and the analysis in this report focuses on the Base Case outputs.

Two sensitivities were developed in order to evaluate likely and potential improvements and efficiencies in the hydrogen sector. These sensitivities were labelled Optimised and Stretch cases. The Optimised and Stretch cases were developed by application of incremental adjustments to the Base Case's key operating, capital cost and funding assumptions. The Optimised Case takes into consideration expected developments and cost efficiencies in the renewable hydrogen market, while the Stretch Case considers a best-case scenario under which further cost efficiencies are achieved.

As Phase 1 and 2 were assessed as two stand-alone projects, it should be noted the Phase 2 analysis represents the Phase 2 Incremental project costs and production as incremental to Phase 1. The Hydrogen Pipeline is assumed to be constructed in Phase 1 and continues to operate until the end of the Project without additional capital or operating costs incurred in Phase 2. Therefore, there is no Hydrogen Pipeline related costs presented for Phase 2 Incremental.

5.1 Summary

The Base Case reflects the current costs estimates as at 26 May 2022. The Levelised Cost of Gaseous Hydrogen (LCOGH) reflects the pre-tax cost per kg of gaseous hydrogen delivered to the HLF without taking grants into consideration as at 1 July 2021. If the Project is able to achieve the targeted efficiencies assumed under the Optimised and Stretch scenarios the LCOGH will reduce as per the table below.

Table 28: Levelised cost of gaseous hydrogen (LCOGH)

LCOGH pre-tax	Base	Optimised	Stretch
Phase 1 *(without grants)*	\$5.76	\$4.89	\$4.65
Phase 2 Incremental *(without grants)*	\$4.25	\$3.38	\$2.79

The Levelised Cost of Liquefied Hydrogen (LCOLH) reflects the pre-tax cost per kg of liquefied hydrogen delivered to Japan excluding grants.

Table 29: Levelised cost of liquefied hydrogen (LCOLH)

LCOLH pre-tax without grants	Base	Optimised	Stretch
Phase 1			
LCOLH - HPF and Hydrogen Pipeline contribution	\$7.31	\$6.20	\$5.90
LCOLH - Shipping & Receiving contribution	\$11.88	\$11.31	\$11.09
Phase 1 - Total Project LCOLH	\$19.19	\$17.51	\$16.99
Phase 2			
LCOLH - HPF and Hydrogen Pipeline contribution	\$4.56	\$3.63	\$2.99
LCOLH - Shipping & Receiving contribution	\$3.40	\$3.11	\$3.00
Phase 2 - Total Project LCOLH	\$7.95	\$6.74	\$5.99

In making the estimates above, there were a number of general assumptions underpinning the analysis. These are summarised in the table below.

Table 30: General assumptions

Description	Assumption
Discount date	1 July 2021
Discount rate	Pre-tax, real: 6.00% Pre-tax, nominal: 8.23% Post-tax, real: 4.20% Post-tax, nominal: 5.76%
Escalation rate	FY2022: 2.70% FY2023 onwards: 2.10%
Construction period (including expenditure start dates)	Phase 1: 1 Jul 2022 – 30 Nov 2026 Phase 2: 1 Jul 2026 – 30 Nov 2026
Operation period	Phase 1: 1 Dec 2026 – 30 Nov 2060 (34 years) Phase 2: 1 Dec 2030 – 30 Nov 2060 (30 years)
Cash flow timing	Mid period
Periodicity for analysis	Annual

5.2 Project Costs

Table 31 and Table 33 below summarise the whole of life (34 years for Phase 1, 30 years for Phase 2) project costs in Real, Nominal and Present Value (PV) terms for the Base scenario for Phase 1 and Phase 2 Incremental. The operating cost average per annum in Real, Nominal and PV terms are presented in Table 32 and Table 34. The PV was calculated using a pre-tax, nominal discount rate of 8.23 percent by discounting the nominal cash flows to 1 July 2021.

Table 31: Whole of Life Project Costs – Base Phase 1 ($ Million)

Whole of Life Project Costs Base Phase 1	$FY2022 Real AUD (million)	$Nominal AUD (million)	$PV AUD (million)
Hydrogen plant			
Initial capital costs	$1,101	$1,182	$870
Lifecycle capital cost	$86	$126	$29
Electricity costs	$3,148	$5,111	$969
Fixed operating costs	$79	$124	$28
Variable operating costs	$211	$339	$66
Total Hydrogen plant	$4,626	$6,882	$1,962
Hydrogen pipeline			
Initial capital costs	$80	$86	$63
Lifecycle capital cost	-	-	-
Electricity costs	-	-	-
Fixed operating costs	$15	$23	$5
Variable operating costs	-	-	-
Total Hydrogen pipeline	$94	$109	$68
Total Shipping & Receiving	^6,115	$8,356	$3,296
Total Capex	**$3,952**	**$4,229**	**$3,182**
Total Opex	**$6,882**	**$11,119**	**$2,144**
Total Costs	**$10,834**	**$15,348**	**$5,326**

Table 32: Operating Costs Average Per Annum – Base Phase 1 ($ Million)

Operating Costs Average Per Annum Base Phase 1	$FY2022 Real AUD (million)	$Nominal AUD (million)	$PV AUD (million)
Hydrogen plant			
Electricity costs	$93	$150	$29
Fixed operating costs	$2	$4	$1
Variable operating costs	$6	$10	$2
Total Hydrogen plant	$101	$164	$31
Hydrogen pipeline			
Electricity costs	-	-	-
Fixed operating costs	-	$1	-
Variable operating costs	-	-	-
Total Hydrogen pipeline	-	$1	-
Total Shipping & Receiving	$101	$163	$31

Total Costs	**$202**	**$327**	**$63**

Table 33: Whole of Life Project Costs – Base Phase 2 Incremental ($ Million)

Whole of Life Project Costs Base Phase 2 Incremental	$FY2022 Real AUD (million)	$Nominal AUD (million)	$PV AUD (million)
Hydrogen plant			
Initial capital costs	$5,295	$6,176	$3,310
Lifecycle capital cost	$653	$1,035	$179
Electricity costs	$17,448	$29,295	$4,655
Fixed operating costs	$267	$447	$71
Variable operating costs	$221	$369	$60
Total Hydrogen plant	$23,884	$37,322	$8,274
Total Shipping & Receiving	$15,089	$22,316	$6169
Total Capex	**$11,540**	**$13,663**	**$7,094**
Total Opex	**$27,432**	**$45,975**	**$7,349**
Total Costs	**$38,972**	**$59,638**	**$14,443**

Table 34: Operating Costs Average Per Annum – Base Phase 2 ($ Million)

Operating Costs Average Per Annum Base Phase 2	$FY2022 Real AUD (million)	$Nominal AUD (million)	$PV AUD (million)
Hydrogen plant			
Electricity costs	$582	$976	$155
Fixed operating costs	$9	$15	$2
Variable operating costs	$7	$12	$2
Total Hydrogen plant	$598	$1,004	$160
Hydrogen pipeline			
Electricity costs	-	-	-
Fixed operating costs	-	-	-
Variable operating costs	-	-	-
Total Hydrogen pipeline	-	-	-
Total Shipping & Receiving	$316	$529	$86
Total Costs	**$914**	**$1,533**	**$245**

5.3 Scenario Assumptions

The Base Case provides the cost input at this point in time. The Project expects to identify efficiencies as the renewable hydrogen sector and market evolves. These efficiencies are expected to manifest as improved capital costs and operational efficiencies. In particular, detailed analysis was undertaken into the potential cost and operational efficiencies for the HPF and the Hydrogen Pipeline. This analysis is reflected in the Optimised Case which represents the improvements that are expected in the hydrogen industry. The Stretch Case represents the anticipated best-case scenario.

The table below outlines the assumptions which have been adjusted for each of the Base, Optimised and Stretch scenarios. There were no grants included in the analysis. The capital optimisation parameters (including electrolyser, non-electrolyser capex and contingency reduction) are presented as percentage reductions of the Base Case's initial capital costs for each individual phase, while power and other assumptions are presented in absolute values. As a result of the extension of membrane life from the Base Case to the Optimised and Stretch Case for the membrane component provided by Vendor 1 the frequency of replacement was reduced from two to one for both Phase 1 and Phase 2.

Table 35: Scenario Assumptions

Parameters	Unit	Base Phase 1	Optimised Phase 1	Stretch Phase 1	Base Phase 2	Optimised Phase 2	Stretch Phase 2
LCOGH Output	**$AUD/kg**	**$5.76**	**$4.89**	**$4.65**	**$4.25**	**$3.38**	**$2.79**
Initial Capital Cost							
Grants	$FY2022 Real AUD (million)	-	-	-	-	-	-
Electrolyser Capex Optimisation (HPF)	% reduction of Base Case Electrolyser Capex	-	15%	20%	-	10%	25%
Non-Electrolyser Capex Optimisation (HPF)	% reduction of Base Case Initial Capex	-	15%	20%	-	10%	20%
Contingency Reduction (HPF + Pipeline)	% reduction of Base Case Initial Capex	-	7%	10%	-	5%	10%
Total Initial Capex (HPF + Pipeline) after adjustments	$FY2022 Real AUD (million)	$1,181	$933	$843	$5,295	$4,501	$3,547
Power Assumptions							
Power Price	$FY2022 Real AUD /MWh	$44.35	$44.35	$44.35	$38.00	$33.00	$28.00
TUOS	$FY2022 Real AUD /MWh	$6.12	$2.50	$2.50	$7.23	$2.50	$2.50
Weighted Average Electrolyser Power Demand	KWh/kg	49.72	49.72	49.72	47.80	47.80	47.80
Weighted Average Electrolyser Efficiency Reduction	% reduction per year	1.11%	0.95%	0.95%	1.32%	0.87%	0.87%
BoP Power Demand	MW	7.50	7.50	7.50	70.79	73.18	40.00
Others							
HPF and HLF Utilisation	%	90.4%	94.7%	96.8%	94.1%	97.3%	97.3%
Membrane Life (TkUCE)	Hours	70,000	105,120	105,120	70,000	105,120	105,120

5.4 Tax and Accounting Considerations

The tax and accounting analysis firstly considered the alternative structuring vehicles that could be used for the Project as described in Table 36 below. Based on the information in the table, the analysis an IJV was identified as the preferred structuring vehicle. The analysis subsequently considered the key tax and accounting considerations relevant to the structuring of the Project using IJVs under Structuring Options 1 and 2 (excluding Shipping & Receiving). The tax and accounting findings of the structuring analysis were incorporated into the financial model.

5.4.1 Project Vehicles

Three alternative structuring vehicles were considered for the Project, these are summarised in the table below.

Table 36: Key Alternative Structuring Vehicles

Key Issue	Priority	Unincorporated Joint Venture (UJV)	IJV	Trust
Grant and debt funding at the joint venture level?	High	No	Yes	Yes
Grant funding non-assessable upfront?	High	No	Likely	Complex
Tax exempt entities (e.g. Stanwell) can own >20% equity?	High	N/A	Yes	No
Taxation of project income at the tax rate of the Consortium Partner?	High	Yes	No	Yes
Separate legal entity?	High	No	Yes	Yes
Consolidation of joint venture on balance sheet?	High	Yes	Depends	Depends
Tax losses available to Consortium Partners in year incurred?	Medium	Yes	No	No
Consortium Partners jointly and severally liable for income tax and Goods and Services Tax (GST) debts of the Project?	Medium	No	No	No
Offtake owned by Consortium Partners?	Medium	Yes	No	No
Option to elect to form an income tax consolidated group?	Low	No	Yes	No
Tax deferred distributions?	Low	No	No	Yes
Tax compliance obligations at the JV level?	Low	No	Yes	Yes

Key Favourable outcome Unknown / neutral outcome Unfavourable outcome

Based on this analysis, an IJV was identified as the preferred structure for the Project. An IJV is the preferred structure as (amongst other considerations) it will allow Consortium partners to invest in their preferred components of the value chain. It is also preferred from a legal and regulatory perspective. The Tax and Accounting Report includes for further details on tax and accounting considerations relevant to each of these vehicles.

5.4.2 Project Structures

The analysis has assessed two project joint venture structures which have regard to the possible segregation of the Project's supply chain. The Project structure options are listed below:

- **Structuring Option 1:** HPF, Hydrogen Pipeline, HLF and Shipping & Receiving components are structured as four separate IJVs ("Option 1")
- **Structuring Option 2:** HPF & Hydrogen Pipeline (combined), HLF and Shipping & Receiving components are structured as three separate IJVs ("Option 2").

Table 37 below includes details on supply chain considerations relevant to structuring Options 1 and 2.

Table 37: Key Considerations for Segregation of Supply Chain

Key considerations	Segregation of supply chain	
	Option 1	Option 2
Commercial	• Suitable structure if HPF, Hydrogen Pipeline and HLF are needed to be built as standalone assets commercially (and not dedicated only to CQ-H2) and each asset requires arm's length arrangements from a bankability perspective • Clear ownership structure for each asset • Separate IJVs provides maximum flexibility for Consortium Partners (and other investors) to invest in and exit the different components of the value chain at any stage of the Project • Allows the pipeline to become part of a regional common user infrastructure solution if this is demanded by local industry/government (social licence benefits)	• Suitable commercial structure based on gas industry precedents, given the Hydrogen Pipeline can be structured as a dedicated asset to meet HLF requirements and involves delivering the same product form (gaseous hydrogen) to HLF • Practically precludes the pipeline becoming part of a regional common user infrastructure approach.
Financing	• HLF has a unique operational risk profile (e.g. uninterrupted continuous operations) so a separate IJV may be suited to provide delivery guarantees, limit partner liabilities and meet the overseas investment requirements • Need to raise non-recourse and or limited recourse project finance for individual assets with dedicated cashflows from S&P Investment Grade Offtake counterparties	• If the Hydrogen Pipeline is dedicated to HPF, financing these assets under a single integrated IJV is a structure known to financiers from gas projects. • If the Hydrogen Pipeline is not dedicated to HPF and is part of a regional common user infrastructure solution, financing the HPF and the Hydrogen Pipeline in a single IJV might not have the same benefits given the commercial terms involved with various project parties in the region. • This will need further discussion with potential financiers. There will still be a need to raise non-recourse and or limited recourse project finance for individual assets with dedicated cashflows from S&P Investment Grade Offtake counterparties.

Tax	• Unlikely to result in any adverse tax consequences for Phase 2 investment in different components of the supply chain and Consortium Partners wanting to exit the Project	• Losses generated by HPF could be offset against taxable income of the Pipeline
Accounting	• Need to consider whether IJVs meet the accounting definition of Joint Arrangements (joint control only when unanimous consent etc.) for accounting purposes	• Need to consider whether IJVs are Joint Arrangements for accounting purposes

5.4.3 Phase 2 Structuring Considerations

It is expected that Phase 2 of the Project will occur either within the existing IJVs incorporated as part of Phase 1, or new IJV(s) will be incorporated for the Phase 2 HPF.

In addition to legal and commercial considerations, the structuring of Phase 2 will depend on the tax profile of investors that may want to participate in Phase 2 (i.e. new passive investors), and also the anticipated tax profile of the Phase 2 operations, including capital allowances and timing of any tax losses that may be generated in Phase 1. It will be important that the Project maintains flexibility for Phase 2 investment while mitigating transaction-related taxes (e.g. stamp duty and income tax) associated with this investment.

Consequently, the structuring of Phase 2 for the Project should be considered in further detail once the likely profile of Phase 2 investors is known, and further refinements of the financial model are made in the Front-End Engineering Design (FEED) stage.

5.4.4 Structuring Outcomes

The NPV difference between structure Option 1 and Options 2 is unlikely to be significant enough of itself to cause Option 2 to be the preferred structure given the broader commercial, accounting and tax drivers for the Project. It should be noted that the tax and accounting considerations do not consider Shipping & Receiving as it was excluded this from the tax and accounting analysis on the basis that these activities would be undertaken by a foreign entity.

Please refer to the Tax and Accounting Report for further detail, including the detailed tax and accounting findings for Option 1 and Option 2.

