Department of State Development, Tourism and Innovation

Gladstone and Townsville Hydrogen Opportunities Study

Part 2 Report | November 2020

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1. Introduction and rationale

1.1 Background

This summary report builds on the Gladstone and Townsville Hydrogen Opportunities Study Part 1 report prepared for the Department of State Development, Tourism and Innovation (DSDTI) in response to the *Queensland Hydrogen Industry Strategy 2019-2024;* a five-year plan to grow a sustainable hydrogen industry that supports renewable resources, creates jobs and strengthens Queensland's economy[1].

The Part 1 report reviewed the available literature on hydrogen, case studies and produced a conceptual hydrogen schematic. The report identified international, national, and local hydrogen successes and challenges, and discussed opportunities for the industry in the export and domestic markets. The report identified there will be a number of interrelated criteria that must be met to establish a hydrogen industry in Queensland. This Part 2 report builds on the Part 1 report through the identification, development and refinement of key spatial and physical criteria for the establishment of a hydrogen plant.

1.2 Purpose

The Gladstone and Townsville Hydrogen Opportunities Study Part 2 Report will provide information for consideration by the Queensland Government and assist with integrated land use and ports planning, infrastructure and services corridor planning and programming including the potential for common user infrastructure.

The study considers a hydrogen industry development pathway from demonstration to large scale plants for domestic consumption and export, focusing on the Gladstone and Townsville State Development Areas (SDA). The study also considers:

- The potential for transitional development from brown/grey hydrogen, blue hydrogen to green hydrogen
- The sources of blue and green hydrogen
- The opportunity to integrate with existing fossil fuelled and renewable electricity generation sites.

1.3 Scope and methodology

There are three main reporting stages that form part of this study (see Figure 1-1). Part 1 of this study has been completed. This report forms Part 2. The purpose of Part 2 is to document potential growth opportunities together with the technical and process requirements, the infrastructure, transport and servicing requirements, and the land use planning considerations for the hydrogen industry development pathway within Queensland.

The following tasks have been undertaken as part of Part 2:

- Undertaking consultation with key stakeholders
- Conducting a reference-based desktop market analysis of current and future hydrogen demand
- Synthesising the market analysis into a 'lower end' and 'upper end' estimate
- Overlaying estimated future limiting port logistics

1 Queensland Hydrogen Industry Strategy, State of Queensland 2019-2024

- Developing and identifying the spatial, and infrastructure criteria for the establishment of a hydrogen plant
- Current approval pathways to develop a hydrogen plant in Townsville and Gladstone SDA.

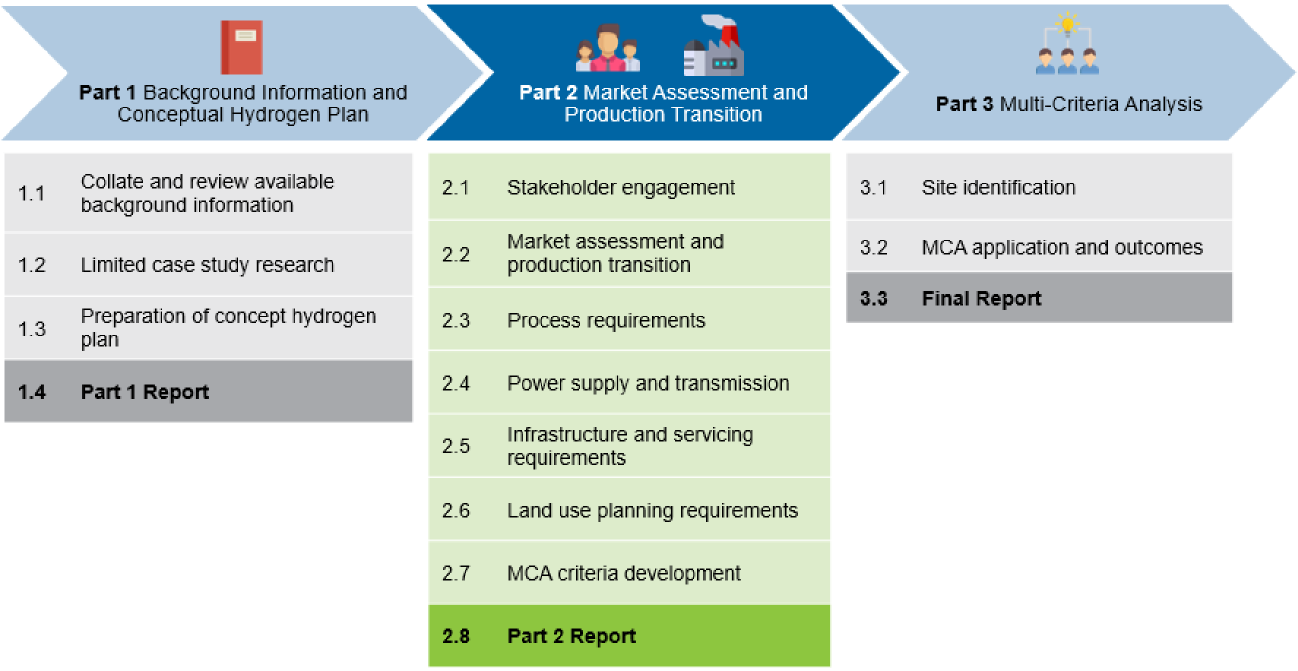

Figure 1-1 Study methodology

1.4 Scope and limitations

This report has been prepared by GHD for Department of State Development, Tourism and Innovation and may be used and relied on by Department of State Development, Tourism and Innovation for the purpose agreed between GHD and the Department of State Development, Tourism and Innovation as set out in Section 1 of this report. This report may be distributed by the Department of State Development, Tourism and Innovation to other State Government agencies.

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The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

Our report has been prepared subject to your acknowledgement that GHD is not qualified and/or accredited to give advice in relation to financial and demand forecasts. The market assessment included in this report is desktop only and completely informed by third party market demand assessments. Forecasted demand volumes are not to be relied on and did not consist of any original market assessment as defined by GHD's proposed scope of works.

2. Stakeholder consultation

In line with DSDTI's request, GHD integrated stakeholder consultation into the Task 2 methodology to capture the industry's knowledge and perceived and real challenges for an emerging hydrogen industry in Queensland. The following section of the report provides an overview and analysis of the results from the stakeholder consultation undertaken.

2.1 Methodology overview

Stakeholder consultation involved online consultation using a standard set of questions for government agencies, hydrogen producers and exporters, ports and logistics, and infrastructure owners / operators. A total of 30 stakeholders were invited to participate in the stakeholder consultation process.

To gain a deeper understanding of the industry's knowledge and perception of a future hydrogen industry in Queensland, 22 hydrogen producers or proponents were consulted in May 2020. A total of 4 responses were received for the online consultation, representing a response rate of 16%.

In addition to the online consultation, GHD consulted with stakeholders from State Agencies, Local Councils, Gladstone Port Corporation, and the Port of Townville, via telephone meetings or email questionnaire,

The following section of the report provides an analysis of the results from the consultation.

2.2 Analysis

Key findings from the online consultation are detailed below:

- Stakeholders identified that Queensland has a number of key regional strengths to support the development of a hydrogen production and export industry. These include **good renewable energy resources, experience in supporting large scale industry development**, as well as the availability of **well serviced industrial land**, (water and transport), with the potential for colocation of industrial uses. The acknowledgement that there is an established highly skilled local workforce (from LNG industry) within the region, and an anecdotal evidence of support for local industry were also identified as regional strengths.
- In contrast, stakeholders perceived actual **energy cost / availability for large scale development**, **constrained electricity transmission infrastructure and existing port facilities' capabilities** as the greatest regional challenges / constraints that may inhibit the development of hydrogen production and export in Queensland. It was also identified that the lack of an agreed upon approach by government and private sector in investment for the industry and supporting infrastructure may limit the development of large-scale plants for export and domestic markets. The cost competitiveness of the current industry, against traditional fossil fuel power generation was also identified as a challenge.
- Stakeholders consider **water for hydrogen production is the most important supporting infrastructure for a hydrogen facility**. Power distribution, power generation (renewables – wind, solar) and port infrastructure were considered the second-most important supporting infrastructure. This reinforces respondent's perception on supporting infrastructure's proximity to a hydrogen facility. Water for hydrogen production and power distribution are considered the supporting infrastructure that should be the closest to support the development of a hydrogen facility.

- There are mixed views on the new safety standards for hydrogen in Australia, however, stakeholders emphasised the importance of ensuring safety standards did not create unnecessary, artificial barriers to entry. There was general acknowledgement that the LNG standards that are being applied may be suitable as an interim measure, however specific industry standards should be developed, more reflective of a hydrogen plant's likely hazards.
- Stakeholders intend to produce hydrogen for domestic use including feedstock for local ammonia and transport. However, it is more widely perceived that the export market is where hydrogen demand would be generated and provide the most benefit and interest from external investors.
- Stakeholders perceived most other industrial uses (for example: high purity oxygen, chemical production, ore processing) as synergistic to hydrogen operations.
- Separation distances are considered to be required to be incorporated internally into plant layout, consistent with existing requirements such as major hazard facilities and LNG plants.
- The minimum size of land required for viable hydrogen production and storage varies, dependent on co-location of components and project specifics. Co-location of components (for example: hydrogen and liquefaction) was considered important by most stakeholders.
- Stakeholders anticipate large scale port capacity and infrastructure will be required to meet export demand for hydrogen. It is generally understood that new reclaimed land with a new berth may be necessary.
- At this stage, stakeholders do not anticipate any specific requirements / restrictions for the road transport of hydrogen.
- For the production of hydrogen, supply chain linkages to water, electricity and offtake are considered important.
- There are a range of opportunities identified from the various derivatives of hydrogen including oxygen, green hydrogen, and mineral and chemical production.
- Solar, wind and natural gas are perceived by stakeholders are the most viable feedstock options, while pumped hydro and biomass are perceived as the least viable. Responses from stakeholders demonstrate cost is a large driver.
- The demand for hydrogen is not expected to change / shift in the context of current global uncertainties (COVID - 19).

Overall, stakeholders identified a need for the industry to be able to scale up to respond to changes in demand. This will have an impact on the production output and spatial requirements for the plant. It is also generally considered positive to collocate production facilities in proximity to downstream activities and the relevant supporting infrastructure.

3. Market assessment and production transition

As identified in the Task 1 report, a number of key bodies and working groups have published hydrogen road maps to guide the development of hydrogen as an alternative energy source. To contextualise Queensland's transition into hydrogen production and growth thereof, a high-level review of existing market forecasts and production options has been undertaken. This is based on publicly accessible sources, in the following section of the report. This includes advice surrounding the likelihood of transition from brown and blue to green hydrogen.

3.1 Market assessment

It is essential that Australia investigates the feasibility of exporting hydrogen, as it could potentially provide an option for the export of low to zero emissions energy on a large-scale and subsequently, alleviate pressure placed on the environment through the reduction of emissions. There are a number of factors that validate hydrogen as an attractive solution, including that it:

- Can be stored at a relatively low cost, depending on the form in which it is stored
- Is not dependent on any single type of energy generation or extraction method
- Can be exported to a wide range of locations.