5.5 Outcomes of Financial Modelling

This section presents the levelised cost outcomes of the CQ-H_2 Project based on the current set of assumptions, as assessed using the Project's Financial Model. The analysis considers the capital costs and operating costs, for the Project. The analysis was conducted for a 34-year evaluation period (Fiscal Year (FY) 2023 – FY2061) for Phase 1 and a 30-year evaluation period (FY2027 - FY2061) for Phase 2.

5.5.1 Levelised Costs

The levelised costs were calculated using a pre-tax, real discount rate of 6 percent, as at 1 July 2021. It should be noted that Phase 1 and Phase 2's LCOH values represent the levelised costs based on the stand-alone costs and production of the individual phase and should not be added together. The levelised cost of both phases combined will fall between the levelised costs of Phase 1 and Phase 2.

The Levelised Cost of Gaseous Hydrogen (LCOGH) reflects the pre-tax cost per kg of gaseous hydrogen delivered to the HLF without taking into consideration grants. Table 38 below summarises the LCOGH based on the costs associated with the HPF and Hydrogen Pipeline for each scenario.

Table 38: LCOGH for HPF and Hydrogen Pipeline without grants (AUD/kg)

LCOGH pre-tax without grants	Base	Optimised	Stretch
Phase 1	$5.76	$4.89	$4.65
Phase 2 Incremental	$4.25	$3.38	$2.79

The main cost components which contribute to the LCOGH are electricity costs and initial capital costs. The breakdown of the LCOGH for the Base Case for Phase 1 and Phase 2 Incremental by cost category are shown in Figure 33 and Figure 34 below.

Figure 33: Breakdown of Pre-tax LCOGH without Grants – Base Phase 1

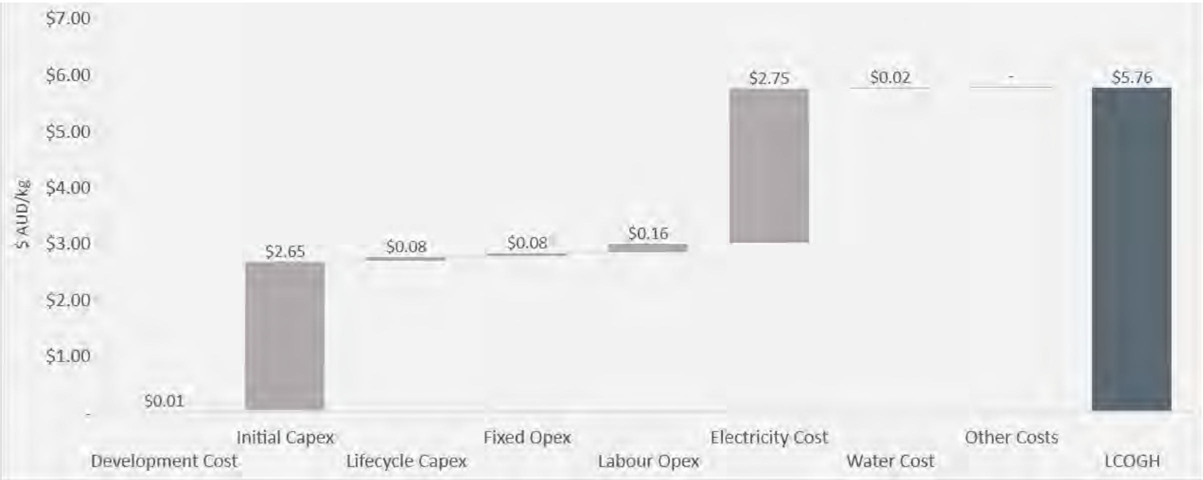
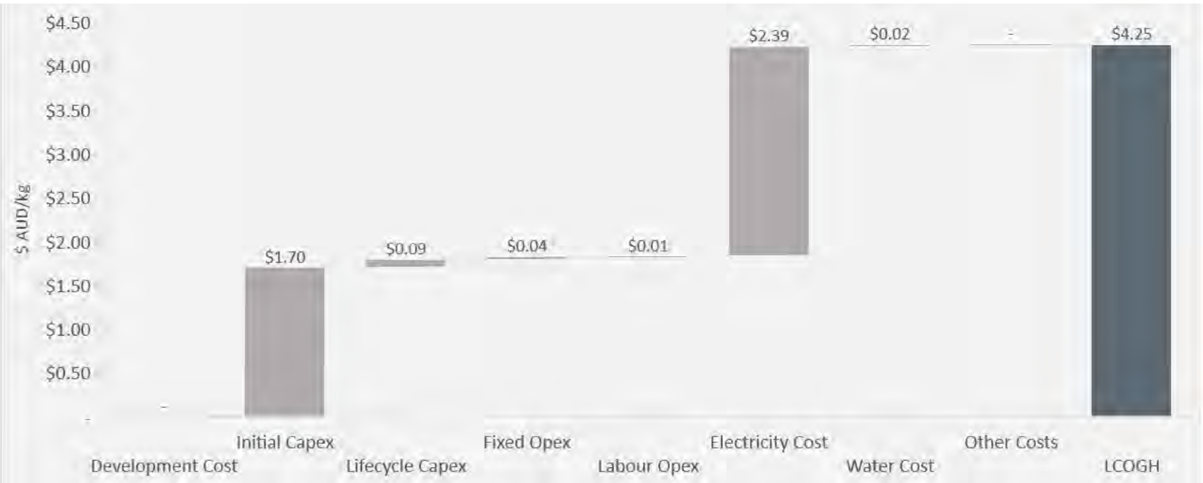


Figure 34: Breakdown of Pre-tax LCOGH without Grants – Base Phase 2 Incremental



The Levelised Cost of Liquefied Hydrogen (LCOLH) reflects the pre-tax cost per kg of liquefied hydrogen delivered to Japan excluding grants. This measure takes into consideration the losses incurred through liquefaction and shipping and therefore the volume of hydrogen is lower than that used in the LCOGH calculation.

Table 39 below summarises the LCOLH for each component in the supply chain for each scenario.

Table 39: LCOLH by Supply Chain Components (AUD/kg)

LCOLH pre-tax without grants	Base	Optimised	Stretch
Phase 1			

LCOLH - HPF and Hydrogen Pipeline contribution	$7.31	$6.20	$5.90
LCOLH – Total Shipping contribution	$11.88	$11.31	$11.09
Phase 1 - Total Project LCOLH	$19.19	$17.51	$16.99
Phase 2			
LCOLH - HPF and Hydrogen Pipeline contribution	$4.56	$3.63	$2.99
LCOLH – Total Shipping contribution	$3.40	$3.11	$3.00
Phase 2 - Total Project LCOLH	$7.95	$6.74	$5.99

5.5.2 Discount rate sensitivity

The pre-tax real discount rate applied across all scenarios in the model is 6.0 percent, with the discount date as at 1 July 2021. Table 40 and 41 below compare the impacts on the total LCOGH and LCOLH by adjusting the discount rate by +/- 100 basis points. This analysis shows the LCOGH/LCOLH can be very sensitive to the discount rate.

Table 40: Discount Rate Sensitivity on Total LCOGH without Grants (Base Case)

Without grants	Pre-tax real discount rate = 5.0%	Pre-tax real discount rate = 6.0%	Pre-tax real discount rate = 7.0%
Phase 1	$5.45	$5.76	$6.10
Phase 2	$4.06	$4.25	$4.45

Table 41: Discount Rate Sensitivity on Total LCOLH without Grants (Base Case)

Without grants	Pre-tax real discount rate = 5.0%	Pre-tax real discount rate = 6.0%	Pre-tax real discount rate = 7.0%
Phase 1	$17.77	$19.19	$20.71
Phase 2	$7.52	$7.95	$8.42

6 Commercial feasibility

The CQ-H_2 Project offtake is predicated on the export market supply arrangements with hydrogen end users and refuelling companies in Japan. Liquid hydrogen will be used as a hydrogen carrier and transported via a liquid hydrogen ship from the Port of Gladstone to a Port in Japan. Liquid hydrogen in Japan will have direct end use in transportation while a substantial volume will be converted to gaseous hydrogen and is expected to have end-use in power generation, heavy industry including steel production.

As part of its Green Growth Strategy Through Achieving Carbon Neutrality in 2050 (announced in December 2020), Japan is aiming to shift the source of hydrogen and fuel cells from fossil fuels to renewable energy. Japan plans to expand its hydrogen market from the current two million tons per year to three million tons per year by 2030 and 20 million tons per year by 2050. The country is highly focused on securing access to hydrogen feedstocks from other global markets including Australia.

Following on from such policies, the developments in the future hydrogen demand market and funding opportunities in Japan have a significant linkage with the underlying offtake assumptions for the CQ-H_2 Project and its commercialisation strategy. There are also dependencies within the potential offtake models, grants and concessional debt financing strategies and project structure options that will influence the overall commercial structure and drive the financial outcomes of the Project. This includes the grant funding opportunities like CQ-H2 Hydrogen Hub funding and GIF that are expected to significantly improve the commercial viability of the Project.

The Consortium includes one of Japan's largest power utilities (Kansai Electric Power Company) and Iwatani Corporation, a leading player in hydrogen refueling station market in Japan, who are expected to be potential hydrogen offtakers for the first phase of the project. The Project's phasing and volumes are specifically designed to meet identified demand for the power generation sector in the Kobe-Kansai region and the hydrogen refueling demand in other areas in Japan. Securing exclusivity on offtake for the Phase 1 and the later phases of the project will be a condition for moving beyond the FEED stage and will assist in de-risking the cashflows of the Project and to achieve non-recourse or limited recourse commercial funding from any bank.

6.1 Potential Offtake Structures

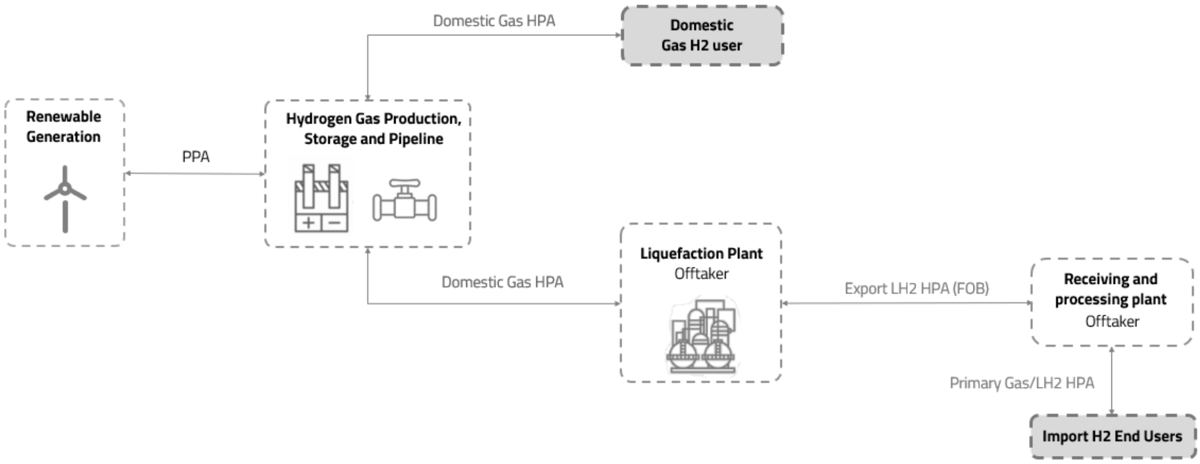
The Feasibility Study assessed two potential offtake structures for the sale of hydrogen to Japan, integrating the various upstream and downstream assets for Phase 1. The upstream activities include gaseous hydrogen production, compression, transportation via pipeline and storage to the liquefaction facility. The midstream activities include liquefaction at port, transportation via pipeline and loading to the liquefied hydrogen carrier and shipping the product to the port in Japan. Downstream activities include unloading from the ship, handling, storage, processing (conversion to gaseous form) and further transportation to end user locations.

The commercial structure developed for Phase 1 will form the foundation for the Project and will need to have compatibility to integrate the future Phase 2 offtake capacity and its requirements. The commercial arrangements for Phase 1 are expected to be short-term and will align with Phase 2 pricing structure, which is expected to be on a blended price basis incorporating Phase 1 and Phase 2 capacities.

6.1.1 Offtake Structure 1 – Similar to a Liquefied Natural Gas (LNG) Integrated Structure

Offtake Structure 1 is summarised in the figure below.

Figure 35: Offtake Structure 1



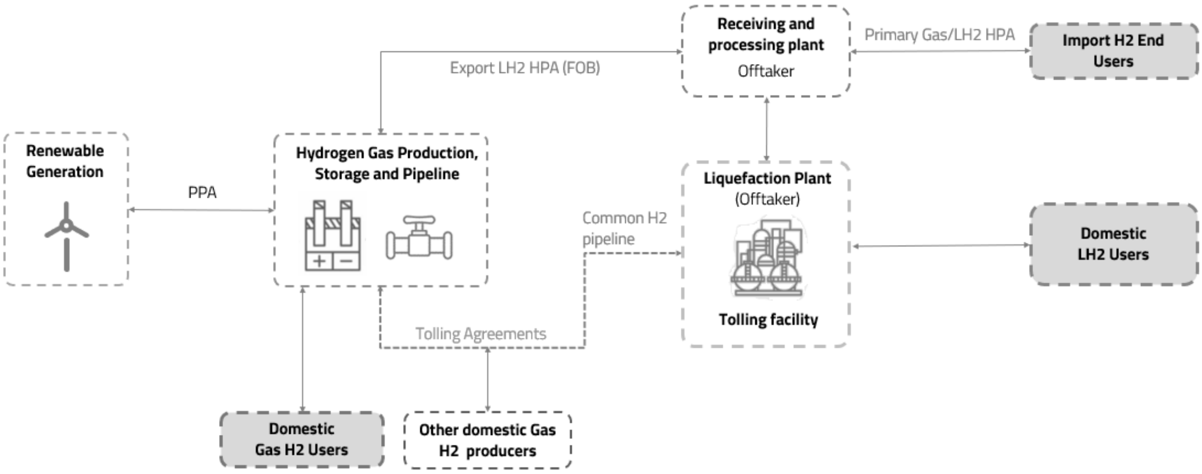
Under this structure:

- The HPF, compression facility and the Hydrogen Pipeline will work under an integrated commercial SPV structure to deliver the gaseous hydrogen to the liquefaction facility;
- The HLF will likely be owned by the Australian subsidiary (AJSPV) of a Japanese entity (JSPV);
- The HPF will have a domestic Hydrogen Gas Sales Agreement (HGSA) with the AJSPV, owner of HLF;
- There would be a further offtake agreement between JSPV and end users and hydrogen suppliers in Japan;
- There would be a liquid hydrogen supply agreement between the liquefaction facility (AJSPV) and the receiving and processing facility in Japan (JSPV), accompanied by a shipping arrangement to deliver the liquid hydrogen in Japan;
- There may an opportunity to supply gaseous hydrogen to domestic offtakers. This is in early exploratory stages;
- There will also be a hydrogen gas transportation agreement (HGTA) between HPF and HLF to deliver the gaseous hydrogen to the liquefaction facility. These agreements would be further developed in the FEED stage;
- JSPV will own the receiving, storage, and processing facilities and JSPV in turn will secure a primary HPA with the end users in Japan;
- The liquefaction facility is solely dedicated to the CQ-H_2 Project and is a critical part of the commercial structure and the supply chain. The liquefication facility will have an export HPA with the JSPV;
- The potential end users of the hydrogen in Japan for Phase 1 of the Project are currently expected to be Kansai Electric for their use in domestic power generation and Iwatani Corporation for use in domestic hydrogen refuelling stations. These offtake opportunities would be further explored in the FEED stage;
- The offtake structure could be set up as an integrated commercial structure under multiple joint ventures, to reflect the ownership interests of the Consortium Partners in the supply chain and overall separation of assets with arms-length commercial contracts.

6.1.2 Offtake Structure 2 – Similar to a LNG Tolling Structure

Offtake Structure 2 is summarised in the figure below.