Furthermore, hydrogen has a variety of applications including electricity and transport related uses, which makes it a highly versatile resource. This versatility in terms of applications and uptake decreases the potential for waste in that supply and demand are more likely to align[2].

According to the Hydrogen Council, as of 2017, global hydrogen production remained relatively stable at around 55 million tonnes per year. However, typical production methods for these exports were not low emissions procedures[3]. Current trends indicate that non-energy applications of hydrogen account for most of the hydrogen consumption. The production of ammonia accounts for approximately half of all demand for hydrogen while energy-related applications account for just approximately 1-2% of consumption[2].

Key inhibitors to building demand for hydrogen energy applications include the fact that it is not currently cost competitive with other sources of energy, such as fossil fuels. However, the technology required to minimise this gap is maturing rapidly, and the cost gap has narrowed in recent years and is likely to continue this trajectory into the foreseeable future[4]. According to CSIRO's National Hydrogen Roadmap, if hydrogen can be offered at a cost of less than $2/kg ($16.67/GJ), it could viably provide a cost-competitive option to replace natural gas turbines for dispatchable generation. Higher prices could be tolerable when non-financial factors such as supply security and environmental impacts are considered[5]. Other common issues have included technological readiness, market penetration lead times and infrastructure requirements.

Generally, interest in hydrogen is growing at a steady pace because of various contextual changes such as a global shift towards prioritising decarbonisation strategies through mechanisms such as the Paris Agreement. Locally, Australia has determined at all levels of government that establishing itself as a prominent supplier of hydrogen presents a lucrative opportunity for the economic growth of regional Australia[6]. This is aided further by disruptions to

[2] Acil Allen, Opportunities for Australia from Hydrogen Exports, 2018
[3] Hydrogen – Scaling Up, Hydrogen Council, November 2017
[4] CSIRO, National Hydrogen Roadmap, 2018
[5] CSIRO, National Hydrogen Roadmap, 2018
[6] Deloitte, Australian Global Hydrogen Demand Growth Scenario Analysis, 2019

the traditional energy supply chain, which includes the oil, gas, and electricity sectors. These disruptions typically take the form of more innovative production methods, supply mechanisms, and transportation, storage, and consumption methods[7]. An example of such an innovation is the integration of hydrogen into the energy supply chain. Although the aforementioned points present an encouraging outlook, there is still a level of uncertainty in regard to the growth trajectory, magnitude and timing of the hydrogen industry's development and therefore, this ought to be explored.

This section provides an overview of various demand and production scenarios at selected points in the future both within Australia and globally. The years of interest are 2030, 2035, 2040, 2045, and 2050. This review also offers a view as to the relative validity of the sources, data and methodologies used to inform various demand scenario projections. The forecasted scenarios will be used to determine the potential size of the supply and demand markets, to better understand the development opportunities within Australia and the scale of capital investment required.

3.1.1 Australia's role in the renewable hydrogen supply market

If renewable hydrogen becomes a significant source of energy globally, it is probable that many countries will need to import it to meet their demand. Conversely, many countries will seek to export hydrogen to fulfil this demand, naturally leading to the advent of a global hydrogen market. Australia is well placed to respond to this market demand and establish itself as a major player in the global hydrogen market.

Australia's ability to occupy a share of the hydrogen market will be determined by various influences, which are likely to be similar to those factors that support Australia to be a supplier of the global market for other energy resources.

At a high level, establishing a hydrogen market is a two-step process. The first step is reducing the cost of production to be competitive with the alternatives, which all potential incumbents will attempt to do. The second step is leveraging non-price factors in order to become a long term stable supplier. This includes factors such as the provision of related infrastructure including ports and compression facilities and working with various stakeholders throughout the supply chain. Other factors influencing the establishment of the market are likely to include the carbon footprint of Australia's hydrogen exports, Australia's reputation as a reliable supplier of energy exports and Australia's political and economic situation, which is widely regarded as stable and predictable.

3.1.2 Overview of demand assessments reviewed

Making projections as to the likely future global hydrogen economy and the likely use of hydrogen for energy applications is difficult because it is still in the early stages of adoption, yielding a large degree of uncertainty. The Hydrogen Council have projected that the seven most prominent applications will include the enabling of large-scale renewable energy integration and power generation, distribution of energy, use as a buffer to increase energy system resilience, decarbonising transport and industrial energy use, helping to decarbonise heat and power and finally, providing a clean feedstock for industry[8].

GHD's study has uncovered a wide range of possible uptake projections with a large degree of variation in their outlooks, this is because:

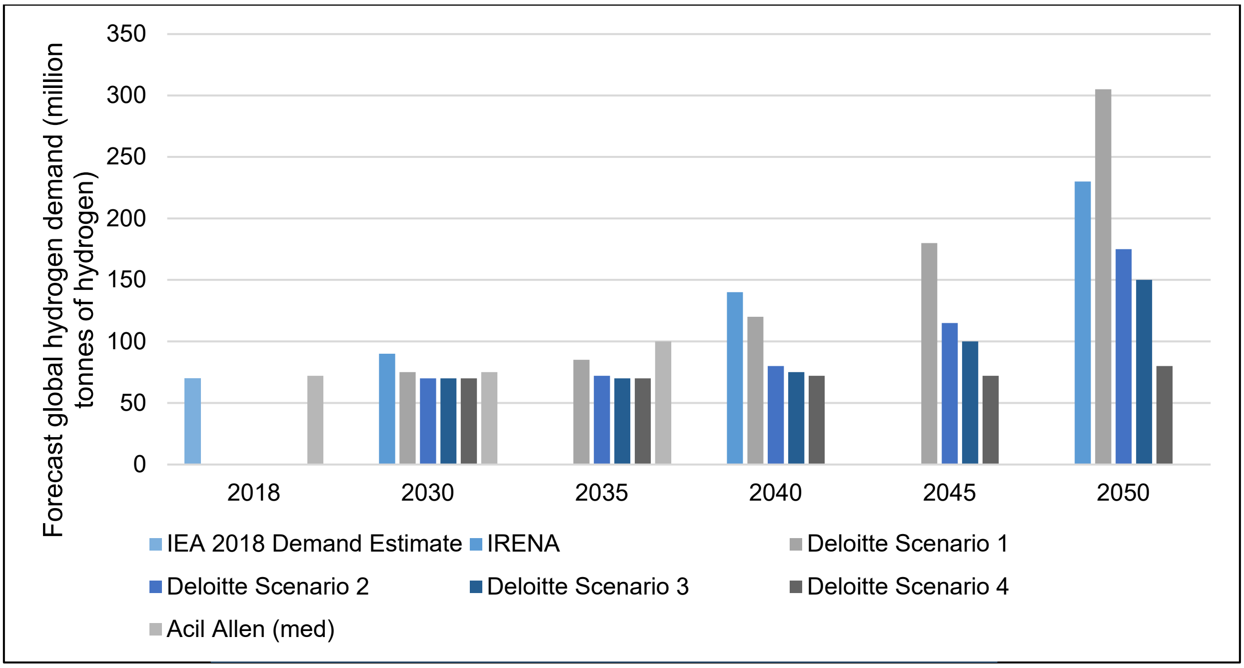
[7] Deloitte, Australian and Global Hydrogen Demand Growth Scenario Analysis, November 2019
[8] Hydrogen Council, Hydrogen – Scaling Up, 2017

- The factors behind the projections differed across sources. One of the most notable differences was the base case hydrogen volumes that were used. Currently, most demand stems from the non-energy sector.
- Time periods also varied. Despite this, the studies that were reviewed concluded that the sector will undergo a considerable expansion between the years 2030 and 2040.

The below figure shows the retrospective cumulative global demand for hydrogen in 2018 in its pure form before it is combined with any other substances, which is estimated by the IEA to have been approximately 70 million tonnes per annum (Mtpa). The most common applications of this commodity include refining and ammonia production. This was treated as the baseline for all additional demand.

Various publicly available forecasts foresee significantly different outcomes for demand levels. This is due to a large degree of uncertainty and different methods of demand forecast measurement that have been implemented whereby some sources used joules while others used tonnes.

Figure 3-1 Estimated Forecast Global Hydrogen Demand (million tonnes hydrogen)[9]



3.1.3 Literature review

We have conducted a comprehensive evaluation of relevant documents pertaining to the global outlook for the hydrogen industry, focusing on green hydrogen.

Hydrogen demand forecasts range considerably due to the unpredictable outlook in terms of market development and the methods of measurement that were adopted. Despite this, it is still clear that there is an acceptable level of industry and government support, which is a key enabler in increasing future hydrogen demand. Private investment will also largely determine the market characteristics. The literature review below generally aligns with the key pieces of literature that were reviewed in the Part 1 report.

[9] Various sources

Opportunities for Australia from Hydrogen Exports, Acil Allen

Acil Allen examined potential demand for hydrogen across a total of nine markets: China, Japan, Korea, Singapore, Taiwan, Thailand, India, California, and the European Union. From these, four key markets were selected: Japan, Korea, Singapore and China. Demand from the rest of the world was also considered. The demand projections were shaped by a variety of factors including population, energy market, current hydrogen-related activity, government policies, and research and development expenditure related to hydrogen. Three scenarios were developed for 2025, 2030 and 2040. The baseline scenario was broadly consistent with the New Policies Scenario in IEA's 2017 World Energy Outlook. Three hydrogen demand scenarios were developed relevant to the baseline scenario and are based on various assumptions regarding uptake, political issues, and the price of alternative fuel in sectors where hydrogen may not enter the market[10].

Hydrogen Scaling Up, Hydrogen Council

This report sets out a possible direction for hydrogen in the long term, supported by a roadmap for its deployment. This report represents a more ambitious outlook for the deployment of hydrogen and assumes an aggressive approach to scaling new technologies across value chains and sectors. It is reasonable to believe this would entail a large degree of coordination and dialogue between investors, policy makers and industry[11].

National Hydrogen Roadmap, CSIRO

The preparation of this report was supported by input from industry, government, and consulting participants. Its purpose is to set out a path for the development of a green hydrogen industry in Australia. The Roadmap sets out “base case” cost figures, which suggests an optimistic future for the hydrogen industry. As the aim of this report is to inform and support industry, it aims to inform the next stage of investment across various stakeholder groups including industry, government, and research[12].

Strategy for Energy Transition, Shell

This report investigates the potential for hydrogen to be used for final energy consumption as a high-density and storage energy source in transport and industry. It is primarily focused on hydrogen and the facilities that will be required to refuel vehicles. The key aim of this report was to enable Shell to develop its strategy and includes consideration for green hydrogen relating predominately to the transportation industry[13].

Hydrogen from Renewable Power, IRENA

This report was prepared to investigate the transition towards more sustainable energy sources that is occurring across the global energy system as a result of the targets set out by the Paris Agreement. The report outlines that although there are difficulties associated with converting some areas to electricity, such as transport or any industry requiring high-grade heat, hydrogen could provide a feasible solution for their conversion. Insights provided by this report are mostly related to the role of hydrogen produced using renewable electricity[14].