Figure 36: Offtake Structure 2



Under this structure:

- The HPF has a tolling arrangement with the HLF (AJSPV). A direct HPA with shipping arrangements with the receiving, storage and processing facility (JSPV) which in turn will secure a primary HPA with the end users in Japan;
- Under the tolling structure, the liquefaction plant is financed outside of the CQ-H_2 Project as a separate asset and provides liquefaction as a service to the CQ-H_2 Project and other domestic hydrogen gas producers;
- There is no gas HPA between HPF and HLF.

6.1.3 Advantages and Disadvantages of Offtake Structures

Some of the key commercial advantages and disadvantages are highlighted in Table 42 below.

Table 42: Offtake Structures Advantages and Disadvantages

Offtake Structure	Advantages	Disadvantages
Offtake Structure 1 – Similar to an LNG Integrated Structure	• Known and commonly used structure familiar with offtakers, investors and lenders within LNG sector • Aligns with overall project JV structure, Consortium Partners can hold ownership interests across the supply chain – downstream HPF as well as midstream HLF • Similar structure can be replicated in Phase 2 once Phase 1 is established	• Multiple offtake agreements within supply chain are needed to create a bankable structure • Scale of liquefaction is limited to the CQ-H2 Project hydrogen production capacity, economies of scale are needed for liquefaction especially in Phase 2 without grant funding support •
Offtake Structure 2 – Similar to an LNG Tolling Structure	• Provides scale allowing external demand from hydrogen producers and investors to invest and benefit from the liquefaction plant • No price or market risk for the project investor	• A direct offtake agreement with international entity might be needed. May require additional domestic offtakers to be signed up to make it commercially viable • Financing as a standalone asset for liquefaction will be need for it to be commercially viable • Potentially different tax and accounting regime for the HPF owner to sell into domestic and international markets • Dedicated export facility for Japan reduces the key benefit of a tolling structure

Based on this initial offtake structure options analysis and considering the limitations in a tolling arrangement, the Consortium has indicated its preference for the integrated offtake structure 1 for the downstream facilities, HPF and HLF. The Consortium will continue to assess the commercial, legal, tax and accounting considerations of this offtake structure as well as ensuring alignment from a debt financing perspective.

6.2 Status of Offtake Discussions

The potential offtake arrangements of the CQ-H_2 project will depend on the various funding options available mainly for the liquefaction facility, which is the likely offtaker for the production facility. The funding structure will be determined by the level of government funding support that might be available for the project to make the offtake pricing commercially attractive for end use in Japan, to bring it in line with their policy targets.

The ongoing offtake discussions currently indicate that the Phase 1 offtake terms would be driven by a short-term offtake arrangement with the Japanese Consortium until 2030, which will be subsequently integrated into rolling offtake agreements post 2030. The intention is to blend the Phase 1 pricing with Phase 2 pricing allowing the Phase 1 offtakers to share the pricing benefits through the economies of scale achieved through the larger Phase 2 project.

6.3 Commercialisation Pathway

The commercialisation of the CQ-H_2 Project involves work on various work programs in parallel to confirm the readiness and viability of commercial arrangements to facilitate a Final Investment Decision (FID) by the Consortium. The work programs involve:

- Securing local community acceptance, regulatory approvals and managing risks pertaining to construction of a major project;
- Establishing exclusivity to potentially enter into short-term rolling agreements with the offtakers. The offtake volumes are currently designed to meet identified demand for the power generation sector in the Kobe-Kansai region in Japan. However, alternative offtake options that support the overall economics for project expansion and additional supply chain requirements are being explored. Securing exclusivity for offtake will be a condition for moving beyond the FEED stage;
- Development of the Joint Venture (JV) structure with the Consortium Partners to ascertain the involvement of partners as asset owner / operator / developer across the supply chain from production to liquefaction and shipping. This will include detailed assessment of structuring options for IJV structures, and their taxation and accounting considerations given the Consortium Partners preferences for particular roles in the supply chain;
- Further refinement of the financial model, confirmation of capital structure comprising debt, equity and grant funding sources;
- Establishing binding agreements for land, port and wharf facilities capable of accommodating docking and loading facilities;
- Establishing binding agreements for land for production and liquefaction facilities within the Gladstone State Development Area (GSDA);
- Establishing binding water supply agreements for electrolysis and cooling at production and liquefaction facilities;
- Undertaking detailed engineering design and improving cost accuracy (Class 3);
- Establishing renewable energy supply and electricity infrastructure capable of delivering the required energy for production and liquefaction;
- Establishing pipeline agreement for transportation of gaseous hydrogen via pipeline;
- Assessing the export market policy requirements to determine the long-term demand for hydrogen and ascertaining the production and supply chain investments are fit for purpose to meet the scale of export demand.

The Consortium has developed a costed pathway to reach FEED and FID. This pathway to FID will build on the Feasibility Study work and rigorously test the Project’s technical, financial and commercial viability for hydrogen production, storage and liquefaction to provide strategic investment entry and exit options for the Consortium Partners.

7 Risk analysis and risk management plan

7.1 Risk management approach

Stanwell seeks to actively manage all responses to its risk environment and acts, where necessary, to ensure that risks are contained at acceptable levels, consistent with Stanwell's risk appetite outlined in Stanwell's Board approved Risk Appetite Statement. This statement incorporates systems, structures, processes and people that identify, measure, monitor, report and control/mitigate sources of internal and external risk.

The specific risk management process for the Project was undertaken in accordance with Stanwell's Board approved Risk Management Policy and Framework and Enterprise Risk Management and Business Resilience Policy (*which adopts the principles of ISO:31000 (2018) and COSO ERM – Integrating with Strategy and Performance (2017)*).

7.2 Risk Management Plan

A project-specific RMP was developed for the project to enhance the analysis of risks associated with the Project and evaluate opportunities, and a series of risk workshops were conducted to identify the risks and opportunities associated with the Project.

7.2.1 Feasibility Study & Project delivery risks

Table 43: Feasibility Study & Project delivery risks

Risk Context	Risks/opportunities associated with the successful delivery of the Feasibility Study.
Responsible	Stanwell Project Director
Facilitated by	Stanwell Project Risk Lead
Artifacts	Project Risk Register
Review Frequency	Monthly review with project risk owners
On-going Monitoring	• Monthly risk reporting to Stanwell Steering Committee • Monthly risk reporting to Consortium Steering Committee

7.2.2 Technical risks

Table 44: Technical risks

Risk Context	Detailed capital cost, Health, Safety and Environment and process safety and regulatory risks/opportunities associated with: • Power Generation • Power Transmission and Distribution • HPF, Process Systems/Process Plant • Pipeline and Storage • HLF and Port Integration • Facility Design, Site and Geotechnical • Ancillary Services (WS,T&C, WM) • Supply Chain Eng/Process Optimisation • Process Safety and Technical Risk • Technical Economic Modelling • OEM Integration • Technical Programme Management • ECI/OEM Engagement • Regulatory requirements/ approvals
Responsible	Stanwell Technical Workstream Lead
Facilitated by	Technical Advisor(s)
Artifacts	Technical report

7.2.3 Commercial risks

Table 45: Commercial risks

Risk Context	Detailed market, funding and contracting strategy risks/opportunities associated with: • Supply Chain Modelling and Financial Structures • Offtake and Financing Integration • Tax and Accounting Considerations • Grant and Concessionary Debt • Financing • Offtake Strategy and Term Sheets • JV Consortium Structure and Agreements • Renewable Energy Strategy • Power Supply Agreements and Term Sheets • Port Agreements and Term Sheets • Land Due Diligence and Term Sheets • Water Supply Agreements • Other Infrastructure and Requirements
Responsible	Stanwell Commercial Workstream Lead
Facilitated by	Commercial Advisor(s)
Artifacts	Commercial report

7.2.4 Stakeholder/social risks

Table 46: Stakeholder/social risks

Risk Context	Detailed social impact, first nations and regulatory risks/opportunities associated with: • Stakeholder Analysis • Stakeholder Engagement • Strategy and Plan • Social Impact Assessment • Public Interest Assessment • Sustainability Assessment • Strategic Summary • Cultural Heritage, Native Title and Management Plan • Consortium/JV Setup and Engagement • State and Federal Approvals (Policy and Structuring) • Workforce Skills and Training Assessment
Responsible	Stanwell Strategic/Engagement Workstream Lead
Facilitated by	Strategic/Engagement Advisor(s)
Artifacts	• Social Impact Assessment • Regulatory Approvals Report

7.3 Summary of risks

The Project Risk Register is the primary risk register for the Project.

The risks were segmented by workstream, and include technical risks, commercial risks, and social and stakeholder risks. These risks have been assessed by the specific workstream teams and reviewed to ensure alignment between risk identification and treatment where risk classification overlap is present.

Below is a summary of the most significant residual risks, identified across the technical, commercial and stakeholder workstreams, which will require further consideration as the project moves into FEED.

More detailed technical, commercial, regulatory and stakeholder risk information can be found in the relevant reports/sections of the Feasibility Study report.

7.3.1 Technical risks

Table 47: Key technical risks

Phase	Project Element	Risk Description	Impact(s)	Mitigation
Phase 1	Energy	Risk that power infrastructure tenure does not have sufficient capacity to support Phase 1 requirements.	• Project execution delays.	• Alternate power infrastructure alignment options to be developed including possibility of re-routing the 66KV line over the HPF site
	Water	Risk that sufficient volumes of water (H2 production and cooling water and liquefaction cooling water) required for Phase 1 production and liquefaction volumes will be unable to be secured.	• Project execution delays.	• HPF design considerations include options for reducing production water consumption volumes. • Alternate water supply options to reduce reliance on locally available raw water (i.e. Potential for seawater cooling for HLF). • The proposed Fitzroy to Gladstone pipeline may address this if the pipeline proceeds.
		Risk associated with obtaining regulatory approval to allow HPF wastewater discharge resulting in project delays.	• Project execution delays. • Additional cost of utilising alternate wastewater methods.	• Option of beneficial re-use of wastewater using on-site irrigation for Phase 1 (may require restricting re-use to Aldoga site specifically).
		Risk that the wastewater pipeline infrastructure and related tenure not sufficiently researched/understood resulting in project execution delays.	• Project execution delays.	• Wastewater pipeline design to consider pump size and pipeline diameter. • Option to consider an extension of this pipeline out to Yarwun water treatment plant.
	Gas	Gas pipeline infrastructure and related approvals result in project execution delays.	• Project execution delays. • Phase 1 may incur additional cost associated with enabling Phase 2 capacity.	• Alternate gas infrastructure alignment options to be developed.. • Possibility to utilise a broader common user infrastructure approach as a part of Stanwell's involvement with the CQH2 alliance.

Phase	Project Element	Risk Description	Impact(s)	Mitigation
	Electrolysers	Risk that the project will be unable to secure electrolysers to meet Phase 1 project delivery timeframes.	• Project execution delays.	• Procurement of electrolysers from multiple OEMs for phase 1 (e.g. 2 x 50 units) • Option to secure long lead time items by securing OEM manufacturing slots with pre-payment.
		Risk that Phase 1 electrolyser pricing does not remain price competitive or show technical innovation before Phase 2.	• Uncompetitive cost of electrolysers	• Option to tender for electrolysers again, but the JV would have less knowledge & less relationship with new vendors.
	Regulatory	Risk that an unclear distribution of the three main project facilities (HPF, Pipeline, HLF) compliance responsibilities will result in possible non-compliance with elements of the relevant Acts and Regulations.	• Results in overlap / unaligned approval conditions at interface points. • Reduced regulator and community confidence and understanding of project impacts to the region.	• Allow for clear separation of approvals (and compliance obligations) for the different project facilities (and owners/operators) • Assess all project facilities as a single action rather than "piece-meal" and that any cumulative impacts have been appropriately considered to improve confidence with regulators and the community. • Separation of Phase 1 and Phase 2 approvals. • As practicable, approvals for different project components should be lodged (and assessed) in parallel. • Approval conditions should be reviewed and negotiated considering other project components.
Phase 2	Energy	Risk that sufficient volumes of renewable energy required for Phase 2 'green' H2 production volumes will be unable to be secured due to a lack of regional availability.	• Project execution delays • Reduced project viability • Loss of funding • Inability to attract investors • Inability to finance project	• Stanwell is leading a coordinated power infrastructure planning approach for the Central QREZ with Qld Government and supported by CQ-H_2 Consortium. • Stanwell will leverage its energy expertise and counterparty strength to develop partnerships with renewable energy developers to secure the energy requirements for Phase 2.
		Risk that the energy requirements required for Phase 2 production volumes will be unable to be secured due to a lack of suitable power transmission infrastructure.	• Project execution delays. • Inability to proceed to Phase 2.	• Option to consider utilising private/ non-network transmission infrastructure. • Stanwell is leading a coordinated power infrastructure planning approach with Qld Government which is supported by CQ-H_2 Consortium.

Phase	Project Element	Risk Description	Impact(s)	Mitigation
	Water	Risk that sufficient volumes of water (H2 production, cooling water and liquefaction cooling water) required for Phase 2 production and liquefaction volumes will be unable to be secured.	• Project execution delays. • Inability to proceed to Phase 2.	• Option for water production using desalination • Alternate water supply options to reduce reliance on locally available raw water (i.e. Potential for seawater cooling for HLF).
	Electrolysers	Risk that the project will be unable to secure electrolysers to meet Phase 2 project delivery timeframes.	• Project execution delays.	• Possible option to enter into a rolling manufacturing agreement with OEM(s) to secure sufficient quantities in the required timeframe for phase 2.
		Risk that the electrolyser RFQ (Phase 2) does not have price / energy efficiency characteristics that support project financial objectives.	• Non-commercial HPF • Reduced project viability	• FEED study to include further technical analysis. • Procurement strategy to include desired technical characteristics.
O&M	**Safety**	Risk of a significant safety incident due to confusion / inexperience with operation and maintenance of HPF resulting in a catastrophic plant failure.	• Significant health & safety incident. • Loss of production.	• HAZID and process safety outcomes have been identified for incorporation into design considerations.

7.3.2 Commercial risks

Table 48: Key commercial risks

Phase	Project Element	Risk Description	Impact(s)	Mitigation
Phase 1	**LCOH**	Risk that the lowest possible cost of hydrogen cannot be achieved.	• Non-commercial HPF • Reduced project viability • Loss of funding • Inability to attract investors • Inability to finance project	• Option to include novel T&Cs in off take contract (e.g. price shaping, ceiling and floor prices to share rise and fall over long term). • Option to explore alternate domestic or international offtake opportunities to offset the inability to secure of long term offshore off taker.
		Risk of cost inflation associated with project procurement, construction, technology & infrastructure.	• Non-commercial HPF • Reduced project viability • Loss of funding • Inability to attract investors • Inability to finance project	• Detailed project implementation plan which identifies works and materials that are more price volatile • Explore options for multi-stage tendering to de-risk inflation
Phase 1 & 2	**Offtake agreement**	Risk that funding may not be viable to financiers without an offtake agreement	• Inability to attract investors • Loss of funding	• Determine structure of offtake agreements and advance contracts before sourcing funding.
Phase 1 & 2	**Project structure**	Risk of deterring investment by complicating requirement for funding across the CQ-H2 supply chain.	• Inability to attract investors • Loss of funding	• Maintain engagement with prospective lenders throughout project planning and feasibility stages to gain an understanding of lenders' appetites for different structures.
Phase 1 & 2	**Construction**	Risk of project delays and/or project running over budget due to incorrect planning or other unforeseen circumstances.	• Inability to attract investors • Loss of funding • Cost overruns	• Selection of a suitable EPC contractor as well as conducting Independent Engineering Reports will alleviate concern from lenders.