The Future of Hydrogen, IEA

This report was collated at the request of the government of Japan during its G20 presidency. The purpose of the document is to analyse the current situation of the hydrogen industry and provide guidance as to the way forward. The information on which this study is based is reliable,

[10] Acil Allen, Opportunities for Australia from Hydrogen Exports, 2018
[11] Hydrogen – Scaling Up, Hydrogen Council, November 2017
[12] CSIRO, National Hydrogen Roadmap, 2018
[13] Shell Energy, The Energy Transition Report, 2018
[14] IRENA, Hydrogen from Renewable Power, 2018

recent and covers the current trends globally, the various relevant targets, policies and incentives that are under consideration. It does not make any projections as to what future demand may look like or provide options for meeting that demand[15].

Australian and Global Hydrogen Demand Growth Scenario Analysis, Deloitte

Prepared for the National Hydrogen Strategy Taskforce to aid in their development of the National Hydrogen Strategy, the key purpose of this report was to review and provide analysis of existing forecasts of international industry development, supply cost reductions and expected hydrogen prices in order to understand the expected growth in demand globally and the share of this that Australia could potentially capture. This was done through the undertaking of scenario modelling to understand potential Australian hydrogen exports and domestic demand growth to 2050 and the scope and distribution of economic and environmental costs and benefits from Australian hydrogen industry development[16].

Shell Hydrogen Study, Energy of the Future, Shell

This report investigates hydrogen and its chemical properties, possible supply pathways, storage and transportation options, environmental factors, refuelling station infrastructure, vehicle ownership costs, other mobility applications, and stationary energy applications. The purpose of this study is to give an overview of the technical state of and future prospects for hydrogen and fuel cell technology across all transport sectors, including non-road modes, although it is heavily road focussed. The associated costs and cost effectiveness of hydrogen for mobility are presented as an important decision-making criterion, as well as the importance of developing hydrogen supply infrastructure and its availability. Finally, since hydrogen powered vehicles are only viable if they can be operated more sustainably than today's vehicles, Shell used scenario techniques to estimate and assess possible energy and environmental balances for future fuel cell passenger car fleets[17].

Hydrogen: A Renewable Energy Perspective, IRENA

This report was prepared by the International Renewable Energy Agency for the 2nd Hydrogen Energy Ministerial Meeting. It was prepared in response to the G20 Karuizawa Innovation Action Plan on Energy Transition and Global Environment for Sustainable Growth, which called on IRENA to develop the analysis of potential pathways to a hydrogen-enabled clean energy future. The report is comprised of four components:

- Strategic considerations
- The hydrogen-renewable energy nexus
- Hydrogen economics
- Future hydrogen commodity trade in light of emerging applications[18].

[15] IEA, The Future of Hydrogen, 2019
[16] Deloitte, Australian and Global Hydrogen Demand Growth Scenario Analysis, November 2019
[17] Shell Energy, Shell Hydrogen Study, 2017
[18] IRENA, Hydrogen: A Renewable Energy Perspective, 2019

3.2 Market assessment findings

Table 1 provides a comparison of the sources examined in the literature review and their estimated demand forecasts for various scenarios for the years 2030, 2035, 2040, 2045 and 2050. It is important to note the large degree of variance in demand forecast as time progresses. The projections for hydrogen uptake in the year 2050 have a range of 460 million tonnes (Mt) per annum, which demonstrates that there is a large degree of ambiguity regarding the future outlook for hydrogen. The maximum forecast growth in demand between the years 2030 and 2050 was made by the Hydrogen Council and is 440 Mt. The minimum growth projection is Deloitte's Scenario 4, 'Electric Breakthrough', which foresees a rise in demand of just 10 Mt. Across all the scenarios investigated, the average growth for the period is 154 Mt.

Table 1 Estimated Forecasted Global Hydrogen Demand (million tonnes hydrogen)[19]

	2018	2030	2035	2040	2045	2050
EA 2018 Demand Estimate	70					
Shell		70	72	85	100	135
Acil Allen (med)		72	75	100	NA	NA
IRENA		90	NA	140	NA	230
Deloitte Scenario 1		75	85	120	180	305
Deloitte Scenario 2		70	72	80	115	175
Deloitte Scenario 3		70	70	75	100	150
Deloitte Scenario 4		70	70	72	72	80
Hydrogen Council		100	125	200	340	540
Average		77	81	109	151	230
Upper Limit (+25%)		96.4	101.6	136.3	188.9	288.4
Lower Limit (-25%)		57.8	60.9	81.7	113.4	173.0

3.2.1 Assessment of demand relevance

Given the variability in demand projections, criteria were applied to assess and rank the reliability and relevance of each projection. The criteria included the originality of the data, the assumptions made in the study, how recently it was published, the relevance of the contents to this study, and the geographic coverage of the study.

Each source was scored depending on its fulfilment of each piece of criteria, a score of 10 being the highest and 1 being the lowest. The scoring is linear on an equi-distance basis whereby the weighting gap between 3 and 4 is equal to the weighting gap between 8 and 9, and only integers are used. Criteria was selected based on its relevance to source reliability. Any sources with a cumulative score of below 30 were discounted as they were not deemed to be satisfactory. Based on the cumulative scores, each source was ranked from one onwards, a

[19] Various sources

ranking of one indicating the highest quality and most relevant source. A breakdown of the scores can be viewed in the table below.

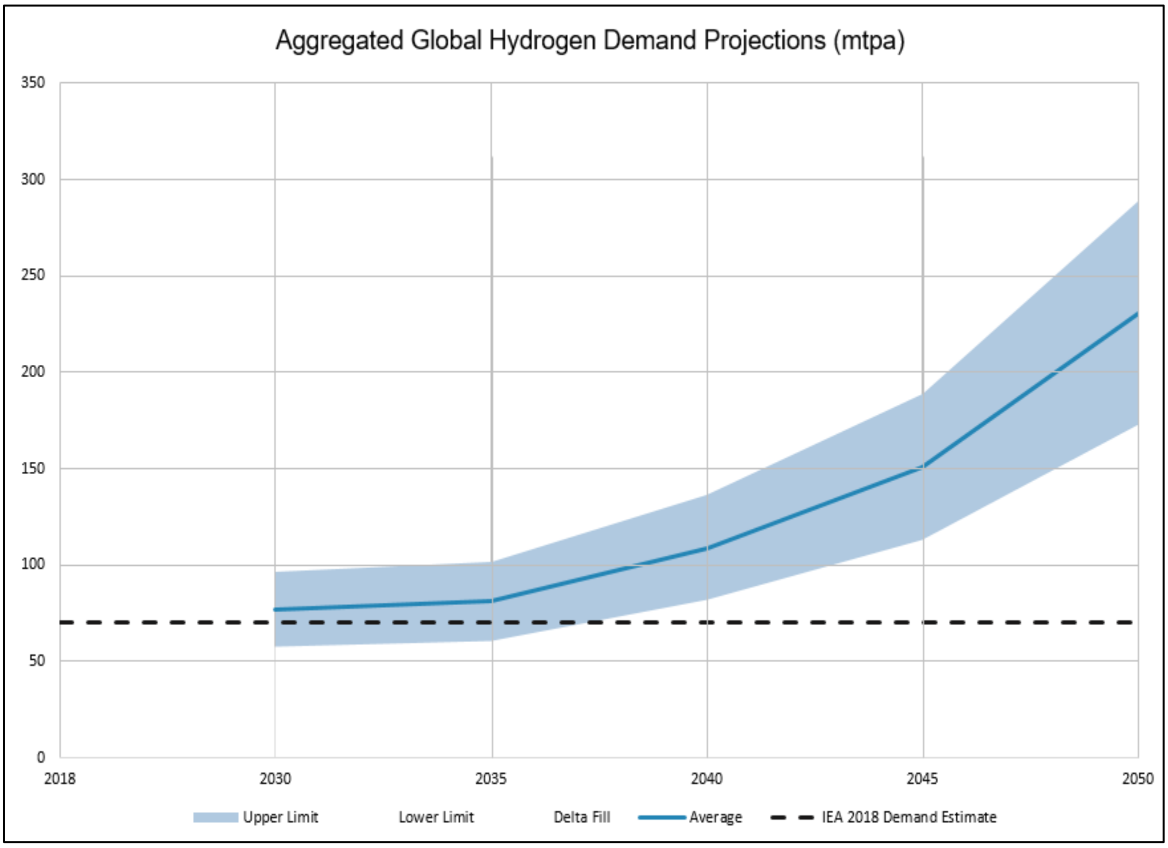
Demand projections from each of the sources that satisfied the requirements were blended to identify the average of all the projections. A buffer of +/- 25 percent was applied to yield a market guidance profile. These figures can be viewed below. It is important to note that these figures are conservative estimates drawn from publicly available visual representations. Additionally, the high uptake scenarios from Acil Allen were excluded as they largely align with projections made by the Hydrogen Council, which are extremely optimistic.

Table 2 Summary of relevant of hydrogen historical demand projections

Title	Opportunities for Australia from Hydrogen Exports	National Hydrogen Roadmap	Australia's National Hydrogen Strategy	Australian and Global Hydrogen Demand Growth Scenario Analysis	Hydrogen for Australia's Future	Hydrogen, Scaling Up	The Future of Hydrogen	Shell Hydrogen Study	Hydrogen: A Renewable Energy Perspective
Author	Acil Allen	CSIRO	COAG Energy Council	Deloitte	Hydrogen Strategy Group	Hydrogen Council	International Energy Agency	Shell	IRENA
Date	Aug-18	Aug-18	2019	Nov-19	Aug-18	Nov-17	Jun-19	2017	Sept-19
Criteria					**Score**				
Recency	7	7	10	10	7	6	9	6	10
Data Source	8	6	0	9	5	7	7	8	8
Assumptions	Presumed high uptake of hydrogen is based on assumptions relating to climate change, technology adoption, alternative fuel prices and efforts to achieve outcomes desired in the Paris Climate Accord.	Extremely high uptake of hydrogen driven by developments in the production, storage and transport technologies, environmental pressures and pricing sensitivities.	Uptake will be heavily dependent on various pricing factors such as price of transport, price of production and price of storage.	Assumes countries are gearing themselves up already to adopt hydrogen technology	High uptake of hydrogen driven by the wide range of applications and lack of emissions when it is produced using green technologies.	Assumes aggressive and coordinated approach by industry, investors and government. Figures represent the upper limit.	Assumes moderate hydrogen uptake and assumes prices, demand levels and other parameters according to other IEA studies.	Assumes feasibility of electrolysis, high uptake of Fuel Cell Electric Vehicles (FCEV's) and various cost factors.	Assumes that costs fall enough in the future to make green hydrogen economically feasible.
Relevance	9	5	5	9	7	6	6	9	9
Geographic coverage	9	5	5	9	5	5	5	9	9
Total	33	23	20	37	24	24	27	32	36
Ranking	3	7	8	1	6	6	5	4	2

Figure 3-2 below shows the projected range and average demand based on the aggregated global demand figures outlined in Table 1 out to the year 2050. The range is +/-25% of the average. Over time, hydrogen demand is projected to increase steadily. Initial aggregate demand is expected to be between approximately 60 million tonnes per annum and 95 Mtpa in 2030, and raising to between approximately 175 Mtpa and 280 Mtpa by 2050.