Phase	Project Element	Risk Description	Impact(s)	Mitigation
Phase 1 & 2	**NPV/Tax**	Risk that the thin capitalisation regime will apply to the Project due to the investment non-resident entities.	• Interest deduction proportionately denied to the extent that the Project's debt exceeds the maximum allowable debt under the thin capitalisation regime.	• Where non-resident investment in the Project exceeds the relevant threshold, ensure debt levels are under the maximum allowable debt under the thin capitalisation regime.
Phase 1 & 2	**NPV/Tax**	Risk that the grant funding received for the Project is taxable upfront.	• Timing mismatch between the assessability of the grant and deductions for project expenditure.	• The preferred project structure should allow for an optimized income tax treatment of any grant funding. A Private Binding Ruling would be required to achieve certainty.
Phase 1 & 2	**NPV/Tax**	Risk that the continuity of ownership test is failed in respect of tax losses generated in Phase 1 where additional external parties invest in Phase 2 of the Project.	• The business continuity test would instead be required to be satisfied to recoup any Phase 1 losses.	• Contemporaneously document business continuity test requirements on an annual basis.

7.3.3 Stakeholder risks

Table 49: Key stakeholder risks

Phase	Project Element	Risk Description	Impact(s)	Mitigation
Phase 1	**Water**	Perception from local community and industry that the project will have an adverse impact on local water supply.	• Adverse impact to other local industries (irrigators etc) • Ecological impacts • Social license to operate concerns.	• HPF design considerations include options for reducing production water consumption volumes. • Alternate water supply options to reduce reliance on locally available raw water (i.e. Potential for seawater cooling for HLF). • On-going community education and engagement programs • Involvement in State and Federal development groups to develop consistent community messaging around water and other social issues.

Phase	Project Element	Risk Description	Impact(s)	Mitigation
	First Nations	Risk that poor engagement with First Nations groups will result in project execution delays.	• Project execution delays. • Reduced community support for the project.	• CQ-H_2 Project First Nations Engagement Framework has been developed and includes focus on "Creating Jobs and Business", "Making and Honouring Commitments", "Being Culturally Responsive", and "Supporting First Nations Aspirations".
	Community Safety	Perception from the local community and industry that the project will introduce a health & safety risk to the community (e.g. storage and transport of hazardous materials).	• Project execution delays. • Reduced community support for the project.	• Ongoing engagement with the local community and other relevant stakeholders (including emergency services) to provide clear, factual and accurate information regarding the safety aspects of the project. • The technical workstream has undertaken safety, hazard and environmental assessments. The outcomes of these will be incorporated into the safe design of production facilities.

7.3.3.1 Climate and environmental risks

Table 50: Key climate and environmental risks

Phase	Project Element	Risk Description	Impact(s)	Mitigation
O&M	**Water**	Risk that water has ongoing reliability issues due to environmental and weather factors (drought) impacting the HPF and HLF.	• Reduced capacity to produce H2 at the HPF at the required volumes to meet offtake requirements.	• HPF design considerations include options for reducing production water consumption volumes. • Alternate water supply options to reduce reliance on locally available raw water (i.e. Potential for seawater cooling for HLF). • The proposed Fitzroy to Gladstone pipeline may address this if the pipeline proceeds.

7.3.4 COVID-19 risks

Table 51: Key COVID-19 risks

Phase	Project Element	Risk Description	Impact(s)	Mitigation
All	**Project Delivery**	Project delivery suffers significant delays due to COVID-19 control measures.	• Project execution delays.	• COVID-19 business continuity plans are in place and effective.
	Commercial Viability	The economic impacts of COVID-19 negatively affect proposed off-takers/partners resulting in the project commercial model being less viable.	• Reduced project viability • Loss of funding • Inability to attract investors • Inability to finance project	• Ongoing engagement with domestic and international partners.
Phase 1 & 2	**Procurement**	The economic impacts of COVID-19 negatively affect OEMs resulting in increased delivery lead times.	• Project execution delays. • Higher procurement and transport costs.	• Rigorous RFQ process • Early identification of long lead time items.

8 Regulatory approvals

The *Regulatory Approvals* section of this Feasibility Study report provides an outline of the following:

- Regulatory approvals overview and approach;
- Technical approvals, including key approval processes/pathways, preliminary environmental assessment, workplace health and safety (major hazard facility), and Phase 2 consideration;
- Stakeholder approvals, including native title (and ILUA), cultural heritage and tenure; and
- Continuing engagement with regulatory approval bodies.

8.1 Regulatory Approvals Overview

Regulatory Approvals approach

Within the Australian industry environment, regulatory approvals are key determinants of the delivery schedule for infrastructure projects. This is particularly relevant to new industries such as renewable (green) hydrogen, where regulators may be required to interpret and apply legislation (such as the *Petroleum and Gas (Production and Safety) Act 2004* (Qld) (P&G Act)) within a novel context.

At present, hydrogen pipelines are not covered within the P&G Act. In lieu of there being no existing legislative framework governing hydrogen pipelines, the Project has needed to adopt an alternative approach to land acquisition and securing of tenure that will ensure Project development milestones are met.

Early and sustained engagement with State and Federal regulatory approval bodies and government agencies, including pre-lodgement meetings and project briefing sessions, have been undertaken throughout the Feasibility study. The purpose of these engagement activities was to increase the level of understanding of the Project within those agencies and pre-empt potential impediments to gaining approvals (associated with internal knowledge, understanding and expertise relating to the hydrogen industry). This is of particular importance, given that the development of a hydrogen industry is in it's infancy in Australia and with no previous experiences or precedent to refer to for projects of a similar size and scale.

The Feasibility Study sought to identify the Queensland and Commonwealth regulatory planning and environmental approvals, and any non-regulatory agreements required for the development of the Project. A detailed RAP was developed, which details:

- Approval strategy considerations;
- A preferred approval pathway;
- Required regulatory approvals and associated assessment processes and timeframes;
- Approval risks and opportunities;
- Potential constraints for the Project.

A regulatory approvals register has been prepared and is included as part of the RAP. The register outlines various approvals anticipated to be required for the Project and details the legislation, relevant approval/consent/agreement, Project component(s) with the potential to trigger the requirement for approval/consent/agreement, the administering authority, and an indicative assessment timeframe (from lodgement).

It should be noted that not all Project approvals are within the remit of the Consortium. While the Consortium has responsibility to apply for and obtain most approvals listed in the approvals register, several approvals are the responsibility of 3rd parties. Some of these elements have not been finalized between the Consortium and those external parties and the Consortium will advance those discussions in line with the current planning and approvals schedule.

The schedule for regulatory approvals is based on the current definition of the Project, the current ownership structure proposed within the Consortium and understanding of the associated approvals required. The schedule is contained in the RAP. The approach for the Regulatory Approvals schedule involves integrating key milestones into the overall Project schedule.

Key dependencies on technical deliverables to support applications have been identified and scheduled to minimise potential delays in the overall approvals process. Until the preparation of approval applications is undertaken, the schedule will continue to be refined based on changes in project definition and feedback from early regulator/stakeholder engagement which has occurred throughout the Feasibility Study.

Key decisions relating to the approach to regulatory approvals for the Project were initially developed and have been validated via early engagement with the relevant state and federal government referral agencies. High level considerations are as follows:

- ***Separating approvals by Project Phase:*** the decision was made to stage & seek separate approvals for Phase 1 and 2, with this primarily driven by the delivery schedule for Phase 1. It was determined that the level of Project definition and technical information required for approval applications related to Phase 2 would unlikely to be available within the Phase 1 execution schedule timeframe.
- ***Coordinated Project declaration not selected for advancement:*** the decision was made, in consultation with state government agencies, that the Project would not seek a Coordinated Project (CP) declaration (administered under the *State Development and Public Works Organisation Act 1971* (SDWPO Act)) for Phase 1. Key considerations not to proceed with as a Coordinated Project include:
    - As the Project components are within the Gladstone State Development Area which is aimed to provide a more streamlined overall approvals process, a CP declaration is likely to provide minimal additional benefits;
    - The likelihood the overall regulatory approvals process would add significant time to the overall schedule and limit the Project’s ability to reach the targeted FID in 2023; and

The regulatory approvals have been segmented by Project component, with the Project intending to lodge separate applications for the three distinct components (HPF, hydrogen transport pipeline, and HLF/Wharf), aligning with the anticipated ownership structure of the facilities. The regulatory approvals strategy has been developed for Phase 1, with the Phase 2 strategy planned for development in the future.

The anticipated applications are:

- 3 separate “related project” referrals under the *Environmental Protection and Biodiversity Conservation Act 1999* (EPBC Act) for the HPF, hydrogen transport pipeline and HLF (with subsequent separate assessment processes in the event of a “controlled action” decision(s))
- 2 separate GSDA approval applications (HPF, hydrogen transport pipeline & wastewater pipeline)
- 2 separate *Planning Act 2016* (Planning Act) / Gladstone Port Land Use Plan (LUP) development approval applications (hydrogen transport pipeline & wastewater pipeline, HLF)
- 2 separate environmental authority (EA) applications:
    - HPF prescribed environmentally relevant activities (ERAs)
    - HLF prescribed ERAs
- other permits: individual applications pertaining to each component of the Project

Based on early regulator engagement and feedback, the lodgement of the relevant Federal and State approval applications will be provided as a bundle.

It is planned that a Phase 2 regulatory approvals strategy will be developed, which will identify Phase 2 approval requirements, including new approvals required and/or Phase 1 approvals amendments.

8.2 Technical Approval

Technical approvals for the Project are focused on planning and environmental considerations across both Commonwealth and State jurisdictions. These encompass Matter of National Environmental Significance (MNES), Matters of State Environmental Significance (MSES), Development Approvals (DAs) and other various approvals/permits required by legislation.

Key approval processes/pathways for the Project are summarised in the table below.

Table 52: Key approval processes/pathways

Legislation/Approval	Impacted Project Component
Commonwealth Approvals	
EPBC Act	• Required if potential to impact MNES for the HPF, Pipeline and HLF.
State Approvals	
GSDA approval(s) administered by the Office of the Coordinator General (OCG)[48]	• HPF • Extent of hydrogen transport pipeline within GSDA • Extent of wastewater pipeline within GSDA • For construction and operation of a switchyard and stepdown transformer adjacent to the existing Larcom Creek substation, proposed to facilitate grid power supply for the project
Operational work approval under GRC planning scheme for project infrastructure located within the GSDA	• HPF • Section of hydrogen transport pipeline corridor within GSDA
Development approval(s) under the Planning Act and Port LUP for facilities within Strategic Port Land (SPL)	• HLF • Section of hydrogen transport pipeline within SPL • Section of wastewater pipeline located within SPL • Construction & operation of wharf infrastructure • Dredging of berth pockets, approach and swing basin
Environmental Authorities under the *Environmental Protection Act 1994* (EP Act)	• HPF • HLF
Stand-alone permits/approvals required under specific legislation (detailed in RAP)	• Required for HPF, pipeline and HLF including MSES approvals
Notification and licensing of project facilities that qualify as Major Hazard Facilities (MHFs) under the *Work Health and Safety Regulation 2011* (WHS Regulation)	• Facilities that qualify as MHFs

[48] This approval process includes assessments typically triggered for approvals required under the *Planning Act 2016 (QLD)*

8.2.1 Preliminary Environmental Assessment

As part of the environmental assessment undertaken during the Feasibility Study, a preliminary terrestrial ecology desktop assessment was undertaken by specialist ecologists, focused on determining the known/likely presence of ecological values over the entire project footprint.

Through the desktop assessment, ecological values were identified, with a particular emphasis on flora, fauna and ecological communities protected under Commonwealth and State legislation (MNES and MSES respectively). A review of publicly available mapping, databases and previous ecological studies undertaken in the local area formed part of the assessment.

Detail relating to the assessment of the HPF (Aldoga site), hydrogen transport pipeline and HLF (Fisherman's Landing site) is contained in Section 5 of the RAP.

A high-level assessment of the potential impacts is provided in Table 53. Further ecological impact assessment work is required for determination of the likelihood the impacts listed will eventuate and the significance of these. Detailed studies are ongoing.

Table 53: MNES and MSES potential impacts

Level	Potential impacts
MNES	• Coastal Saltmarsh and Coastal Swamp Oak TECs (both pipeline alignment options) • Semi-Evergreen Vine Thicket (Landing Road pipeline alignment option) • Threatened flora and fauna species
MSES	• Endangered and Of Concern remnant vegetation (pipeline) • Protected wildlife habitat (HPF, pipeline) • Connectivity areas (pipeline) • Marine plants (pipeline – near causeway to Fisherman's Landing)

8.2.2 Workplace Health and Safety (Major Hazard Facility)

Major Hazard Facilities (MHFs) are facilities that store above threshold quantities of schedule 15 chemicals (*Work Health and Safety Regulation 2011* (WHS Regulation)), or those which are deemed a MHF after an inquiry process.

MHFs include oil refineries, chemical plants and large fuel & chemical storage sites used for storage, handling or processing of large quantities of hazardous material. In Queensland, MHFs also include facilities that store above threshold quantities of explosives and undertake some processing activity.

The WHS Regulation requires licensing of all MHFs, notification to and an inquiry process by the regulator for facilities with >10% of Schedule 15 chemicals (to determine MHF status), and an MHF operator to identify security arrangements for preventing unauthorised access as part of their safety case regime (and for the operator to consult with the local council and local community – generally about operations, and in the event of a major incident – and the Queensland Fire and Rescue Service regarding preparation & review of emergency plans).

The HPF is likely to constitute a "Material Particular" requiring notification. Early engagement with Workplace Health and Safety Queensland (the regulator) is set to commence in the period leading up to the lodgement of the relevant approvals.

8.2.3 Phase 2 consideration

It is planned that a Phase 2 regulatory approvals strategy will be developed, which will identify Phase 2 approval requirements, including new approvals and/or Phase 1 approval amendments required.

A review of Phase 1 approval activities will be undertaken, with the aim to (where practicable), minimise constraints and maximise potential benefits for the Phase 2 development. More specifically, impact assessment studies will consider Phase 2 impacts where possible, approval applications for Phase 1 will present the larger development (including expected impacts if possible), and Phase 1 approval conditions will be reviewed and negotiated to minimise constraints on Phase 2 development.

Environmental impacts of Phase 2 associated with the HLF sea water exchange and increased volumes of offshore wastewater discharge from the HPF/HLF are likely to receive scrutiny from regulators, given the proposed location for discharge. Australian precedent exists for securing regulatory approvals for desalination and regasification plants that impact salinity and temperature of receiving environments however these are for projects outside of Queensland. Locally in Gladstone some examples exist. The Gladstone Power Station discharges heated water into the Calliope River, which is believed to cause an increase in water temperature of between 2 °C and 5 °C in the waters immediately adjacent to the outlet. Also, Rio Tinto Yarwun discharges wastewater from Fisherman's Landing (close to the proposed location of the HLF), which includes boiler blowdown along with other wastewater, but temperature is not specifically limited on their EA.

For the CQ-H_2 Project, it is likely that investigation and justification of these impacts would require significant effort and may have impact on the strategy for regulatory approvals.

8.3 Native Title (including ILUA), Cultural Heritage and Tenure

Native Title

Native Title in Australia is primarily governed by the *Native Title Act 1983* (Cth) (Native Title Act). Where Native Title has been determined to exist or may exist, the Native Title Act sets out processes to take account of Native Title when parties wish to undertake activities or take an interest in land ("future acts"). Grant of new land tenure for pipeline establishment over land where Native Title exists is likely to be a future act.

The entire Project area is within the outer boundary of the former Port Curtis Coral Coast (PCCC) Native Title claim with Native Title to be held by First Nations Bailai, Gurang, Gooreng Gooreng, Taribelang Bunda People Aboriginal Corporation Registered Native Title Body Corporate (RNTBC) who are generally referred to as the PCCC Native Title group.

The processes and timeframes for negotiating an ILUA will generally be driven by the requirements of the Native Title party (in this case the RNTBC representing the Native Title holders) and its advisors. Once the ILUA has been negotiated with the native title holders (via the RNTBC), one party lodges the ILUA with the Native Title Registrar for registration on the Register of Indigenous Land Use Agreements. The registration process for a body corporate agreement includes a 1-month notification period.

Cultural Heritage

The *Aboriginal Cultural Heritage Act 2003* (Qld) (ACHA) governs the protection & management of Aboriginal cultural heritage in Queensland.

A range of pathways are provided by the ACHA for Project proponents to take reasonable steps to protect cultural heritage.

Further details on the cultural heritage considerations and scheduling requirements are contained in the RAP.

8.4 Continuing engagement with regulatory approval bodies

To maintain the current schedule for all regulatory approvals for Phase 1 of the Project, engagement with regulatory approval bodies needs to, and will be undertaken in the period between completion of the Feasibility Study and commencement of the FEED Study.

9 Social and stakeholder engagement

The CQ-H_2 Project recognised that engagement with stakeholders and social impact management are key to the success of the Project and this workstream formed a key element in the Project's planning and Feasibility Study development. Members of the Project team and the Stakeholder advisory team engaged actively with stakeholder groups in the Gladstone area.

At the commencement of the Feasibility Study, documents were prepared to guide stakeholder engagement and social performance planning and implementation for the CQ-H_2 Project. These documents are included as supporting documents to the Feasibility Study and are listed below.

- Social Baseline;
- Stakeholder Mapping and Issues Analysis;
- Stakeholder Engagement Framework, inclusive of First Nations Engagement Framework and Community Education Framework;
- Social Impact Assessment;
- Public Interest Assessment;
- Sustainability Assessment.

Other supporting documents are Stakeholder Engagement Approach Per Stakeholder Group and Cultural Heritage Database and Register results.

9.1 Social Baseline

The following section examines the location and population, traditional ownership, regional history, industry profile and social and community characteristics of the Gladstone region. A comprehensive social baseline for the Gladstone region is provided in the CQ-H_2 Project Social Baseline report.

Location and population

Gladstone is located approximately 550km north of Brisbane (by road), and 100km south-east of Rockhampton. The Gladstone Local Government Area (LGA) covers 10,500 square kilometres and has a population of 63,000.

Traditional owners

The Traditional Owners of the Gladstone region are Bailai, Gooreng Gooreng, Gurang and Taribelang Bunda people and are collectively represented by the PCCC Trust. Land within the Gladstone region falls under the PCCC determination.

The PCCC represents these First Nations groups as a RNTBC. The PCCC RNTBC is responsible for managing all Native Title matters across the Bundaberg, Gladstone and part of the North Burnett regions and is the Registered Cultural Heritage Body. The RNTBC is responsible for traditional management of Country and waterways under the PCCC Traditional Use of Marine Resources Agreement (TUMRA) made with the Great Barrier Reef Marine Park Authority (GBRMPA) and the Queensland Government.

For the Gladstone region, the PCCC manages the ILUA benefits and delivers programs for the PCCC Traditional Owners. An ILUA is a voluntary agreement between Native Title parties and other people/bodies, that addresses the use and management of areas of land and/or waters. The PCCC has ILUAs in place with GPC, GAWB, and the various LNG proponents in the area.

Industry profile

Gladstone is known as an established industry city. The industry profile of Gladstone has diversified over the past decades, to include aluminium smelting and refining facilities, as well as LNG processing, power generation, cement and lime manufacturing, mining and industrial chemicals, and coal export.

The majority of Gladstone's industry is located adjacent to the coast and the Port of Gladstone, situated north of the city of Gladstone within the Gladstone State Development Area (GSDA).

Major companies operating in Gladstone include:

- GPC;
- Cement Australia;
- Orica Australia;
- NRG Gladstone;
- Queensland Energy Resources;
- Southern Oil;
- Santos GLNG;
- Shell QGC (QCLNG);
- Australia Pacific LNG (APLNG);
- Wiggin Island Coal Export Terminal (WICET).

In addition to existing industry operations, there are a number of renewable energy projects proposed for the Gladstone region, including the Global Green Energy Manufacturing Centre (GEM) proposed by Fortescue Future Industries (FFI) in partnership with the Queensland Government. Both the Queensland Government and Australian Government have declared Gladstone a "hydrogen hub" with several hydrogen projects proposed for the area (some are yet to be publicly announced). The Gladstone region also falls within the Central QREZ.

The manufacturing industry sector is the largest contributor to economic output in the region, with \$5.7 billion (37.26 per cent of total output) and the largest employer, with over 4,000 jobs (representing almost 15per cent of total employment within the region).

Despite the relative wealth, the Gladstone region has experienced major changes over the past couple of decades, primarily due to 'boom and bust' cycles associated with the resources and energy industry. The most recent 'boom' occurred between 2011-2015, during the simultaneous construction of three LNG plants on Curtis Island ('APLNG', 'GLNG' and 'QCLNG'), Rio Tinto's Yarwun Stage 2 expansion, and the Wiggins Island Coal Export Terminal construction. The construction of these facilities led to a rapid increase in the Gladstone population, which in turn increased the costs of housing, goods and services. The completion of construction, however, had a significant impact on the economic sustainability of the city, and large social impact was experienced. The market value of housing dropped significantly, and accommodation vacancy rates increased due to workers leaving town.

Tough economic conditions also necessitated industry transformation, resulting in redundancies. In 2017, Rio Tinto's local operations (QAL, Boyne Smelters Limited (BSL), and Yarwun), NRG Energy Power Station and Orica all undertook workforce reductions (some significantly).

While the Gladstone economy has slowly started to recover, there has been growing socio-economic disadvantage over a five-year period, with an increasing demand for welfare and support services and a decline in the wellbeing of children residing in the region. The increased demand for local welfare and support services has been impacted by a drop in house and rental prices prompting lower socio-economic groups to move into the Gladstone region during 2016-2020.

Within the past two years, the increased spend from Rio Tinto's Gladstone Operations and the proposed hydrogen developments for the local area have created optimism within the community that the Gladstone region is on another 'up cycle'.

The Gladstone community is anticipating regional growth, economic development, and enhanced liveability. The community is, however, concerned about potential cumulative social impacts of expanding industry, particularly in relation to the proposed hydrogen developments, and the proposed Central QREZ and its associated renewable energy projects.

Key community trends and characteristics

Key demographic statistics for the Gladstone region and Queensland are summarised in Table 54.

Table 54: Key statistics - Gladstone LGA compared to Queensland[49]

Demographic aspect	Gladstone LGA	Queensland
Total population, 2016	61,640	4,703,193
Average annual growth rate, 2016 – 2021 (%)	1	0.9
Median age, 2016	35	37
Indigenous population, 2016 (%)	4	4
Same address 5 years previous, 2016 (%)	46	44
Completed Year 12 education, 2016 (%)	32.3	52.2
Unemployment, Sept 2021 (%)	6.3	4.9
Main industry of employment, 2016 (%)	'manufacturing' (14.4)	'healthcare and social assistance' (13)
Media weekly income (household), 2016	$1,586	$1,402

Source: ABS 2016, QSO, 2022

In 2016, the median weekly household income for residents in the Gladstone local government area (LGA) was $1,586 which was higher than that of Queensland overall ($1,402) and neighbouring Rockhampton LGA ($1,255) and is likely linked to the 'boom' of the resources and energy sector between 2011-2015[50]. It is noted, however, the median household income in 2016 was $138 less than the 2011 Census data, indicating a salary decline following the boom.

Other key community characteristics are summarised below.

Table 55: Key community characteristics

Metric	Information
Household composition	• 74% of households in the Gladstone LGA were families, with an average household size of 2.6 people (and 3.1 for Aboriginal and Torres Strait Islander households) • Couples without children made up 45.5% of family households
Labour force participation rate	• 63.8% in 2016, of which over half worked full-time
Employment by gender	• Male employment was higher than females across all age groups
Main occupations	• Males dominated technician and trade worker occupations (only 12% of females reported being employed in this field) and labourer occupations (63%)

[49] These figures are from 2016 and reflect the LNG boom. Data from the 2021 census is expected to be available in June 2022.

[50] Australian Bureau of Statistics 2016 Census – 2021 figures not available at time of finalising this report

Metric	Information
	• More females (58%) than males were employed as professionals, cleaners, laundry workers, and food preparation assistants
ATSI employment	• Over 40% of Aboriginal and Torres Strait Islander people in Gladstone LGA were in full-time employment compared with Queensland (20%)
Unemployment rate	• The rate of unemployment in Gladstone LGA has ranged from 6-8.2% over the last five years and has generally been higher than the unemployment rate across Queensland • In the September 2021 quarter, the unemployment rate for Gladstone LGA was recorded as 6.3% compared with Queensland's rate of 4.9% for the same quarter • This is reflective of an economy in transition post the LNG project construction 'boom'
Education level	• 32% of residents aged 15 and over in Gladstone had completed a year 12 education, compared with 52% across the State • The lower proportion of those completing this level or schooling is likely linked to the types of employment available in the area; a good proportion of which requires only year 10 completion and trade qualifications
Youth migration	• There is a pattern of 15–24-year-olds migrating away from Gladstone to larger urban centres to seek further education and/or employment opportunities
Educational institutions	• Local tertiary and vocational education training institutions include the Central Queensland University (which incorporates a selection of TAFE programs) and the EQIP Technical College Gladstone • Stakeholders, however, perceive that there is a limited selection of courses available at Central Queensland University and that the courses are overly industry-focused and not sufficiently diversified
Childcare centres	• Gladstone reportedly has an insufficient number of childcare centres to meet demand, and this may be impacting female participation in the workforce
Health and welfare	• Health infrastructure and service provision is generally limited and under-resourced, particularly in regard to mental health services • Community health and welfare services in Gladstone LGA, including for seniors, youth, and the Indigenous population, are provided by a range of public and private organisations, including the Gladstone Hospital

9.2 Stakeholder Mapping and Issues Analysis

9.2.1 Key project stakeholders

Stakeholders include persons/groups likely to be interested in the Project. A stakeholder analysis was completed to identify those who would likely have a high degree of interest in the CQ-H_2 Project, and who could be directly or indirectly affected (positively or negatively) by the Project.

Key external stakeholder groupings for the CQ-H_2 Project are outlined in Figure 37. A comprehensive external stakeholder list is provided in the CQ-H_2 Project Stakeholder Engagement Framework.

Figure 37: CQ-H_2 key identified stakeholders

Australian, Queensland, Local Government and associated agencies	Australian and Queensland Ministers and Members of Parliament	Japanese Government	Traditional Owners and First Nations groups in the Gladstone areas
Gladstone regional community	Gladstone industry	Gladstone education and job connection providers	Gladstone community service providers
Gladstone community groups	Gladstone social investment groups	Gladstone and Central Queensland regional development groups	Hydrogen and renewable energy industry representative groups
Local fishing and boating groups	Local agricultural representative groups	Local natural resource management and environmental groups	Local environmental monitoring groups
Project utility providers	Industry suppliers	Unions	Australian regulators and market bodies
	Japanese hydrogen industry representative groups	Local and international media	

9.2.2 Stakeholder issues analysis

A comprehensive stakeholder issues analysis was completed for the CQ-H_2 Project, with the analysis identifying key areas of current community interest and considerations with respect to local industry. These include:

- Sustainable employment, training and supply opportunities
- Industry benefit sharing strategies including social investment / sustainable development
- The management of potential project and cumulative environmental impacts – both terrestrial and marine
- Growth of the local hydrogen and renewable energy industry, coordination of projects and required enabling infrastructure and services
- Potential project and cumulative social impacts, including to affordable housing and accommodation regional infrastructure (such as water supply, roads, recreational areas) and amenity
- Hydrogen development being a complementary land-use to, and coexisting with, existing regional industries
- Industry engagement with the regional community, Traditional Owners and key stakeholders
- Safety management of industry
- Competition for resources (such as land, workers, contractors, water) due to new industry projects being developed in the area at the same time.

Project stakeholder engagement completed in November and December 2021 confirmed the above listed stakeholder interests.

9.3 Stakeholder Engagement

A Stakeholder Engagement Framework and a First Nations Engagement Framework were prepared in line with leading practice to support the Project through feasibility and FEED activities. A Stakeholder Engagement Approach Per Stakeholder and Community Education Framework are also included as documents supporting this report.

Aims of the external engagement approach were as follows:

- Strategically implement engagement initiatives in a manner which proactively responds to stakeholders' interests and issues, including providing opportunities for key stakeholders to input to the Project
- Build and maintain positive and collaborative relationships with stakeholders that support the achievement of Project objectives and its social licence to operate
- Honour the Project Consortium's values and principles around timely, open, inclusive and meaningful engagement
- Achieve alignment with regulatory and industry good practice guidelines
- Facilitate the successful delivery of the Project.

Engagement approaches

A variety of consultation approaches and communication materials continue to be used to engage key external Project stakeholders. These include, but are not limited to:

Figure 38: Consultation approaches and communication materials

Face-to-face / video conference briefings and meetings	Presentations to stakeholder groups	Focus groups with stakeholder groups
Keynote speeches, discussion panels and displays at industry events	Participation in community activities and meetings	Targeted phone calls and correspondence
Project email address, free call contact number, and QR code for stakeholder contact registration	Site tours	Distribution of CQ-H_2 project information sheets
Use of key messages	Media releases and social media	Hosting of dedicated CQ-H_2 project webpage on the Stanwell website
	Publication of educational videos and podcasts	

Consultation approaches during Feasibility Study

The key focus of external stakeholder engagement was on seeking important information inputs to the Study, including to inform technical considerations, the Social Impact Assessment, Public Interest Assessment, environmental studies and regulatory approvals.

The CQ-H_2 Project has undertaken a targeted external stakeholder engagement program during Feasibility.

Focus groups and interviews

External engagement activities via focus group discussions and face-to-face interviews were undertaken with selected stakeholders from 29 November – 2 December 2021, to inform the Project's Social Impact Assessment and Project planning. Thirty external stakeholders were engaged in focus groups and interviews at this time.

The engagement program sought to consult selected stakeholders across five key focus areas, including:

Figure 39: Key stakeholder engagement focus areas

Business and business development	Education and training	Health and emergency services	Natural resource management	Community and social wellbeing

The engagement activity objectives were to understand the current and historical socioeconomic environment of the Gladstone region, examine potentially significant project impacts and opportunities, and seek feedback on proposed mitigation and management measures. Engagement sought to understand:

- Availability, capacity and future development plans of local social services and facilities, including current and foreseeable constraints
- Scope and scale of community and wellbeing issues in the region
- Industry development constraints and opportunities
- Local supply chain experiences, barriers and opportunities
- The needs and aspirations of the community, and key environmental issues of interest and concern
- Key issues of interest and concern to Traditional Owners and First Nations people in the Gladstone region
- Potential impacts of industry and workforce on services and the local community.

Consultation outcomes

The perceptions, values and issues raised by stakeholders and the local community during engagement activities undertaken for the Project to date are summarised in the document CQ-H2_Stakeholder Issues analysis.

Specific values and issues raised by PCCC Trust, representatives of the Traditional Owners in the Project area, during engagement activities undertaken for the Project are summarised in CQ-H2_Stakeholder Issues analysis.

9.4 Social Impact Assessment

A Social Impact Assessment was completed for the Project. Key potential impacts associated with the Project include:

- Exacerbating competition for local labour
- Increased demand for housing and accommodation, affecting affordability and availability
- Contributing to an increased cost of living in Gladstone due a potential hydrogen industry ‘boom’
- Increased risk (real or perceived) of impacts on tourism and on recreational fishing
- Loss of or destruction of cultural heritage
- Loss of access to areas of Indigenous cultural significance (including marine areas)
- Traditional Owners and First Nations community perceive that they have missed out on Project and hydrogen industry opportunities
- Increased risk of spread of communicable diseases amongst local community and reduced community safety (real/perceived) as a result of the Project's non-resident workforce and opportunistic migrants moving into the local area

- Increased health and safety risks due to the Project, such as storage and transport of hazardous materials
- Increase in amenity disturbance due to increased noise, reduced air quality during construction of the Project
- Increased demand on existing infrastructure (roads, hospitals etc) and service provision (health, childcare, community services) due to Project-related and opportunistic population influx
- Reduced or constrained industry and community access to water resulting from competing industry demands for water
- Changes in income due to loss of employment associated with the transition from Project construction to operations.

The Project's potential opportunities include:

- Direct and indirect local employment and training
- Direct and indirect local supply
- Social investment
- Further stimulating and diversifying the local economy
- Improvements in health and wellbeing (including mental health) due to changes in economic determinants and other lifestyle choices as a result of the Project and hydrogen industry economic benefits
- Supporting the transition to renewable energy.