Figure 3-2 Aggregated estimated global hydrogen demand projection



4. Hydrogen plant requirements

The following section of the report details the spatial criteria necessary for the establishment of a hydrogen plant. This includes the plant configurations, typical spatial requirements, utility service requirements, transportation requirements, colocation opportunities and safety and security.

To inform a high-level review of hydrogen plant requirements, the production scenarios in Table 3 have been adopted. The production scenarios are based on the amount of hydrogen produced in three different sized commercial ammonia plants. The size 3 plant is approximately 50% of the size of a very large ammonia plant, which is approximately 8 times larger than what is currently considered a very large hydrogen liquefaction plant.

Table 3 Production scenarios of hydrogen and derivative type

Production scale			
Product	**Size 1**	**Size 2**	**Size 3**
Hydrogen			
Hydrogen production (tpa)	8,687	34,748	86,870
Ammonia production			
Ammonia (tpa)	46,504	186,017	465,043
density (t/m3)	0.73	0.73	0.73
Ammonia (m3/a)	63,704	254,818	637,045
MCH (organic carrier) production			
MCH (tpa)	138,992	555,968	1,389,920
density (t/m3)	0.77	0.77	0.77
MCH (m3/a)	180,509	722,036	1,805,091
LH2 production			
LH2 (tpa)	8,513	34,053	85,133
density (t/m3)	0.07	0.07	0.07
LH2 (m3/a)	121,614	486,471	1,216,186

4.1 Plant configurations and general location considerations

4.1.1 Plant configurations

Plant configuration has implications to the footprint and logistics, which strongly influence locational requirements. The key process plant blocks are:

- Water treatment – water treatment is generally located at the hydrogen production plant, but part of the water treatment plant may be located separately, for example if it involves desalination. Treated water can be transported long distances in underground pipelines.
- Hydrogen production – hydrogen plants are a large power consumer and may be best located close to a robust power grid connection point. Gaseous hydrogen can be transported long distances in underground pipelines.
- Plant to convert hydrogen to liquid hydrogen (LH2), anhydrous ammonia or methylcyclohexane (MCH) – heavy industrial plants with hazardous products. Ammonia and MCH can be transported long distances in underground pipelines. However, LH2

pipelines have limited transport range, and longer distance would require cryogenic vehicle transport.

- Product storage for shipping and ship loading – generally close to the port due to high capacity ship loading rates and distance limitations on low temperature ammonia or cryogenic hydrogen pipelines.

The plant configurations are shown in Figure 4-1. The top configuration shows all plants may be separately located to suit their requirements. For example, a desalination water treatment plant may be located at the coast, a hydrogen production plant could be located near a high voltage substation, the hydrogen conversion plant could be located in an industrial precinct and the product storage could be at the port.

The middle option shows the water treatment plant located at the hydrogen production site, which would be supplied with power and water. Gaseous hydrogen would be piped to a conversion plant at the port which would also contain the shipping storage and be close to the ship loading facilities.

The bottom option shows an integrated plant with all process blocks at or near the port. This requires a large power supply and water supply to be available near the port.

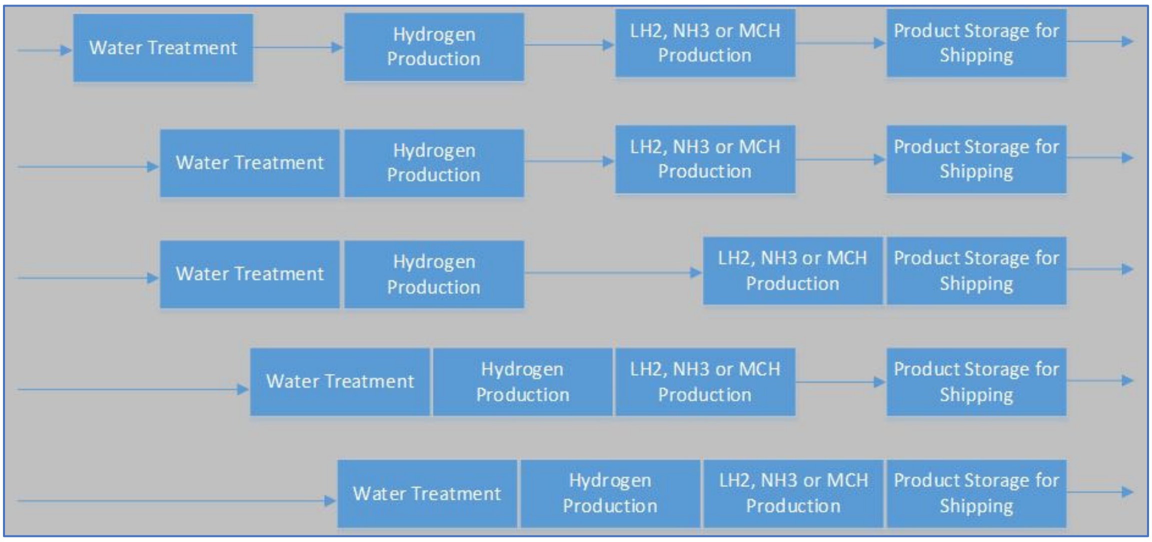


Figure 4-1 Plant configuration options

The preferred scenario from a planning and logistics point of view would be to develop an integrated plant at or nearby a port. Overall, an integrated plant would be more efficient in that production and processing components are collated. Key advantages and disadvantages of constructing and operating an integrated plant are discussed in Table 4 below.

Table 4 Key advantages and disadvantages of constructing and operating an integrated plant

Integrated plant	
Advantages	**Disadvantages**
• A single site would allow for the most optimal plant location and efficient use of the land. A key requirement of industrial uses that have likely impacts on the environment (for example: major hazard facilities) have legislated requirements, for instance site layout and separation distances. An integrated plant imposes those requirements over a single site, resolving the need for duplication on multiple sites. • Concentrates approval requirements, operational processes including the installation and operation of security features, and overall management. • Separate sites require additional equipment (e.g. utilities) and buffer storage for the transfer mode between sites (pipeline, road or rail). These can be eliminated or significantly reduced in an integrated plant. • The resource is required to be transitioned from the production to processing stages. Undertaking these stages on a single site means that no pipeline or other transport options are required between multiple sites.	• Where an integrated plant is not proximal to a port, duplicate storage facilities at the port would be required. Therefore, there will be duplication of storage facilities to some extent. • The larger footprint requirements suggest it would be more difficult to locate an integrated plant at or very near the port due to the limited supply of premium land, which is also often reserved for port related uses. • An integrated plant would require a larger parcel of this premium land. • An integrated plant requires the convergence of multiple site requirements such as high voltage power and water availability, sufficient land area for plant footprint and buffers and port connectivity. Sites that can be located close to desirable infrastructure may be difficult to locate.

While an integrated plant would offer the above advantages, there are alternative configurations that potentially provide greater siting flexibility that should also be considered:

- A separate hydrogen plant with pipeline/transport to a separate processing plant at or close to the port where processing, cryogenic/refrigeration and storage facility are available.
- A separate hydrogen plant with pipeline/transport to a separate processing plant some distance from the port, and a pipeline/transport for the processed product to duplicate cryogenic/refrigeration and storage facilities at the port.

4.1.2 General location considerations

The location of an integrated hydrogen production and carrier processing plant at a port would have the following advantages:

- Seamless integration with the storage and loading facilities required at the port
- Negates requirement of pipelines within pipeline corridors to transport the resource from another location

- No likely impact on the local transport network.

Should a port location not be feasible due to land availability or potential for land use conflicts with other port activities (such as tank farms), the development should be nearby to the port, the distance from the port being largely determined by the transport requirements of the final downstream product (LH2, ammonia, or enriched organic carrier [MCH]). This is discussed further in Section 4.4.2.

Electricity

A significant requirement of the hydrogen production plant, particularly the electrolysis units, will be the proximity to a major power source, as large electricity inputs are required to produce green hydrogen (GH2). For large volume plants, accessibility to a major power source is likely to be the major location determinant.

Pipeline

The electrolysis plant could be located at a source some distance from the carrier processing plant, as it is technically feasible to pipe GH2 over long distances without specialist infrastructure or restrictive above ground pipeline corridors. While shorter piping distances would reduce the capital costs and corridor requirements, it is considered that distances greater than 50 km not relevant to the focus of this report on the Townsville and Gladstone planning areas.

For a small plant the GH2 could be trucked to the processing plant. The volume of product that can be transported by road would depend on transport distances and capacity of the road/ endpoint infrastructure. As a guide, truck transport for small plants generating up to 10,000 tpa may be most practicable.

The carrier processing plant should be either at, or close to, the port as specialised above ground insulated pipelines are required to transport LH2 or ammonia. LH2 pipelines should be as short as possible, and less than 1 km due to the complexity and size of the pipeline required to convey the LH2 at extreme low temperatures, particularly those required for ship loading over limited timeframes. Low temperature ammonia pipelines are also highly specialised but the technology is more proven and pipeline distances of up to 5 km are considered practicable.

The use of toluene as an organic carrier would require a product pipe taking H2 enriched organic carrier to the port and a return pipe bringing spent organic carrier back to the enrichment plant. Use of an organic carrier would also require additional storage facilities at the port and enrichment plant (for enriched and spent toluene). While a specialised pipeline is not required, the need for additional piping and storage requirements suggests a location as close to the port to limit pipe length and potentially obviate the need for separate transport storage facilities would be most cost effective.

As noted, processing plants should be as close to storage and loading facilities as piping of LH2 and ammonia over long distances becomes problematic and to avoid need for duplicated facilities at port and to enable control of loading operations.

Water

Access to a reliable water supply is an essential feedstock requirement for the production of hydrogen by electrolysis. Water may also be used in cooling towers for process cooling in the hydrogen production and hydrogen conversion processes. Some of the process cooling can also be done using air, although air cooling typically is more expensive, uses more power, requires more land and can have limitations at high ambient temperatures. If all the process cooling is done with cooling towers, the water demand could be three to four times higher than the amount required for electrolysis. If the system is air predominantly air cooled the water consumption could be as little as 1.5 times the amount required for electrolysis.

A size 3 hydrogen and ammonia plant with all cooling done by water will require around 3,400 ML/y (refer section 4.3.2). The water volumes are relatively manageable and associated infrastructure easily provided, even for the size 3 plant with all water cooling.

The quality of source water will influence both the quantity and quality of brine or wastewater generated which, in turn will influence the most appropriate disposal options. In the Gladstone and Townsville context, input water quality is expected to be quite high and therefore the wastewater from the electrolysis process would potentially be suitable for onsite land disposal. Additional site requirements will need to be allowed for water treatment and wastewater disposal facilities. These would be dependent on local conditions for disposal, and subject to environmental approval.

Opportunities are relatively limited for synergistic uses in proximity to the hydrogen plants due to relatively low amounts of heat or other by product or wastes produced. While oxygen is a potentially useful byproduct and is transportable, there are limited market opportunities. However, it can discharged to the atmosphere without environmental impacts.

4.2 Typical spatial requirements

The typical spatial requirements of a H2 production plant and downstream technology components are another key component to considering a plant's location. The requirements are a function of production components, storage, tanks and/or overall site arrangements necessary to operate a viable plant.

The tables below identify the spatial requirements for H2 production plant and downstream technology components. For the purposes of co-locating, the combined spatial requirements of H2 and the downstream technology(ies) should be considered (example: H2 production plus ammonia). These can greatly increase the spatial requirements to support the development, which further impacts other infrastructure requirements.

Table 5 Spatial requirements, H2 production

Parameter	Measurement	Size 1 8,687 tpa	Size 2 34,748 tpa	Size 3 86,870 tpa
H2 production				
Site *(land area + optional storage)*	m^2	5,727	22,421	53,638
Land area	m^2	4,375	18,375	45,938
Storage (waste water brine based on 30 day retention)	m^2	1,352	4,046	7,700
Tank arrangement	-	2 tanks (13m dia)	4 tanks (17m dia)	6 tanks (20m dia)
Tank footprint	m^2	265	908	1885

Table 6 Spatial requirements, ammonia production

Parameter	Measurement	Size 1 46,504 tpa	Size 2 180,017 tpa	Size 3 465,043 tpa
Ammonia production				
Site *(land area + storage)*	m^2	14,418	54,329	111,480
Land area	m^2	9,160	36,640	91,599
Storage area (product)	m^2	5,258	17,689	19,881
Tank arrangement	-	1 tank[20] (42m dia)	1 tank (42m dia)	4 spheres (24m dia)
Tank footprint (included in Storage area)	m^2	226	1,521	1,809

Table 7 Spatial requirements, H2 liquefaction

Parameter	Measurement	Size 1 8,513 tpa	Size 2 34,053 tpa	Size 3 85,133 tpa
H2 liquefaction				
Site *(land area + storage)*	m^2	6,959	36,473	61,373
Land area	m^2	4,150	16,600	41,500
Storage area (product)	m^2	2,809	19,873	19,873
Tank arrangement	-	1 sphere (15m dia)	6 spheres (24m dia)	6 spheres (24m dia)
Tank footprint	m^2	177	2,715	2,715

[20] For most tank arrangements, a separation of one tank diameter is assumed between tanks. Added to that is a standard requirement for separation of tanks from a fence line, road or equipment.

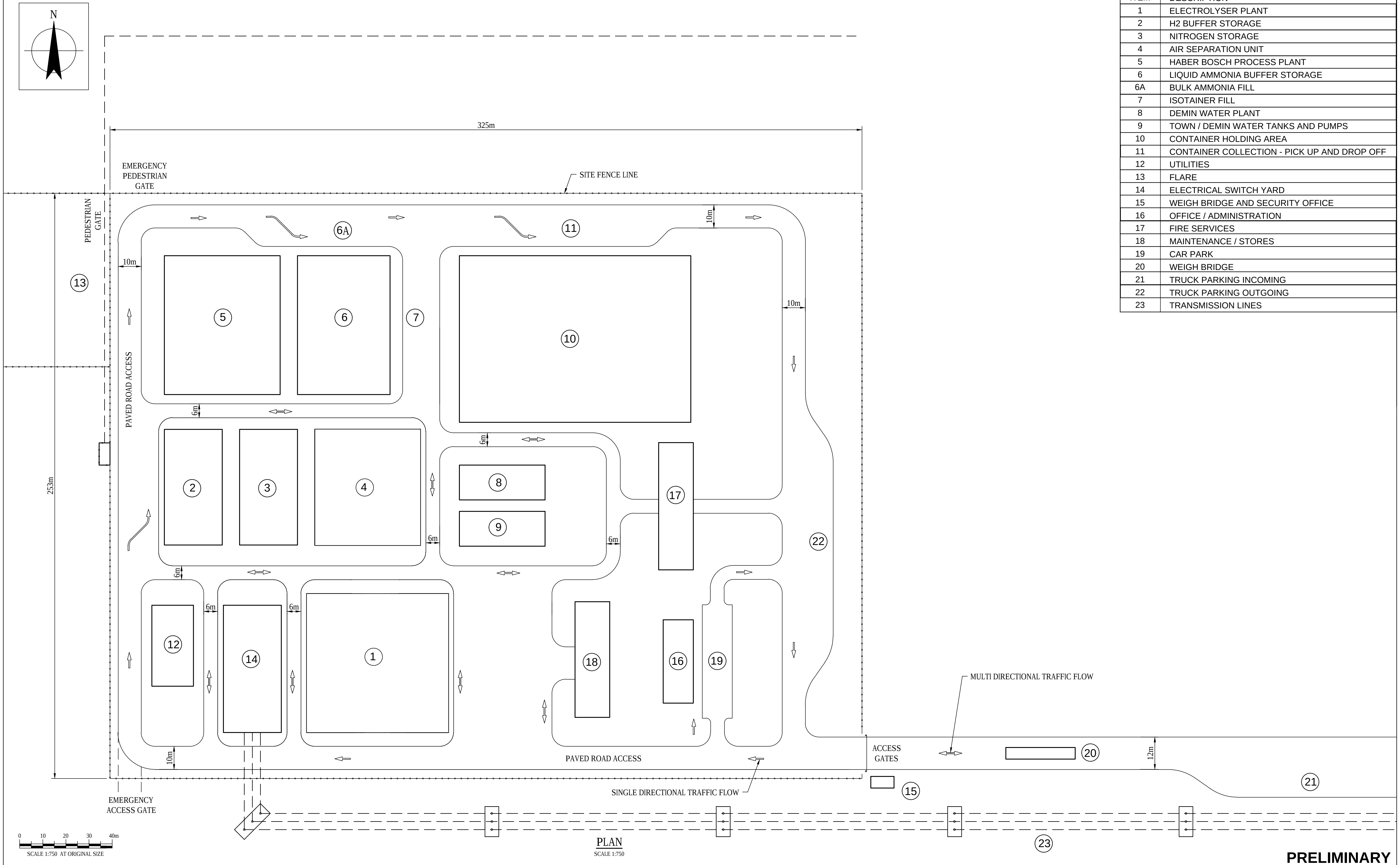
Table 8 Spatial requirements, MCH (organic carrier) conversion

Parameter	Measurement	Size 1 139,050 tpa	Size 2 556,200 tpa	Size 3 1,390,499 tpa
MCH (organic carrier) conversion				
Site *(land area + storage)*	m^2	26,415	84,020	207,549
Land area	m^2	9,855	39,500	100,000
Storage (product)	m^2	16,560	44,520	107,549
Tank arrangement	-	4 spheres (20m dia)	4 spheres (20m dia)	8 spheres (24m dia)
Tank footprint	m^2	1,257	1,257	5,620

4.2.1 Schematic plant layout

A high-level schematic layout of an integrated hydrogen to ammonia plant has been developed, as shown in Figure 4-2, based on the requirements outlined above. This schematic provides a general arrangement of the individual components that would be required onsite. Components are not considered to be to scale, rather a general representation of the sub-systems involved on an integrated site.

Both domestic and export market for ammonia is considered in the plant layout; iso-tainers (and iso-tainer filling) is considered for domestic ammonia distribution and bulk ammonia storage for ammonia export by ship.



ITEM	DESCRIPTION
1	ELECTROLYSER PLANT
2	H2 BUFFER STORAGE
3	NITROGEN STORAGE
4	AIR SEPARATION UNIT
5	HABER BOSCH PROCESS PLANT
6	LIQUID AMMONIA BUFFER STORAGE
6A	BULK AMMONIA FILL
7	ISOTAINER FILL
8	DEMIN WATER PLANT
9	TOWN / DEMIN WATER TANKS AND PUMPS
10	CONTAINER HOLDING AREA
11	CONTAINER COLLECTION - PICK UP AND DROP OFF
12	UTILITIES
13	FLARE
14	ELECTRICAL SWITCH YARD
15	WEIGH BRIDGE AND SECURITY OFFICE
16	OFFICE / ADMINISTRATION
17	FIRE SERVICES
18	MAINTENANCE / STORES
19	CAR PARK
20	WEIGH BRIDGE
21	TRUCK PARKING INCOMING
22	TRUCK PARKING OUTGOING
23	TRANSMISSION LINES

PRELIMINARY

No	Revision	Note: * indicates signatures on original issue of drawing or last revision of drawing	Drawn	Job Manager	Project Director	Date

Figure 4-2 Schematic plant layout

H2 to NH3

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E bnemail@ghd.com W www.ghd.com

DO NOT SCALE

Drawn	Designer
Drafting Check	Design Check
Approved (Project Director)	
Date	
Scale 1:750	This Drawing must not be used for Construction unless signed as Approved

Client

Project

Title

Original Size A1 Drawing No: Rev:

4.3 Utility service requirements

4.3.1 Electricity

The electrolysis process for hydrogen production is very energy intensive and requires a large amount of electricity. The typical power requirements for the various plant components for the adopted plant sizes (1, 2 and 3) are identified in Table 9 below.

Table 9 Typical power requirements for plant components

Parameter	Measurement	Size 1	Size 2	Size 3
H2 production				
Power demand (electrolysers)	MW	77	308	770
Ammonia production				
Power demand	MW	6	23	59
H2 liquefaction				
Power demand	MW	7	29	73
MCH (organic carrier) conversion				
Power demand	MW	2	6	16

Given the power requirement for the electrolysers, a high voltage line is required to connect the hydrogen production site to the electricity grid. The supply voltage (66, 132 or 275 kV) is determined by the amount of power required and the distance to a suitable grid connection point.

Renewable energy can be delivered via the electricity grid from any renewable energy generator also connected to the grid. However, nearby generators are preferred to minimise inherent grid power losses. An overview of the typical technical and economic maximum distances for a certain transmission voltage and electrical load (demand) for the adopted plant sizes (1, 2 and 3) is provided in Table 10.

Table 10 Power supply requirements H2

Power Supply	Measurement	Size 1	Size 2	Size 3
Power demand Electrolyser plant	**MW**	**77**	**308**	**770**
Power line distance limit @ 33kV	Km	Not Suitable	Not Suitable	Not Suitable
Power line distance limit @ 66kV	Km	80	Not Suitable	Not Suitable
Power line distance limit @ 132kV	Km	200	50	20
Power line distance limit @ 275kV	Km	>500	300	125

As detailed in Table 10, a Size 1 plant (77 MW) could be fed from a 66 kV line up to a distance of 80 km. A Size 3 plant would require to be fed from a 132 kV to 275 kV source with maximum draw distances 20 and 80 km respectively. However, the cost and approvals complexity of extending high voltage transmission lines suggest plants requiring high power loads should ideally be located as close as possible to transmission line or substation. For this reason, the location of a major energy source or existing HV network will effectively determine the location of electrolysis plant. An electrolysis plant would have locational advantage being closer to a transmission line or substation in that:

- Less costly infrastructure would be required to connect to the national grid
- There would be lower power losses due to lower transmission distances

Consideration should be made to the higher cost of land in proximity to transmission lines or substations, which may offset some of the abovementioned advantages.