The Project will develop and implement the following frameworks, plans and strategies detailing social impact management measures to address the issues and opportunities raised by Traditional Owners and other key stakeholders:

- Continue to implement the Project Stakeholder Engagement Framework, inclusive of Community Education Program and grievance mechanism
- Prepare and implement a Project Social Impact Management Plan
- Prepare and implement a Project Local and First Nations Participation Plan
- Prepare and implement a Project Social Investment Strategy
- Complete cultural heritage studies in collaboration with the Traditional Owners, and develop and implement a Cultural Heritage Management Plan
- Prepare and implement a voluntary agreement with the Port Curtis Coral Coast Trust
- Major Project Contractors should develop and implement community health, wellbeing and safety plan/s.

The frameworks, plans and strategies will be developed and implemented during the Project's FEED stage.

9.5 Public Interest Assessment

A Public Interest Assessment was completed for the Project and there are no foreseen public interest issues that would prevent the CQ-H_2 Project from proceeding.

The Project presents opportunities for locals through employment and training, local content, and social investment. The Project also has some potential impacts including increased demand for local housing, social infrastructure services and labour, however these can be managed.

Engagement outcomes suggest that the community endorses the Project and developing hydrogen industry, as long as potential cumulative social impacts will be appropriately managed.

9.6 Sustainability Assessment

A sustainability assessment was completed for the Project. The assessment began with a workshop aimed at understanding the strategic context for sustainability on CQ-H_2, including key strategic drivers, enablers, constraints and aspirations. This interactive framing and alignment workshop was completed on 4 November 2021.

Informed by the outcomes of the framing and alignment workshop, a Materiality Assessment was then completed to clearly identify all environmental and social risks and opportunities, and expected economic implications, and to direct the development of strategy. The Materiality Assessment aligns with Level 2 of the LEA-1 (Integrating Sustainability) credit of the ISCA ISv2.0 Technical Manual (Planning).

Materiality Assessment

A Materiality Assessment is the process of identifying, refining and assessing numerous potential environmental, social and governance (ESG) issues that could affect the Project and thus the design. These potential ESG issues are then screened against environmental, social, commercial and technical criteria to understand the most material potential issues to the Project across the triple bottom line of economy, environment and society. Materiality assessments set the foundations for how sustainability will be addressed in subsequent phases and can be updated as the project evolves. Key data sources are contained in the Sustainability Assessment and a summary of the outcomes of the assessment are presented below:

Outcomes

A total of 145 potential material issues were identified, with these consolidated down to 50 potential issues covering the comprehensive list of potential interactions the Project may have with environmental, social or governance considerations. All 50 issues were scored against environmental, social, commercial, technical and strategic criteria. These scores were validated against stakeholder engagement outcomes, and through workshops with subject matter experts in the technical, commercial, strategic, social performance and environmental disciplines, and the Consortium partners. The most material sustainability issues (of the 50 issues identified), are presented in Table 56 below.

Table 56: The most material sustainability issues for the CQ-H_2 Project

	Potential issues
Highly material	• Water availability • Water management • Technological readiness / efficiency confidence • Renewable energy sourcing and security
Material	• Impacts to the Great Barrier Reef Marine Park • Modification of natural water course • Terrestrial biodiversity • Fire and explosion hazard

Existing and planned controls

Existing and planned controls were also scoped, for the purpose of addressing Project issues categorised as “highly material” and “material”.

Conclusions

The Sustainability Assessment identifies and articulates sustainability as a key driver for the Project. Sustainability is a key component of the entire project rationale, which supports four sustainable development goals around energy transition, economic development and decarbonisation. While there are many positive contributions to the UN 2030 agenda for sustainable development, the Project also has potential exposure to sustainability risks, which are intrinsically linked to technical and commercial risks.

The framing workshop conducted at the commencement of the Feasibility Study confirmed the context, sustainability objectives and key sustainability drivers for the Project. These included financial incentives, social licence, regulatory and project efficiency incentives. A desire to have a net-positive contribution not only to the Gladstone region but to the Australian and global decarbonisation landscape was also a key driver for sustainability integration. Government regulations, leadership support, transitioning markets and innovation were all identified as key enablers for positive sustainability outcomes, while physical risks like water scarcity and location constraints, as well as market volatility were identified as potential constraints.

The Materiality Assessment highlighted key sustainability issues for the Project going forward. These issues have the potential to cause significant barriers to delivery, significant cost and/or schedule implications and reputational impacts and should be carefully addressed throughout the life of the Project. The most impactful way to carry the outcomes of this assessment forward into future phases of the Project would be to establish a **sustainability framework** that embeds sustainability considerations into design and procurement first, and then construction, operations and decommissioning.

9.7 Social Performance and Stakeholder Engagement during FEED

In terms of next steps, the following recommendations are made to support the social performance and stakeholder engagement of the Project through to FEED and beyond:

- Stakeholder engagement
- First Nations engagement
- Stakeholder Engagement Framework updated to support FEED.
- Further refine and implement a grievance mechanism.
- Update the social baseline to reflect the 2021 Census results.
    - Update the **social impact assessment** to include impacts associated with Phase 2, decommissioning and closure.
- Prepare a **Social Impact management Plan** (SIMP).
- Prepare **Local and First Nations Participation Plan** (LFNPP)
- Prepare a **Social Investment Strategy** (SIS)
- Major Project contractors to develop and implement **community health, wellbeing, and safety plans** for construction and operations.

To support social performance and stakeholder engagement resource planning for the Project through FEED and beyond, it is recommended that a **Social Project Execution Plan** be prepared.

10 Reduction in carbon footprint

The carbon emissions reduction was estimated for the Project.

The assessment involved comparison of the GHG intensity of the hydrogen production process to be undertaken by the Project and the intensity of production via natural gas reforming and coal gasification.

The GHG emissions intensity of the CQ-H_2 Project is considered to be 0 kg CO_2e / kg H_2.

The estimated emissions reduction (in kilotonnes of carbon dioxide emissions per annum) from the Project are 294 ktpa CO_2e for Phase 1 and 2,442 ktpa CO_2e for Phase 1+2 combined, compared to hydrogen produced by natural gas reforming. Under the scenario where the hydrogen produced is displacing hydrogen produced by coal gasification, the emissions reduction is greatly increased, with estimated reductions of 667 ktpa CO_2e for Phase 1 and 5,543 ktpa CO_2e for Phase 1+2 combined.

The production of renewable hydrogen will also assist in decarbonising Scope 1, 2 and 3 emissions across domestic and international industries.

11 Phase 1 execution strategy

The execution strategy of Phase 1 will involve advancement of the Project through the following stages:

- FEED
- FID
- Detailed design, construction, commissioning.

Contingent on successful progression through the above, the Project will commence operations.

Detail on FEED (including budget and funding), execution considerations, contracting & procurement and the plan to financial close (FID and project delivery) is provided below.

11.1 Front End Engineering and Design (FEED)

11.1.1 FEED overview

FEED introduction

A plan for Front End Engineering and Design (FEED) has been developed for Phase 1 of the Project, with consideration given to Phase 2 where applicable. At a high-level, the FEED plan describes/demonstrates:

- How FEED will be managed, resourced, and scheduled;
- The scope of work for each workstream;
- The critical path on a master schedule;
- How the Project team will report on progress;
- The deliverables to be produced and the timeframes;
- The conditions precedent for the Final Investment Decision (FID).

Steering Committee

A Steering Committee will be established for the oversight and governance of the FEED Study and will act as a decision-making and endorsement body for all significant matters relating to the FEED Study. A monthly FEED report will be compiled by the FEED project team and distributed to each Consortium partner that will consolidate the project performance, schedule and cost information.

The make-up of the Steering Committee will be as follows:

- Stanwell and Iwatani to each appoint a Project Director;
- The Consortium may consider an independent Chairperson;
- Each Consortium partner to appoint a Steering Committee Member.

Verifications list

A Verifications list has been prepared for FEED. This list details critical elements that need to be confirmed and approved for the Project to progress and is as follows:

Register of contracts	Confirmation of offtaker contract terms	Confirmation of carbon accounting approach and confidence in LGC market
Critical review of master planning schedule fatal flaws	Confirmation of GPC dredging commencement trigger	Confirmation of required electrolyser award date
Confirmation of electrolyser plant arrangement (cf. vendor competition) for Phase 1	Confirmation of Powerlink supply arrangement to Fisherman's Landing e.g., Easement, Schedule, TUoS and GPS	Confirmation of Powerlink supply arrangement to HPF Alodga site e.g., Easement, Schedule, TUoS and GPS
Approval of GAWB water supply agreement	Approach to final 3 km of water supply	Approval for seawater exchange system and brine dilution in outfall
Validate HPF compressor water jacket cooling requirements	Confirmation of HPF#1 and HLF#1 water demand after review of CoC target	Solar farm – 33 vs 275 kV interface; Supply location; Connection criteria; Potential for BTM wind supply and Commercial contract.
Sourcing and geographic distribution of green wind and solar contracts that bridge between Phase 1 and the ultimate development	Confirmation of approach to Phase 2 water supply approach	Confirmation of approach to Phase 2 wastewater disposal approach
Consideration of HPF brine concentration and common user potential	Completion of 'Engage to inform / execute' criteria for electrolyser vendors	Establish a MOF approach for Phase 1 with GPC
Confirm land parcel and commercial terms for HLF site with GPC	Phase 1 plot plan after exploration of stacking of fibreglass MEGCs	Phase 1 plot plan design after exploration of bigger storage compression units (2x100% rather than 10 units)
Confirmation of road access & emergency egress routes	Acceptance to reshape road reserve	Confirmation of required land use offsets associated with Aldoga HPF plot and other easement clearing
Consortium endorsed OEM contracting approach		

FEED process

A detailed FEED will result in fewer design changes, provide a greater certainty of outcome, and help realise strategic objectives. This FEED process will result in a FEED package for the Phase 1 development with consideration given to certain areas of Phase 2 that flow through Phase 1.

FEED objectives

The primary objective of FEED is to continue to advance engineering detail, cost estimation and risk mitigation measures to the point where a FID can be made by the Upstream JV.

Key deliverables expected to be delivered at FEED conclusion are:

- Project Execution Plan (PEP);
- Project Scope definition;
- A "Total installed capital cost" estimate (Class 3 to ±20%) including OPEX and lifecycle cost estimates;
- Risk management plan.

All other FEED deliverables can be considered as subsets of these.

FEED scope

The objective of the Phase 1 FEED is to provide confidence to a Consortium Financial Investment Decision (FID) by:

1. Delivering a AACE Class 3 (±20%) design and cost estimate for Phase 1 of the Project that encompasses:
    - A HPF located at Aldoga (25 km's West of Gladstone), Central QLD capable of producing 100 tpd (annual average) of 99.999% gas hydrogen.
        - The HPF design is to accommodate the outcome of the Early Contractor Involvement (ECI) and competitive tender.
        - The electrolyser licensor/s will be known at start of FEED (during pre-FEED). A list of 10-12 will be initially reduced to 4-6 and then an ECI process will be run with a preferred decision being made by FID to enable an order placement immediately post FID
    - A HLF located at Fisherman's Landing capable of liquefying 100 tpd (annual average) of liquid hydrogen.
    - A gaseous hydrogen pipeline from the HPF to the HLF that is sized to support Phase 2. A pipeline design assurance plan is a specific FEED deliverable.
    - Marine facilities (i.e., loading wharf) at the HLF to permit the safe navigation and mooring of liquid hydrogen bulk carriers.
    - Ship-loading facilities at the HLF to permit the safe loading of liquid hydrogen (LH2) bulk carriers based on Phase 2 anticipated export rates, including verification of existing wharf specification and suitability.
    - Interfacing with GAWB to ensure the provision of sufficient suitable raw water to the HPF & HLF for Phase 1. Design and costing of the appropriate infrastructure.
    - Provision of all necessary raw water and wastewater infrastructure to support reliable Phase 1 operation of the HPF and HLF. Design and costing of the appropriate infrastructure.
    - Identification of Phase 1 early works critical to achieve 2026/2027 schedule.
    - Identification of Phase 2 early works that are prudent to include in Phase 1.
    - Considering further expansion (Phase 3 and 4)
    - Interfacing with DES/GRC to ensure the approved disposal of all wastewater from the HPF & HLF.
    - Design and costing of the appropriate infrastructure.

- Interfacing with Powerlink and Ergon to ensure the provision of sufficient suitable power to the HPF & HLF for Phase 1.
- Provision of all necessary power transmission infrastructure to support reliable Phase 1 operation of the HPF and HLF. Design and costing of the appropriate infrastructure.
- Interfacing with GPC to ensure the appropriate development of an agreed portion of the Fishermans Landing precinct
- Landing development area and associated marine structures and work (marine offloading facility, dredging, etc.)

2. Provision of logistics and transportation services for Phase 1 HPF, pipeline/s, HLF and all associated infrastructure and structures
3. Design verification and utility provider consultation to demonstrate that sufficient resources (land, water and power) are guaranteed to be available for Phase 2.
4. Assurance of sustainability footprint across project
5. Undertaking all necessary Community & Stakeholder engagement in support of both Phase 1 and Phase 2, which includes:
    - HPF Phase 1 & 2 development
    - HPF to HLF hydrogen pipeline
    - HLF Phase 1 & 2 development
    - Liquid hydrogen carrier shipping activities
    - Support to Stanwell in relation to all 3rd party engagements
    - Local content planning
    - Indigenous engagement
    - Social baseline research / community profiling
    - Social impact assessment
    - Social impact management planning
    - Social due diligence against international guidelines
    - Public interest assessment
    - Community needs and aspirations assessment
    - Grievance management
    - Community grants and benefit sharing
6. Environmental studies for all aspects Phase 1 and Phase 2 – HPF and HLF, including:
    - Emissions modelling
    - Development and implementation of the Principal's EMPs
    - Site inspections/audits
    - Any additional studies/monitoring required to comply with development approvals
7. Obtaining all necessary and required approvals (regional, state and federal) to permit the commencement of both the Phase 1 operations by Q3 2026 and the Phase 2 operations by Q4 2030.
8. Developing a Level 2 FEED schedule that includes:
    - The required timing of stakeholders' contributions (i.e., GPC, GAWB, GRC, DES, OEMs, local communities, etc.).

- Identification of Phase 2 early works to meet the RFSU date.

9. Develop commercial and financial agreements for execution on FID:
    - Negotiate project structuring
    - Negotiate funding arrangements
    - Assess tax and accounting treatments
    - Negotiate power and water supply agreements
    - Negotiate land and port agreements
    - Negotiate offtake agreements
10. Full range of procurement planning and delivery functions, including:
    - Early works EPCM (i.e., wharf, liquid hydrogen pipeline, power supply infrastructure) FEED Early works identification and definition (i.e., wharf, liquid hydrogen pipeline, power supply infrastructure)
    - Engage with the EPC/M market requesting Expressions of Interest, Prequalification then firm proposals for post-FID fabrication and construction phases including scope preparation and technical evaluations.
    - Contractor tender support (i.e., ensuring social performance commitments are included in contracts).
11. All Phase 1 related HSE systems and plans to support in-field and on-site activities:
    - Industrial relations systems and plans to accommodate Phase 1 and Phase 2
    - Development and validation of Phase 1 construction and commissioning plans
12. Development, submission and implementation of a Document and Information Management Plan
13. Development of post-FEED schedule to Phase 1 commissioning and Ready for Start Up (RFSU) (Q4 2026)

Bridging to FEED activities

It is proposed a number of key bridging activities that are beneficial to continue between Feasibility completion (May 2022) and FEED commencement (Q3 2022) be undertaken to help maintain Project momentum and preserve the overall schedule. Work on these activities will help to add further definition to the Project and will ensure the FEED phase can start more efficiently and effectively. It is proposed to engage the Feasibility consultant to provide the Bridging team.