Land required for large renewable power generation may not be available in proximity to the proposed hydrogen plant and, therefore, renewable generators maybe located remote to the site and to feed into the existing transmission network. This will incur network charges for the electricity and may precipitate an augmentation of the network.

4.3.2 Water

Hydrogen production requires a sustainable water supply that may be provided to plant via utility pipelines. The utility water supply is not pure enough for use in the electrolysis units, which require clean demineralised water as feed. The electrolysis units are usually packaged with reverse osmosis (RO) and electro deionisation units to demineralise the water. To be treated through these units without causing fouling or scaling, the water must meet certain specifications (e.g. low turbidity, suspended solids, and maximum conductivity). If the water is not of good enough quality to feed directly into the RO unit, it must undergo pre-treatment to remove suspended solids and turbidity for example. This is done through media or membrane filtration steps.

Utility water may also be used for process cooling in cooling towers.

The typical water requirements for the various plant components for the adopted plant sizes are discussed in Table 11.

Table 11 Typical water requirements for water cooled plant components.

Parameter	Measurement	Size 1	Size 2	Size 3
H2 production				
Water consumption (electrolysers only)	ML/a	104	417	1042
Total raw water consumption (electrolyser + brine) - demineralisation plant	ML/a	136	542	1355
Cooling Water	ML/a	203	813	2030
Total	**ML/a**	**443**	**1772**	**4427**
Ammonia production				
Process and Cooling Water	ML/a	298	1191	2976
Raw water pipeline for hydrogen and ammonia				
Indicative diameter based on normal pipeline velocities	NB mm	100	200	300

Hydrogen liquefaction and MCH production is expected to require similar or less water than ammonia production.

Generally, the water pipeline carries a smaller cost than many of the other components and should not be a main driver in the decision as to where to locate the plant. While it is important that a sustainable water source can be found, if a sustainable water source is not available, an alternative source such as seawater (if the plant is located in proximity to the ocean) or treated effluent would be needed. Disposal or alternative use options for wastewater/brine would need to be addressed during the pre-feasibility, feasibility and approval stages for a project.

4.3.3 Wastewater/brine treatment

Townsville has the ability to provide treated effluent via a recently connected effluent diversion main between the two main sewage treatment plants (STPs). Consideration of the additional treatment and disposal options of the by-product would need to be considered if these options were to be adopted. Gladstone Regional Council did not provide advice on the local government's wastewater/brine treatment capabilities. Further discussions with Townsville City Council and Gladstone Regional Council would be required for the consideration of appropriate treatment and disposal options.

Wastewater from the plant is comprised of reject streams from for example, desalination (where sea water is utilised), RO and water polishing (EDI or IX) for electrolyser use, as well as cooling water blowdowns, boiler feed water blowdowns, used wash water and potable water rundown. The brine is the effluent from the water treatment and demineralisation process which is required to produce water suitable for hydrogen production.

Cooling tower blowdown is a waste stream from the cooling water circuit that is required to bleed off salts that accumulate when recirculating water evaporates in the cooling tower.

Wastewater should be minimised as this is associated with a high disposal cost. Blowdown can be minimised by utilising air cooling thereby reducing the amount of water cooling required and/or increasing the number of cycles for cooling water recirculation. Wastewater may be discharged to the ocean (dependent on proximity), or otherwise disposed off-site. Alternatively, reject water from the water treatment may be recycled e.g. raw water/fire water storage with some bleed to maintain quality, thereby minimising the brine/waste water.

An evaporator/crystallyser unit may be utilised (or other evaporation treatment measures) but these could be expensive due to exotic materials of construction required and energy-intensive (to forcibly remove water from the brine). In addition, the mixed salt product that is produced still must be disposed and has no economic value.

Consultation with Townsville City Council has identified that disposal into the Council wastewater system would be accepted. There is the potential to add wastewater to the existing recycle water network but would be on a case by case basis. The addition of wastewater to the recycled water network has the advantage of future beneficial use for community (e.g. green spaces), commerce (agriculture), heavy industry or mineral processing plants. As mentioned previously disposal into the ocean way be viable but will be dependent on site location and government approval.

If the addition to the recycled water network option was adopted, the following would be required:

- Ability to store the wastewater on site for 30 days
- Transfer of stored water via pipeline connecting to the existing recycled water networks at a location where the network pipeline is approximately three times the size of the of the brine pipeline.

If disposal to sea was the option that was adopted, the following would be required:

- Ability to store the wastewater on site for five days, due to small storage time no additional land will be required.
- Transfer of stored water via pipeline connecting to a suitable ocean outfall. The location requirements for the ocean outfall and the discharge approvals process are uncertain and may prove unviable.

In the Gladstone and Townsville context, high quality input water is expected. This means that the wastewater from the on-site water treatment plant may potentially be suitable for onsite reuse or land disposal. Table 12 provides an estimated calculation for a wastewater discharge amount of 350 ML/a for Gladstone and Townsville respectively; 350 ML/a has been adopted as it generally aligns with the proposed disposal amount that would be required for an air-cooled Size 3 hydrogen plant.

Table 12 On site disposal requirements (wastewater)

Parameter	Measurements	Gladstone	Townsville
Annual water disposal	Ml	350	350
Evaporation			
Evaporation rate	mm/yr/m^2	1,692	2,520
Annual rainfall	mm/yr/m^2	880	1143
Net evaporation	mm/yr/m^2	812	1377
	mm/day/m^2	2.2	3.8
Area required	ha	43.1	25.4
Land application			
Average Recycle rate	mm/day/m^2	3	3
Area required	ha	32.0	32.0

Given the options available for the treatment of onsite wastewater, the wastewater requirements would vary. The disposal to site (evaporation and land application) area requirements are significant, and therefore it may be suitable to adopt an approach that uses a combination of disposal methods. Should treated effluent from local STPs be used, concentrations for discharge onto land would need to be closely considered to land suitability.

4.3.4 Other

There will be a need for information and communications technology (ICT) for plant operations and security. An ideal location would already be serviced by telecommunications or have the ability to readily connect to an available network.

4.3.5 Co-location opportunities

There may be an opportunity to co-locate a plant nearby to an existing power station. Power stations area already adequately serviced with utilities, and complementary ancillary infrastructure including access to raw water, wastewater disposal sites and high-voltage switch yards.

4.4 Transport requirements

4.4.1 Transport of hydrogen

From a technical perspective, hydrogen is not a difficult resource to transport in that it may travel via pipeline, road tanker, rail carriages or ships. The type of transport suitable for the hydrogen is highly dependent on volumes, and any options analysis should also take into consideration cost and risk. Low volumes of hydrogen would benefit from road tanker as the number of trucks per annum can be controlled based on output and there are no large infrastructure expenses. In contrast, high volumes of hydrogen would benefit from construction of a pipeline which will have a larger upfront expense, however, relatively lower running costs over time, and less interface with the community. Temporary use of road transport methods may also be considered for initial production. If this occurs, a common depot may be a suitable solution to provide a common storage point and feed point into any domestic or export distribution.

4.4.2 Transport of carrier product

Depending on the volume of carrier product, the most appropriate transportation method to storage facilities and/or export locations varies. The option of road transport may be a practical solution to the transport of smaller volumes of product over longer distances although truck movements would be limited by the capacity and suitability of the transport network (traffic volumes, hazardous material routes, etc.) and capacity of the end point facilities. Alternately, the option of a pipeline may be a more practical option to the transport of larger volumes of product over longer distances. Table 13 shows the number of truck movements per annum required for the transport of GH2, LH2 and carrier product from the different plant capacity sizes. Single trailer loads have been assumed for Size 1 plant and double trailers for Size 2 and 3 plants. The table indicates that road transport may not BE considered practicable for any of the larger scale plants.

Table 13 Trucks dispatched

Parameter	Measurement	Size 1	Size 2	Size 3
H2 Production				
Trucks dispatched	Per day	63	127	317
	Per annum	23,133	47,176	115,665
Ammonia production				
Trucks dispatched	Per day	6	12	30
	Per annum	2,212	4,424	11,060
H2 liquefaction				
Trucks dispatched	Per day	11	21	54
	Per annum	3,923	7.846	19,616
MCH (organic carrier) conversion				
Trucks dispatched	Per day	17	34	86
	Per annum	6,268	12,535	31,338

There are several issues associated with the transport of the carrier product which will influence the preferred transport option from plants. For reference, large Australian container ports have around five thousand truck visits per day. In isolation, these traffic volumes may not seem like a lot, however, they need to be viewed in context of the road capacity.

Ammonia

Chilled ammonia for loading onto ships must be transported in refrigerated tankers or, more likely, transmitted through an insulated above-ground pipeline. Given the cost of such a pipeline and the practical implications of having a large inventory of ammonia in a long pipeline, the pipeline should be as short as possible. The longest ammonia pipeline in Australia is approximately 5 km long. Other difficulties with long pipelines include getting approval for the pipeline, in particular in populated areas (e.g. close to a port), and considerations with regards to the boil-off gas (BOG) that is generated during loading of the ammonia and has to be returned to the plant. While technically, the ammonia pipeline can be as long as it needs to be, there are economic, safety and general practical considerations to keep it as short as possible.

It is more desirable to produce the ammonia close to port and then transmit it through a short pipeline to storage at port, although storage at site if the site is close enough to port could also be a solution. At least a shipload parcel has to be stored. It has been elected to store 150% of a shipload parcel, to allow for flexibility in shipping schedules, delays and other unforeseen circumstances.

A site with an inventory of more than 50 tonnes of ammonia results in the site being classified as a Major Hazard Facility. However, most shipping storage will vastly exceed this limit. The Yara Ammonia plant in Western Australia has two 30,000 tonne storage tanks.

LH2

Hydrogen is liquefied at very low temperatures (-253ºC). The materials of construction and energy demand to keep the hydrogen at these temperatures are significant. As a result, hydrogen should be liquefied as close to the port as possible, and cryogenic pipelines should be kept as short as possible. As before, enough storage will be allowed for 150% of a shipping parcel.

Hydrogen liquefaction should be located at port, or at the most, no more than 1 km away from the port. A liquid hydrogen transmission pipeline is very specialised. It has to be above-ground and vacuum insulated, and when not in operation, the pipeline inventory and temperature need to be managed. It needs to be regularly checked for potential leaks and cracks. Hydrogen molecules are very small and may leak easily having the potential to cause fire hazards that may not be easily detected. Hydrogen is flammable at a very wide concentration range in air and burns with an almost invisible flame.

Organic carrier (MCH)

Toluene is a commodity chemical which is internationally traded. It may be saturated with hydrogen and utilised as hydrogen carrier. The toluene is shipped in a parcel, unloaded and stored, and then saturated at a process plant to produce MCH. The MCH is then stored, loaded and then shipped to its export market, at which point it has to be processed to extract the hydrogen and recover the toluene. The recovered toluene is then shipped back and the cycle repeated. To reduce the transmission cost and logistics associated with transmitting large volumes of flammable chemicals, the toluene and MCH should be stored close to port and the saturation plant also located as close as possible.