Key pre-FEED activities will include:

- Electrolyser LCOH and Original Equipment Manufacturer (OEM) engagement (preparation for and issuance of Request For Proposal (RFP) from electrolyser OEM vendors and review of proposals)
- Framing workshop for stakeholder alignment and setting up FEED for success
- Continuation of execution and contracting strategies development
- Continuation of Construction Methodology development (including Modularisation-offsite review and Transport and Logistics study)
- Continuation of Social/Stakeholder engagement, permitting and regulatory works including ongoing engagement with the regulators
- Identification/development of Project Technical Specifications to fill known gaps (e.g., hydrogen, pipelines, equipment, etc.)

- Revise FEED Statement of Work (SOW) and Basis of Design document
- Continue key work on HPF plot layout, module arrangements, etc.
- SOW preparation, solicitation and engagement for Site Survey Phase 1 (Geotech and LiDAR) for the proposed HPF, HLF plots, pipeline routes, Wharf and MOF (as relevant)
- WBS definition, document numbering definition, and Engineering Systems setup for Phase 1 FEED.

Assurance & Compliance

The objective of assurance and compliance activities are to identify, analyse and document any risks and opportunities associated with Stanwell's CQ-H2 Project FEED Stage, in accordance with Stanwell's Risk Management Policy and Framework (which adopts the principles of ISO:31000 (2018) and COSO ERM – Integrating with Strategy and Performance (2017)).

Areas of consideration pertaining to assurance and compliance include:

- Risk Management Methodology
- Risk Evaluation Matrix
- Risk Appetite
- Three Lines of Defence Model
- Risk Management Approach (including Project Delivery Risks and FEED Study Risks (Technical, Commercial and Engagement Risks)
- Risk Management Process & Deliverables
- Project Risk Register
- Responsibilities

Schedule (provisional)

Key to successful FEED execution will be preparation of an Integrated Master Schedule, which forms the basis of the overall Integrated Project Delivery. The sub-schedules within the Integrated Master Schedule include:

- Approvals & Permitting requirements
- GPC activities – dredging, land-forming, associated stakeholder engagements, etc.
- GAWB activities – Phase 1 & 2 agreements and allocation confirmation
- Powerlink – Phase 1 infrastructure
- Powerlink – Phase 2 infrastructure

A FEED schedule is in development and will be updated to reflect the final execution strategies (amount of off-site modularisation, method of contract administration (EPC/EPCM/D&C), etc.) which will be defined during the early stage of FEED. The subsequent Master Project schedule will become the basis of how the project is executed, controlled and progressed.

11.1.2 FEED budget

The budget for FEED is currently being determined and will be finalised prior to commencement of any activities associated with the FEED Study.

The FEED budget was developed based on the work stream structure for the project, namely technical, commercial, stakeholder, and project management workstreams with inclusions for external delivery and governance support.

This budget is based on Advisian cost estimates and compares favourably to its benchmarks for projects of this size and type. Allowance has been made for the evaluation of additional technical and commercial opportunities, and governance activities for peer review of fundamental design and cost aspects of the reference project.

11.1.3 FEED funding

The FEED Study contributions (both cash and in-kind) will be determined prior to commencement of any activities associated with the FEED Study.

All partners have indicated an interest in seeing the Project proceed to final completion, subject to passing relevant stage gates.

Contributions to the FEED Study will be formalised via a MOU that is currently under development.

A summary of indicative participant roles during FEED is provided below.

Table 57: Summary of Participant Roles

Company	FEED Study Role
Stanwell	• Australian study lead • Energy, electrolysis lead • Project development lead (infrastructure, planning, approvals)
APA	• Australian infrastructure group • Pipeline lead • Approvals support • Advice on study approach • Information gathering through local networks • Information on infrastructure specifications and costs
Iwatani	• Japan consortium and study lead • Liquefaction integration lead • Electrolysis support
KEPCO	• Providing adequate advice and information from the off-taker's perspective
Marubeni	• Commercial and finance lead • Advice on study approach • Information gathering through local networks • Information on Japanese off-takers • Advice on procurement contracts • Advice on project structuring • Advice on insurance
KHI	• Engineering including estimation and Schedule for liquefaction facilities, storage tank, liquefied hydrogen carriers • Information on equipment specifications and costs

The partners will contribute resources to a project management team for the Project FEED Study, overseen by a joint Project Steering Committee. The Project will be supported by a range of technical and commercial advisors which will be engaged under Stanwell's professional services and engineering panels. These advisors include:

- Worley/Advisian – Technical advisory
- Deloitte – Commercial and Financial advisory
- Advisian – Stakeholder advisory
- MinterEllison – Legal advisory (other advisors will be engaged in the event of potential conflicts of interest).

11.2 Contracting and Procurement

An indicative outline of the Procurement and Contracting Strategy during FEED is provided in this section. The Strategy covers the HPF and associated services and infrastructure. The Strategy must remain flexible and agile to enable adaptation to the changing nature of the Project.

Project governance requirements

The requirements of the Queensland Procurement Policy 2021 (QPP) requirements must be followed for all procurement activities utilising public monies and therefore apply to all activities under this Project, including the application of the Best Practice Principles (BPP) and Best Practice Industry Conditions (BPICs) where applicable.

Procurement activities and timeframes

A high-level overview of the activities and estimated timeframes are outlined in the table below:

Table 58: Procurement activities and indicative timeframes

Stage	Activity	Proposed Timing
Pre-FEED	Roll-over of the following advisors: • Technical Advisor • Stakeholder engagement Advisor • Financial/Commercial Advisor	June 2022
	Probity Advisor	June – July 2022
	Legal Advisor	June – July 2022
	ECI for Construction Contractor/s	June – July 2022
Pre-FEED & FEED	ECI for OEM Electrolyser	July 2022 onwards
FEED	OEM Electrolyser Shortlisting	July 2022 onwards
	Any other OEM Engagement	September onwards 2022
	EPCM Procurement	January/February 2023 to June 2023

Engagement with Equipment OEMs during FEED

Engagement with various OEMs who will be providing key plant will be necessary during FEED. All Vendor/Contractor engagements will be led by Stanwell Procurement with support provided by the Technical Advisor.

Procurement Plan for Long Lead Items

Long Lead Items (LLIs) are those items which require the longest timeframe from purchase orders (POs) placement to delivery. They require an early procurement focus to place the POs as soon as possible to mitigate project schedule impacts. A LLI list will be developed for each area of project scope.

Engagement with Construction Contractors during FEED

It will be necessary to identify a suitable early engagement with at least one construction contractor organisation to support preparation of documentation to support the FEED cost estimate. Scopes of work will need to be prepared for the different construction areas, however these cannot be progressed until an appropriate level of detailed project definition exists and can only be matured during the execution stage. Collaborative Contracting is currently being explored with Queensland Major Construction Association (QMCA) to facilitate appropriate early engagement with Construction contractors for FEED.

EPCM Approach

The engineering procurement and construction management (EPCM) strategy for project execution is shown in the figure below.

11.3 Plan to Financial Close (FID and project delivery)

After successful completion of FEED, each consortium partner will be provided the opportunity to present the results to their board and get the necessary approval for FID. The study will also be provided to interested funding/financing partners for their approvals.

Once all the individual board decisions have been made, a SteerCo will be held to:

- Make a decision to proceed to FID if all board approvals are granted; or
- Approve necessary next steps to address any issues that a board or funding institution may have flagged to get the necessary approvals for FID.

Once FID has been achieved and the project sanctioned, the Consortium partners execute the agreements negotiated during FEED and the project proceeds to financial close. These include Joint Venture Agreements, Offtake Agreements, EPC contracting, Leases, Permits, etc.

To close out the FEED, the following tasks will be required:

- A thorough cost/expenses reconciliation process will be undertaken to ensure all consortium members are made whole at the end of FEED.
- Necessary audits will be conducted (ARENA funding requirements)
- lessons learned workshop
- Project closeout meeting

12 Phase 2 pathway

The CQ-H_2 Project is focused on achieving the completion (production operations) of Phase 1 in late 2026 (with delivery of liquefied hydrogen to Japan in early 2027). Phase 2 operations will commence in 2031, which will involve a scale-up of Phase 1, with a 700 tpd increase in hydrogen production from 100 tpd to 800 tpd.

The Project has been assessed in concept for Phase 2, with considerations and requirements for this phase being included in decisions pertaining to Phase 1 where applicable. Phase 2 will be further developed during the FEED stage. FEED and EPC activities pertaining to Phase 2 will be undertaken following Phase 1 execution. Planning activities for Phase 2 execution will also occur following commencement of Phase 1 operations. The Phase 2 pathway includes following:

Technical workstream

- Advancement of Phase 2 Project components (from Concept to Feasibility, and into FEED and EPC), including:
    - Location, land (including civil earthworks) and plot plans for the HPF and HLF
    - Electrolysis and compression technology at the HPF
    - Hydrogen storage at the HPF
    - HLF receiving facilities
    - Power supply
    - Water supply and treatment
    - Wastewater management
    - HPF and HLF cooling.
- Revision of the RAP to include regulatory approvals for Phase 2 of the Project and completion of regulatory approvals applications (including planning and environmental approvals) and agreements (including ILUA for Native Title, Cultural Heritage and Tenure).
- Revision of the RMP to include risk identification and mitigation actions for Phase 2 of the Project.

Commercial workstream

- The Phase 2 commercial pathway will be driven by firm offtake arrangements supported by the execution of binding long-term offtake agreements for the Phase 2 production volume.
- Phase 2 is expected to be a commercially driven project and it is unlikely that significant grant and concessional debt funding will be available. Consequently, commercial debt providers will be critical. In assessing the potential metrics for Phase 2 HPF, $2.5 billion of concessional debt and $1.5 billion of commercial has been assumed.
- Phase 2 is expected to be delivered within the existing IJV structures incorporated as part of Phase 1, or a new IJV will be incorporated for the Phase 2 HPF.
- In addition to legal and commercial considerations, Phase 2 structuring will depend on the tax profile of investors that may wish to participate in Phase 2, and also the anticipated tax profile of the Phase 2 operations.
- In the light of this, the Phase 2 structuring will be considered in further detail once the likely profile of Phase 2 investors is known, and further refinements of the financial model are made in the FEED stage.
- The hydrogen pipeline is assumed to be constructed in Phase 1 and continues to operate until the end of the project without additional capital or operating costs incurred in Phase 2.

- Other arrangements such as loading facilities, wharf and shipping will be sized and constructed for Phase 2 requirements

Strategic workstream

- Ongoing stakeholder engagement, including First Nations engagement
- Review of frameworks, plans, strategies and grievance mechanism for Phase 2 (and updating if changes are required), including:
    - ***Frameworks:*** Sustainability Framework, Stakeholder Engagement Framework (inclusive of First Nations Engagement Framework and Community Education Framework)
    - ***Plans:*** Social Project Execution Plan, Social Impact Management Plan, Local and First Nations Participation Plan, Community Health, Wellbeing, and Safety Plans [Major Project contractors]
    - ***Strategies:*** Social Investment Strategy
    - ***Other:*** Social Baseline, Stakeholder Mapping and Issues Analysis, other applicable social/stakeholder workstream activities

13 Conclusions and next steps

13.1 Conclusions

The Feasibility Study concluded that the CQ-H_2 Project is technically feasible. The Study also concluded that the Project has the potential to be commercially viable and capable of generating a commercial rate of return for investors. Phase 1 is in effect a commercial demonstration scaled project. With adequate (government) support it is capable of making moderate returns for the equity partners. In phase 2 the shift in technology, project costs and scale will create the conditions for the project to be fully commercial in its own right.

Furthermore, the Study concluded that the social, stakeholder and associated impacts of the Project will be positive.

The study conclusions and findings are as follows:

Technical Feasibility

- The Project is technically feasible, with appropriate industrial land secured and suitable power supply (renewable energy in the form of solar and wind (supplemented by large-scale generation certificates where required) via BTM and NEM connections), water supply and treatment, cooling and wastewater disposal solutions. Furthermore, there are no major project limiting impacts associated with regulatory approvals.

Commercial Feasibility

- The Project is potentially commercially viable at the proposed scale for phase 1 with appropriate Government support. Phase 2 is commercially viable as an independent standalone project.
- An IJV was identified as the preferred structure for the Project.
- The modelled Levelised Cost of Gaseous Hydrogen (LCOGH) in AUD$/kg (USD $/kg with USD=0.71AUD) is as follows:

Table 59: Levelised Cost of Gaseous Hydrogen (LCOGH)

LCOGH pre-tax without grants	Base	Optimised	Stretch
Phase 1	$5.76 ($4.09)	$4.89 ($3.47)	$4.65 ($3.30)
Phase 2 incremental	$4.25 ($3.01)	$3.38 ($2.40)	$2.79 ($1.98)

- The modelled Levelised Cost of Liquefied Hydrogen (LCOLH) is as follows:

Table 60: Levelised Cost of Liquefied Hydrogen (LCOLH)

LCOLH pre-tax without grants	Base	Optimised	Stretch
Phase 1	$19.19 ($13.63)	$17.51 ($12.43)	$16.99 ($12.06)
Phase 2 incremental	$7.95 ($5.65)	$6.74 ($4.78)	$5.99 ($4.25)

Stakeholder and social Feasibility

- The Project achieves strategic alignment with the policies of the Australian and Queensland Governments.
- Consortium partners meet key supply chain objectives of price, timing and volumes.
- No major project impediments were identified in the social/stakeholder engagement and assessments undertaken
- Furthermore, it is anticipated that Native Title and Cultural Heritage will be satisfactorily addressed for the Project, and that tenure (with respect to the hydrogen pipeline) will be able to be obtained.

The analysis undertaken supports progression to Front-End Engineering and Design (FEED). The FEED stage will refine the design and project performance metrics and detail the Project parameters (such as cost confidence to +/- 30%), establish commercial agreements for supply, supporting ancilliaries and offtake to support a Final Investment Decision (FID).

13.2 Next steps

CQ-H_2 is a large-scale green hydrogen project which will help launch a new low-carbon export industry for Australia and underpin a green hydrogen hub in the industrial heart of Gladstone.

Through partnering with a highly credible consortium of Japanese and Australian companies, and with strong backing from all levels of government, Phase 1 of the project will commence export of 100 tonnes per day of liquefied green hydrogen export from Central Queensland to Japan from 2027. Full commercialisation (Phase 2) will see the project grow to a total of 800 tonnes per day from 2031.

The CQ-H_2 Consortium is made up of six companies with expertise across the supply chain. The Consortium has shared project costs to date and has a high level of commitment to progress to project execution, including investing in project development and equity.

Unlocking the economic viability of green hydrogen will require staged deployment of large-scale projects to drive down costs, improve technology and activate markets. In the initial stages, while costs are still high, long-term commercial hydrogen offtake is unlikely to be available so it will be critical for companies and governments to share cost and risk through a mix of equity and grant funding.

At a high-level, the activities completed to date (which will be advanced through next steps) are as follows:

Project development maturity

- Detailed Feasibility study completed
- Class 4 (±30%) capital and operating cost estimates and design completed
- Energy: 100% renewable energy supply strategy developed, agreements with renewable energy projects executed / under development
- Land for hydrogen production facility secured in the Gladstone State Development Area
- Water: efficiency opportunities scoped, water supply contract developed
- Port: detailed studies underway with Gladstone Ports Corporation
- Transmission: short form assessment completed by Powerlink, connection inquiry and application to be lodged in coming months
- Detailed Regulatory Approvals Pathway prepared, applications due to be lodged in Q3 2022
- Gladstone community engagement and social impact assessment framework completed.

- Strong support from a wide range of local, state and federal stakeholders.
- Detailed pathway to Final Investment Decision, including FEED plan, developed.

Partnership and Offtake

- High level of consortium commitment to move to FEED and project execution
- Multiple potential offtakers identified in the CQ-H_2 Consortium
- Detailed hydrogen offtake agreements have been developed by MinterEllison and negotiation has commenced with offtakers
- Domestic offtake – a domestic partnership arrangement is being established. If this is executed, it would enable heavy transport domestic hydrogen offtake from the CQ-H_2 site.