While again there are no technical reasons to locate the plant close to port, that is, the underground pipelines could be as long as required, there are economic and safety implications with long pipelines that should be avoided. This is particularly the case for pipelines that are loading ships. These are typically larger pipelines with high capacity in order to quickly fill ships in order to minimise time in port.

MCH remains a liquid at ambient temperatures and pressures, which makes it relatively practical to ship, but it has to be catalytically broken apart at the hydrogen market, requiring a complex plant at market as well as more energy input.

4.4.3 Infrastructure corridors

Ideally infrastructure corridors would be developed by the State or Local Governments to limit a number of routes and corridors being created from private industry. Both Townsville and Gladstone have the potential to secure corridors for pipelines or connections to existing road/rail networks, however specific reviews would be needed closer to the port export locations where additional service constraints exist.

4.4.4 Port landing and storage requirements

There are no limits to the practical distance between hydrogen production and export locations, however, it is widely supported that the distance should be kept to a minimum to reduce pipeline/transport costs. Depending on the carrier process, the distance between an integrated plant and port can vary more greatly.

If an integrated plant is not established on port land, a port landing will require additional storage facilities while the resource is awaiting export by vessel. Liquefied hydrogen and refrigerated ammonia will also require considerable energy usage to remain at a suitable condition while awaiting export. The key requirements for hydrogen export ports are detailed in Figure 4-3.

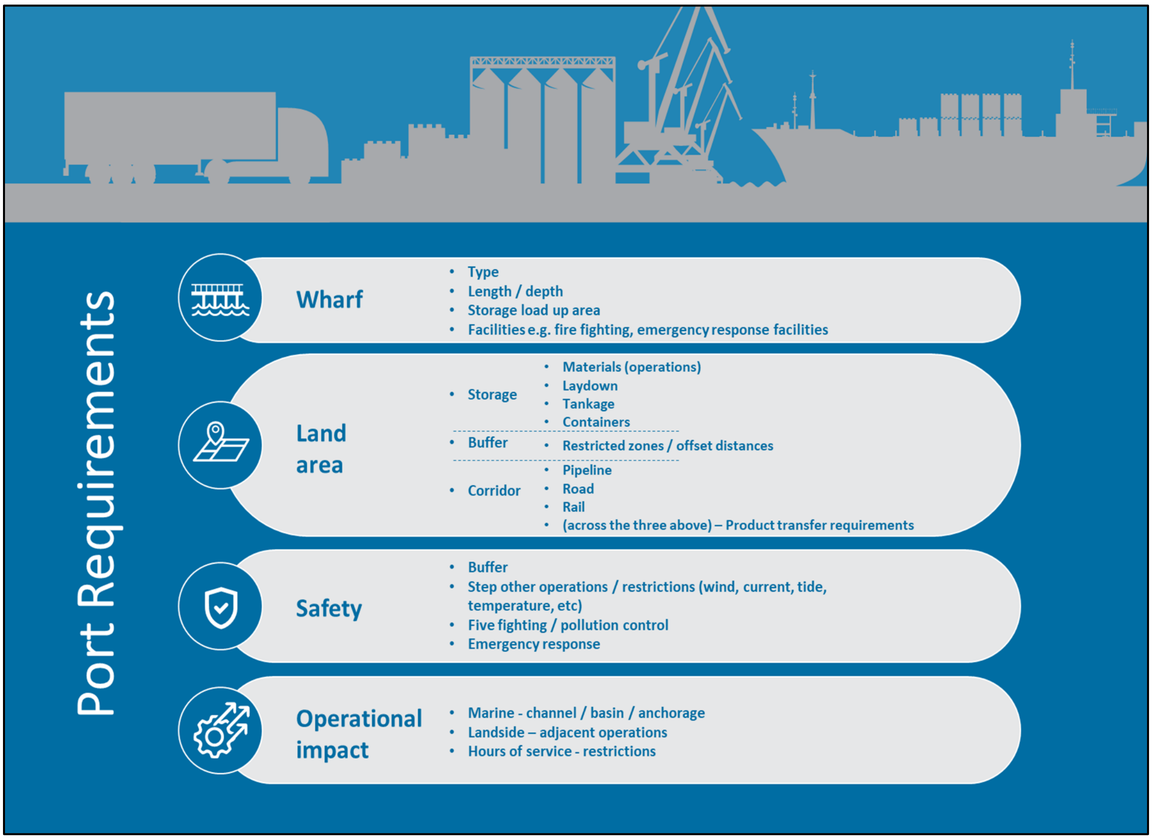

Figure 4-3 Requirements for hydrogen export ports

A range of infrastructure upgrades may be required in order for Australia's ports to be capable of exporting hydrogen at scale. Infrastructure requirements vary according to the chemical state in which the hydrogen is to be transported and the mode on which it is to be transported.

4.4.5 Berth and vessel requirements

There are various factors that impact the type of vessel that should be used. Vessels used to transport hydrogen are likely to resemble those that are used to transport LNG. Based on this, the requirements of hydrogen export berths are likely to resemble those servicing the import and export of natural gas and bulk petroleum products. Specific berth requirements are still relatively uncertain as the vessels are either small trial craft or in the design and development phase. One can assume that the berths and channels that can accommodate vessels designed to carry bulk petroleum products or LNG, will be able to service the new cryogenic liquid-hydrogen bulk-transport vessels. This is because LH2 is much less dense than LNG and consequently the weight of a full load will be less enabling the ship to operate in shallower channels. These assumptions form the basis for the establishment of the minimum requirements for berth dimensions until the specific requirements are better understood.

It is anticipated that the most notable shortfalls in existing infrastructure are likely to pertain to dedicated liquid delivery pipes from storage facilities to the flexible-pipe craned outrigger cranes used to connect the shipside to shore-side piping system. Spare carrying capacity will also be required on the existing jetty infrastructure to allow for the retrofitting of additional pipes and outrigger cranes to accommodate these export mechanisms.

For bulk liquids ports that currently do not handle liquid hydrogen or anhydrous ammonia, large tracts of nearby available land are required close to the jetty infrastructure for port connection and hydrogen / ammonia liquefaction plant production and storage.

4.4.6 Vessel type selection factors

There are various factors that impact the type of vessel that should be used, as detailed in Figure 4-4.

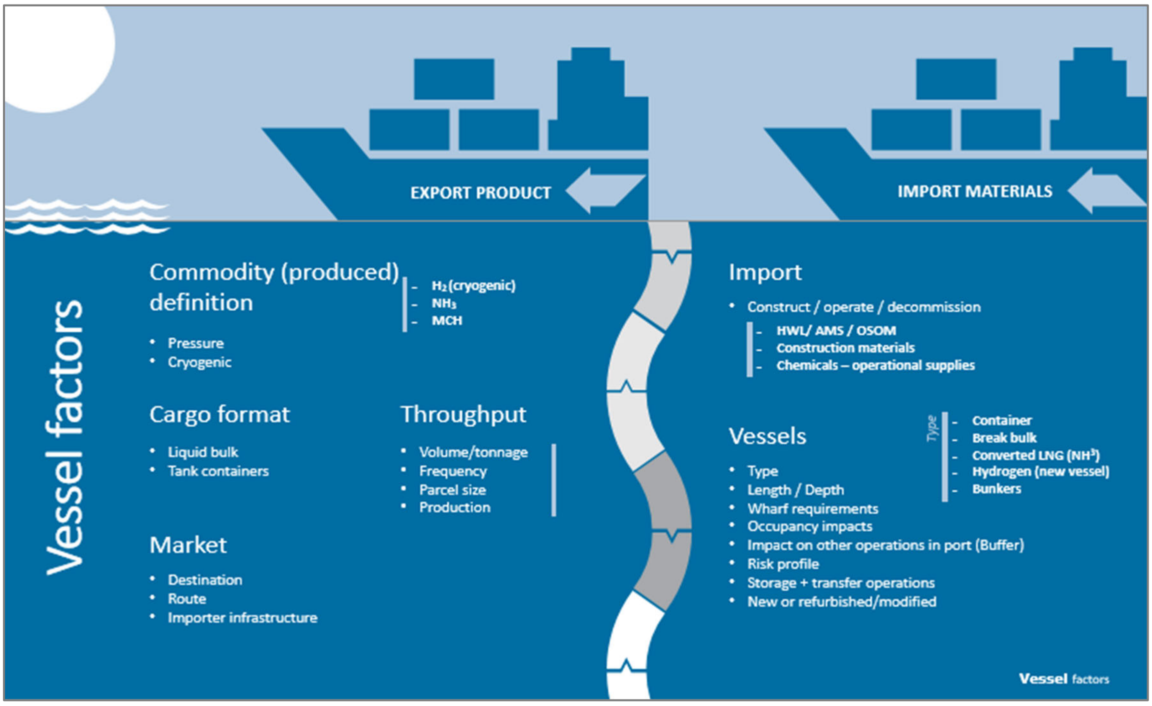

Figure 4-4 Vessel type factors

To form a high-level view of Townsville and Gladstone Port hydrogen export readiness the production scenarios defined in Part 1 of this report have been adopted to inform various likely vessel types.

To ascertain likely vessel types, the density of the transported product in its various chemical compositions has been calculated to generate cubic volumes m^3.

Table 14 identifies the likely vessel sizes and call frequency based on established production scenarios.

Vessel types are based on LNG vessels and are a function of:

- Product type and density (ammonia, MCH, LH2)
- Production scale (as defined in Table 3)
- Likely parcel size (based on production and reasonable vessel calling frequency).

Table 14 Vessel size and frequency*

	Production Scale		
	Size 1***	Size 2	Size 3
Ammonia			
Parcel Size (m^3)	23,000 (based on current small size vessel)	23,000 (based on current small size vessel)	23,000 (based on current small size vessel)
Berths (load hours per annum)	93	372	930
Vessel Size** (m)	160x25x9-10.5	160x25x9-10.5	160x25x9-10.5
Calls (per annum)	3	12	29
LH2			
Parcel Size (m^3)	1,250 (based on small volume existing vessel)	27,000 (based on future mid size vessel)	27,000 (based on future mid size vessel)
Berths (load hours per annum)	608	487	1217
Vessel Size**(m)	116x19x4.5	208x30x9.2	208x30x9.2
Calls (per annum)	97	18	45
MCH			
Parcel Size (m^3)	16,000 (based on current small size vessel)	16,000 (based on current small size vessel)	46,000 (based on current mid size vessel)
Berths (load hours per annum)	348	1,390	927
Vessel Size**(m)	144x23x8-9	144x23x8-9	183x33x10-12
Calls (per annum)	14	56	35

* Based on Table 3 production scenarios
** Length by Beam (Width) by Draft (Depth)
*** Size 1 plant has been calculated for completeness, however outcomes may mean that export at that size may not be viable

Vessel dimensions and port implications

Given the identified production volumes it is broadly evident that the size and frequency of vessels required to export the reference export volumes should not pose major impediment to either Gladstone or Townsville.