Government support and funding

The Project is undertaking activities to further its engagement with government to improve understanding of the Project and seek additional grant funding for the purpose of supporting the project economics.

The next step in the Project involves review and evaluation by Consortium members of this Feasibility Study report and associated supporting information (including Feasibility Study outcomes and the FEED Plan), to enable a decision on progression to FEED.

Should the decision be made to advance to FEED, an MOU will be executed between the Consortium partners that will outline FEED Study roles and financial and in-kind contributions. In the interim period, pre-FEED bridging activities (including a planning phase) will be implemented.

14 Project Data Summary

ARENA information requirements include a number of modelling outputs that provide a more granular set of information over the supply chain. This information is provided below for the Base Case for each of Phase 1 and Phase 2

14.1 Levelised Cost of Hydrogen (LCOH) Phase 1 Base Case

HPF – Levelised Cost of Gaseous Hydrogen (LCOGH)	$ AUD per kg	% of total
Expensed development costs	$0.01	0%
Initial capital costs	$2.47	44%
Lifecycle capital cost	$0.08	1%
Fixed non-labour operating costs	$0.07	1%
Variable labour operating costs	$0.16	3%
Electricity costs	$2.75	49%
Water costs	$0.02	0%
Other variable non-labour operating costs	-	0%
Total LCOGH from HPF	$5.57	100%

Levelised Costs of Liquified Hydrogen (LCOLH) by cost categories	$ AUD per kg	% of total
Total project LCOLH including shipping & receiving	$19.19	100 %

LCOLH by supply chain components	$ AUD per kg	% of total
Hydrogen plant	$7.07	37%
Hydrogen pipeline	$0.24	1%
Total Shipping	$11.88	61%
Total project LCOH including shipping & receiving	$19.19	100%

14.1.1 Project Data

Production/delivery	Unit	Total production/delivery over the asset life	Average production/delivery p.a. (of fully operating years)
Hydrogen plant	kg	1,122,522,175	33,016,083
Hydrogen pipeline	kg	1,122,522,175	33,016,083
Liquefaction plant	kg	1,100,050,605	32,355,140
Shipping & Receiving	kg	883,189,105	25,884,112

Offtake revenue	Total offtake revenue ($FY2022 Real AUD millions)	Total offtake revenue ($Nominal AUD millions)	Total offtake revenue ($NPV AUD millions)	Offtake revenue per total production/delivery over the asset life ($Nominal AUD/kg)
Hydrogen plant	$4,524	$7,284	$1,420	$6.49
Hydrogen pipeline	$189	$304	$59	$0.27
Liquefaction plant	$10,766	$17,337	$3,382	$15.76
Shipping & Receiving	$2,845	$4,581	$892	$5.19

Whole of life project costs	$FY2022 Real AUD (million)	$Nominal AUD (million)	$PV AUD (million)
Hydrogen plant			
Initial capital costs	$1,101	$1,182	$870
Lifecycle capital cost	$86	$126	$29
Electricity costs	$3,148	$5,111	$969
Fixed operating costs	$79	$124	$28
Variable operating costs	$211	$339	$66
Total Hydrogen plant	$4,626	$6,882	$1,962
Hydrogen pipeline			
Initial capital costs	$80	$86	$63
Lifecycle capital cost	-	-	-
Electricity costs	-	-	-
Fixed operating costs	$15	$23	$5
Variable operating costs	-	-	-
Total Hydrogen pipeline	$94	$109	$68
Total Shipping & Receiving	$6,115	$8,356	$3,296
Total Costs	**$10,834**	**$15,348**	**$5,326**

Cost per production/delivery over the asset life ($/kg)	$FY2022 Real AUD/kg	$Nominal AUD/kg
Hydrogen plant		
Initial capital costs	$0.98	$1.05
Lifecycle capital cost	$0.08	$0.11
Electricity costs	$2.80	$4.55
Fixed operating costs	$0.07	$0.11
Variable operating costs	$0.19	$0.30
Total Hydrogen plant	$4.12	$6.13
Hydrogen pipeline		
Initial capital costs	$0.07	$0.08
Lifecycle capital cost	-	-
Electricity costs	-	-
Fixed operating costs	$0.01	$0.02
Variable operating costs	-	-
Total Hydrogen pipeline	$0.08	$0.10
Total Shipping & Receiving	$5.87	$7.99
Total costs per production/delivery over the asset life ($/kg)	**$10.08**	**$14.23**

14.1.2 Hydrogen Plant – Electrolyser & Balance of Plant

Electrolyser data	Unit	Value
Gaseous hydrogen production over asset life	H_2kg	1,122,522,175
Capacity factor (first 12 months of operation)	%	90%
Average operating hours p.a. (of full operating years)	Hours	7,924
Stack replacement interval	Hours	70,000
Asset life	Years	9

Capital expenditure (millions)	$FY2022 Real AUD	$Nominal AUD	$NPV AUD
Initial capital costs			
Land cost	$7	$7	$6
Electrolyser	$494	$530	$390
Storage equipment capital capex	-	-	-
Compression equipment capex	-	-	-
Electricity network capex	-	-	-
Balance of plant	$600	$644	$473
Total Initial capital costs	$1,101	$1,182	$870
Lifecycle capital costs			
Electrolyser	$86	$126	$29
Storage equipment capital capex	-	-	-
Compression equipment capex	-	-	-
Electricity network capex	-	-	-
Balance of plant	-	-	-
Total Lifecycle capital costs	$86	$126	$29
Total capital expenditure	**$1,187**	**$1,308**	**$899**

Capex per production/delivery over the asset life ($/kg)	$FY2022 Real AUD/kg	$Nominal AUD/kg
Initial capital costs		
Land cost	$0.01	$0.01
Electrolyser	$0.44	$0.47
Storage equipment capital capex	-	-
Compression equipment capex	-	-
Electricity network capex	-	-
Balance of plant	$0.53	$0.57
Total Initial capital costs	$0.98	$1.05
Lifecycle capital costs		
Electrolyser	$0.08	$0.11
Storage equipment capital capex	-	-
Compression equipment capex	-	-
Electricity network capex	-	-
Balance of plant	-	-
Total Lifecycle capital costs	$0.08	$0.11
Total capital expenditure	**$1.06**	**$1.17**

Operating expenditure (millions)	$FY2022 Real AUD	$Nominal AUD	$NPV AUD
Electrolyser			
Expensed development costs	-	-	-
Fixed non-labour operating costs	$25	$41	$8
Variable labour operating costs	-	-	-
Electricity costs	$3,048	$4,950	$938
Water costs	$28	$45	$9
Other variable non-labour operating costs	-	-	-
Total Electrolyser	$3,101	$5,035	$954
Balance of plant			
Expensed development costs	$5	$5	$5
Fixed non-labour operating costs	$49	$78	$15
Variable labour operating costs	$183	$295	$57
Electricity costs	$101	$162	$31
Total Balance of plant	$337	$539	$109
Total operating expenditure	**$3,438**	**$5,574**	**$1,063**

Opex per production/delivery over the asset life ($/kg)	$FY2022 Real AUD/kg	$Nominal AUD/kg
Electrolyser		
Expensed development costs	-	-
Fixed non-labour operating costs	$0.02	$0.04
Variable labour operating costs	-	-
Electricity costs	$2.72	$4.41
Water costs	$0.02	$0.04
Other variable non-labour operating costs	-	-
Total Electrolyser	$2.76	$4.49
Balance of plant		
Expensed development costs	$0.00	$0.00
Fixed non-labour operating costs	$0.04	$0.07
Variable labour operating costs	$0.16	$0.26
Electricity costs	$0.09	$0.14
Total Balance of plant	$0.30	$0.48
Total operating expenditure	**$3.06**	**$4.97**

14.1.3 Electricity

Electricity costs over whole asset life (millions)	$FY2022 Real AUD	$Nominal AUD	$NPV AUD
Total electricity costs over whole asset life (millions)	$4,299	$6,965	$1330

14.1.4 Water

Water costs over whole asset life (millions)	$FY2022 Real AUD	$Nominal AUD	$NPV AUD
Total water costs over whole asset life (millions)	$86	$139	$27

14.1.5 Resourcing

Full Time Employee (FTE)	Unit	Value
Hydrogen plant		
FTE during construction and operation period	#	326.13
Hydrogen pipeline		
FTE during construction and operation period	#	31
Liquefaction plant		
FTE during construction and operation period	#	264

14.2 Levelised Cost of Hydrogen (LCOH) Phase 2 Base Case

HPF – Levelised Cost of Gaseous Hydrogen (LCOGH)	$ AUD per kg	% of total
Expensed development costs	-	0%
Initial capital costs	$1.70	40%
Lifecycle capital cost	$0.09	2%
Fixed non-labour operating costs	$0.04	1%
Variable labour operating costs	$0.01	0%
Electricity costs	$2.39	56%
Water costs	$0.02	1%
Other variable non-labour operating costs	-	0%
Total LCOGH from HPF	$4.25	100%

Levelised Costs of Liquified Hydrogen (LCOLH) by cost categories	$ AUD per kg	% of total
Expensed development costs	-	0%
Initial capital costs	$3.81	48%
Lifecycle capital cost	$0.10	1%
Fixed non-labour operating costs	$0.40	5%
Variable labour operating costs	$0.02	0%
Electricity costs	$3.55	45%
Water costs	$0.07	1%
Other variable non-labour operating costs	-	0%
Total project LCOLH including shipping & receiving	$7.95	100 %

LCOLH by supply chain components	$ AUD per kg	% of total
Hydrogen plant	$4.56	57%
Hydrogen pipeline	-	0%
Shipping & Receiving	$3.40	43%
Total project LCOH including shipping & receiving	$7.95	100%

14.2.1 Project Data

Production/delivery	Unit	Total production/delivery over the asset life	Average production/delivery p.a. (of fully operating years)
Hydrogen plant	kg	7,221,231,454	240,713,775
Hydrogen pipeline	kg	7,221,231,454	240,713,775
Liquefaction plant	kg	7,076,682,266	235,895,347
Shipping & Receiving	kg	6,728,587,108	224,100,580

Offtake revenue	Total offtake revenue ($FY2022 Real AUD millions)	Total offtake revenue ($Nominal AUD millions)	Total offtake revenue ($NPV AUD millions)	Offtake revenue per total production/delivery over the asset life ($Nominal AUD/kg)
Hydrogen plant	$28,163	$47,053	$7,600	$6.52
Hydrogen pipeline	-	-	-	-
Liquefaction plant	$45,351	$75,773	$12,240	$10.71
Shipping & Receiving	$2,571	$4,296	$693	$0.64

Whole of life project costs	$FY2022 Real AUD (million)	$Nominal AUD (million)	$PV AUD (million)
Hydrogen plant			
Initial capital costs	$5,295	$6,176	$3,310
Lifecycle capital cost	$653	$1,035	$179
Electricity costs	$17,448	$29,295	$4,655
Fixed operating costs	$267	$447	$71
Variable operating costs	$221	$369	$60
Total Hydrogen plant	$23,884	$37,322	$8,274
Hydrogen pipeline			
Initial capital costs	-	-	-
Lifecycle capital cost	-	-	-
Electricity costs	-	-	-
Fixed operating costs	-	-	-
Variable operating costs	-	-	-
Total Hydrogen pipeline	-	-	-
Total Shipping & Receiving	$15,089	$22,316	$6,169
Total Costs	**$38,972**	**$59,638**	**$14,443**

Cost per production/delivery over the asset life ($/kg)	$FY2022 Real AUD/kg	$Nominal AUD/kg
Hydrogen plant		
Initial capital costs	$0.73	$0.86
Lifecycle capital cost	$0.09	$0.14
Electricity costs	$2.42	$4.06
Fixed operating costs	$0.04	$0.06
Variable operating costs	$0.03	$0.05
Total Hydrogen plant	$3.31	$5.17
Hydrogen pipeline		
Initial capital costs	-	-
Lifecycle capital cost	-	-
Electricity costs	-	-
Fixed operating costs	-	-
Variable operating costs	-	-
Total Hydrogen pipeline	-	-
Total Shipping & Receiving	$2.14	$3.17
Total costs per production/delivery over the asset life ($/kg)	**$5.45**	**$8.33**

14.2.2 Hydrogen Plant – Electrolyser & Balance of Plant

Electrolyser data	Unit	Value
Gaseous hydrogen production over asset life	H_2kg	7,221,231,454
Capacity factor (first 12 months of operation)	%	94%
Average operating hours p.a. (of full operating years)	Hours	8,253
Stack replacement interval	Hours	70,000
Asset life	Years	8

Capital expenditure (millions)	$FY2022 Real AUD	$Nominal AUD	$NPV AUD
Initial capital costs			
Land cost	-	-	-
Electrolyser	$3,201	$3,734	$2,001
Storage equipment capital capex	-	-	-
Compression equipment capex	-	-	-
Electricity network capex	-	-	-
Balance of plant	$2,094	$2,442	$1,309
Total Initial capital costs	$5,295	$6,176	$3,310
Lifecycle capital costs			
Electrolyser	$653	$1,035	$179
Storage equipment capital capex	-	-	-
Compression equipment capex	-	-	-
Electricity network capex	-	-	-
Balance of plant	-	-	-
Total Lifecycle capital costs	$653	$1,035	$179
Total capital expenditure	**$5,949**	**$7,212**	**$3,489**

Capex per production/delivery over the asset life ($/kg)	$FY2022 Real AUD/kg	$Nominal AUD/kg
Initial capital costs		
Land cost	-	-
Electrolyser	$0.44	$0.52
Storage equipment capital capex	-	-
Compression equipment capex	-	-
Electricity network capex	-	-
Balance of plant	$0.29	$0.34
Total Initial capital costs	$0.73	$0.86
Lifecycle capital costs		
Electrolyser	$0.09	$0.14
Storage equipment capital capex	-	-
Compression equipment capex	-	-
Electricity network capex	-	-
Balance of plant	-	-
Total Lifecycle capital costs	$0.09	$0.14
Total capital expenditure	$0.82	$1.00

Operating expenditure (millions)	$FY2022 Real AUD	$Nominal AUD	$NPV AUD
Electrolyser			
Expensed development costs	-	-	-
Fixed non-labour operating costs	$184	$307	$50
Variable labour operating costs	-	-	-
Electricity costs	$16,668	$27,993	$4,445
Water costs	$170	$284	$46
Other variable non-labour operating costs	-	-	-
Total Electrolyser	$17,022	$28,584	$4,541
Balance of plant			
Expensed development costs	-	-	-
Fixed non-labour operating costs	$83	$140	$21
Variable labour operating costs	$51	$84	$14
Electricity costs	$780	$1,302	$210
Total Balance of plant	$913	$1,526	$245
Total operating expenditure	**$17,935**	**$30,110**	**$4,785**

Opex per production/delivery over the asset life ($/kg)	$FY2022 Real AUD/kg	$Nominal AUD/kg
Electrolyser		
Expensed development costs	-	-
Fixed non-labour operating costs	$0.03	$0.04
Variable labour operating costs	-	-
Electricity costs	$2.31	$3.88
Water costs	$0.02	$0.04
Other variable non-labour operating costs	-	-
Total Electrolyser	$2.36	$3.96
Balance of plant		
Expensed development costs	-	-
Fixed non-labour operating costs	$0.01	$0.02
Variable labour operating costs	$0.01	$0.01
Electricity costs	$0.11	$0.18
Total Balance of plant	$0.13	$0.21
Total operating expenditure	$2.48	$4.17

14.2.3 Electricity

Electricity costs over whole asset life (millions)	$FY2022 Real AUD	$Nominal AUD	$NPV AUD
Total electricity costs over whole asset life (millions)	$24,110	$40,424	$6,453

14.2.4 Water

Water costs over whole asset life (millions)	$FY2022 Real AUD	$Nominal AUD	$NPV AUD
Total costs over whole asset life (millions)	$478	$798	$129

14.2.5 Resourcing

FTE	Unit	Value
Hydrogen plant		
FTE during construction and operation period	#	1257.91
Hydrogen pipeline		
FTE during construction and operation period	#	0
Liquefaction plant		
FTE during construction and operation period	#	794