In terms of vessel dimensions regarding channel navigation and access the vessels identified as likely export vessels do not appear to breach dimensions as compared to current vessels accessing either port.

Largest reference vessels identified to cater for identified production:

In terms of vessel dimensions the maximum reference vessels identified suitable for the export production volumes are:

- Ammonia: Length: 160 Beam: 25 Draft: 9-10.5 m
- MCH: Length 183 Beam: 33 Draft: 10-12 m
- LH2: Length 208 Beam: 30 Draft: 9.2 m.

Maximum vessel size

The parameters set forth by the maximum vessel sizes for each commodity largely align with the existing capacity of most major ports, including the Port of Townsville and Port of Gladstone.

At the Port of Townsville, the access channels to the port have a total length of 6.4 nautical miles. The channel is 92 metres wide and has a design depth of 11.7 metres. Subject to tide, the maximum vessel size that can be accommodated is 238 metre LOA, 32.2 metre beam and 13.1 metre draft. It can be observed that the above largest reference vessels for each commodity do not exceed these parameters.

The Port of Gladstone limits ship size to 315 metres LOA, beam 55 metres and draft dependent on tide but not likely to exceed 18 metres. The design depth of the Outer Harbour Channel is 16.1 metres but may be less than this between scheduled dredging; a vessel can sail (weather conditions permitting) at 17 metres draft on any day of the year and up to 18 metres draft with the appropriate tide heights. It can be observed that the above largest reference vessels for each commodity do not exceed these parameters.

At a high level, both the Port of Townsville and Port of Gladstone have appropriate channel and berth dimension to accommodate the reference vessels listed across all commodities. However, it should be noted that this does not consider the utilisation and vacancy trends of each facility, the strength and availability of the required landside infrastructure, vessel separating distances and any other limitations that may be present. Additionally, although most ports are capable of handling liquefied chemicals, there are few that currently handle liquid ammonia. Gladstone is one of those ports, and imports approximately 250,000 tpa of anhydrous ammonia.

Further information on the berth pocket size is included in Appendix A.

Ammonia

Although ammonia only requires a temperature of -33°C, ammonia is carried in LPG tankers with full-refrigeration to a minimum of -50°C. Typically, the vessels used to transport ammonia have a capacity of 38,000 cubic metres. The largest vessels that are used for this purpose have a capacity of 88,000 cubic metres.

LH2

The export of liquid hydrogen via maritime transport requires the inclusion of a minimum of one liquid hydrogen storage tank, a hydrogen liquefaction plant, a dedicated hydrogen delivery pipeline or tanker (rail/road) delivery receival gantry for the feedstock, and the related cryogenic transferal equipment from the pipeline or tanker to the production facilities through to storage and then storage to ship.

MCH

MCH is transported in a liquid state at ambient temperatures and pressures. Therefore, the substance could be transported via standard non-refrigerated and un-pressurised chemical tankers. Most ports are already capable of receiving liquid goods from chemical tankers.

4.4.7 Road infrastructure

There are significant road supply chain infrastructure in Gladstone and Townsville local government areas with connectivity to local/regional and interstate road networks (refer to Table 15). The ports connect via local and State-controlled ring roads, which have heavy vehicle and dangerous goods routes approved/preferred by the Department of Transport of Main Roads (DTMR), to the Bruce Highway, Queensland's major primary eastern highway[21].

Table 15 Gladstone and Townsville's road supply chain infrastructure

Supply Chain Infrastructure	Function	Significance
Gladstone		
Bruce Highway	Major state highway connecting to points north and south along the east coast of Queensland	Queensland's primary eastern highway and a significant corridor within the National Land Transport Network
Dawson Highway	Regional highway linking the hinterland in the west to the Bruce Highway and Gladstone	Central Queensland's western highway
Gladstone Mount Larcom Road	State controlled road connecting the Bruce Highway to the GSDA, Fisherman's Landing area and Hanson Road	Key to connecting major port and industry road network with existing highway and haulage routes
Hanson Road, Glenlyon Road, Phillip Street and Bernaraby Road	State controlled roads connecting Gladstone Mount Larcom Road to the port areas between Fisherman's Landing and Boyne Island	Key to connecting major port and industry road network
Port Access Road	Connects Dawson Highway and Hanson Road to Port Central	Essential to connecting port and industry road networks, and providing a safe heavy vehicle road network that bypasses the Gladstone business district, reducing heavy and light/non-commercial vehicle interactions
Landing Road	Provides connection between Fisherman's Landing and Gladstone Mount Larcom Road	Key to connecting major port and industry road networks with existing highway and haulage routes

[21] For more information, refer to DTMR's heavy vehicle route maps and restrictions web page: https://www.tmr.qld.gov.au/business-industry/Heavy-vehicles/Heavy-vehicle-route-maps-and-restrictions

Supply Chain Infrastructure	Function	Significance
Calliope River Road	Provides connection from the Bruce Highway to the GSDA and Gladstone Mount Larcom Road	Key to connecting major port and industry road networks with existing highway and haulage routes
Townsville		
Townsville Port Access Road	Connects the Bruce Highway and Flinders Highway (Stuart Bypass) to the port. Future duplication may be required as port trade increases.	Primary freight road link into the port for B double and type 2 road trains.
Bruce Highway	Connects the port to points north and south along Queensland's east coast as part of the national road network.	Queensland's primary eastern highway.
Flinders Highway (Stuart Bypass)	Connects the port to the western regions, key resources, and agricultural operations in Queensland and the Northern Territory.	North Queensland's primary western highway.
Other local and state road networks, such as Boundary Street and the Townsville ring road	Provides connection for regions to the Port.	Key to connecting major port road networks with existing highways and haulage routes.

Under the *Australian Code for the Transport of Dangerous Goods by Road and Rail*, a contractor and driver of a road vehicle transporting dangerous goods must plan safe routes and adhere to all requirements and restrictions determined by the DTMR. In planning routes for heavy vehicles and dangerous goods, the general principals to apply include:

- Selecting major road corridors
- Avoiding heavily populated and congested areas such as residential areas, central business districts, shopping centers and schools
- Avoiding environmentally sensitive areas
- Avoiding sensitive infrastructure such as tunnels, pipeline corridors or bridges.
- At a site level, an integrated plant should ensure connectivity to the road network that allows for safe access by emergency vehicles, in case of an emergency.

4.4.8 Rail transport

There are several interconnected rail networks that exist within the Gladstone and Townsville local government areas. The transportation of hydrogen and its downstream technologies is not thought to be practicable by rail using the currently available infrastructure. However, it should be noted that a rail line is currently located within proximity to the back side of Fisherman's

Landing in Gladstone. Therefore, it may be feasible to build a spur for the purpose of LH2 and NH3 transportation.

Access by rail to the port infrastructure is via the following as detailed in Table 16.

Table 16 Gladstone and Townsville's rail supply chain infrastructure

Supply Chain Infrastructure	Function	Significance
Gladstone		
North Coast Line	Shared service railway line that is the principal regional freight and passenger line within the Queensland Rail network	Primary line along the Queensland coastline
Moura and Blackwater systems	Forms part of the Central Queensland coal network	Primary line connecting the mines to the port
Townsville		
MIRL	Connects the port to the North West Minerals Province and Phosphate Hill.	Primary line used by the port's minerals and agriculture supply chains.
North Coast Line (NCL)	Connects Townsville to Cairns and Brisbane.	Primary line along the Queensland coastline.
TEARC (proposed)	Future rail line from the MIRL and NCL south of Townsville, parallel to the TPAR and into the port. Redirects rail freight away from urban areas and at grade crossings.	Critical to allowing longer trains to enter the port and increase port operational efficiency.
Two Intermodal Rail Terminals (Stuart)	Provides intermodal connectivity to the TPAR linked to the NCL and the MIRL.	Major road-to-rail facilities for port industry within local rail and road freight network.
Port of Townsville (Jetty) Branch Rail Line	Connects the sidings, cargo handling, and storage facilities within the port to the external rail network.	Major line connecting the NCL and MIRL to the port facilities.

4.5 Surrounding land uses

The model hydrogen plant would typically be classified as a Major Hazard Facility under the *Queensland Work Health and Safety Act, 2011* and most appropriately located within a regional industrial estate designated for higher impact industrial activities. Integrated plants could have spatial requirements of between 2 to 26 hectares, depending on the scale of operation and nature of hydrogen carrier used. State development areas, specialised industrial developments and port-controlled lands typically provide for industries of this scale.

While site area estimates include buffering, being a Major Hazard Facility by virtue of the volume and nature of gases produced and stored on site suggests additional separation from surrounding uses would be prudent. Detailed safety assessments will be required as part of the approval process for each plant, outputs from which would be used in plant design, layout and the establishment of appropriate land use safety procedures for the operation of the plant.

Suitable land uses around these plants would typically be low employment density, larger scale industrial activities in which generous land areas provide additional separation distance in the rare event of a major incident.

Proximity to synergistic activities using waste discharges, such as oxygen or brine, or hydrogen from the plant may be appropriate subject to appropriate land use safety planning.

Plants should not be located adjacent to residential, urban areas or recreational areas to avoid potential impacts associated with plant and traffic noise, light spill and potential gas emissions or other onsite incident. In the case of associated infrastructure corridors, these should be located to avoid these areas.

4.6 Safety and security

A plant with an inventory of more than 50 tonnes of ammonia results in the site being classified as a Major Hazard Facility. This classification triggers an additional level of government overview and site management systems for safety at and around the plant.

In addition to these assessments, site selection considerations related to safety and security would include the following:

- Provision for emergency access. Plant location should allow for access redundancy in case the primary access becomes unavailable (due to incident, flooding etc.)
- Access to a community emergency response capability. Even where this is available, additional onsite procedures would be triggered under the Major Hazard Facility designation
- There should be sufficient on site area for the bunding and storage of any runoff from chemical spills or firefighting runoff, particularly where upstream from sensitive receptors and natural environments
- Retention of maintenance access to, and safety buffers along, pipeline corridors
- The ability to provide security fencing for public safety and security.

It was acknowledged during consultation with DNRME that the current safety and security standards associated with the LNG industry are being applied to hydrogen plants and a performance / risk based assessment is presently the accepted process by which the safety and security of the facility is managed in the absence of specific industry standards. In the future, the parameters that dictate the safety design standards for hydrogen production may change.

5. Land suitability and capability

Land used to develop a hydrogen plant should be generally free from constraints to maximise the allowable development footprint area while safeguarding the existing natural and built environment. The land suitability considerations detailed in Table 17 are sourced from a number of national, State and local databases such as Queensland Globe and local planning scheme mapping. Where land does not meet these below criteria, further investigations may be required, or the land may be too constrained and unsuitable for development of a hydrogen plant.

Table 17 Land suitability criteria

Physical considerations	
Topography	• A suitable site should be sloped with a grade between 1% and 15% to provide for drainage and minimise earthworks.
Geotechnical conditions	• A suitable site should contain geotechnical conditions able to cope with the design loads • A suitable site's soils should allow for ease of trenching during construction phases • A suitable site should not encounter shallow groundwater.
Drainage	• A suitable site should achieve a lawful point of discharge, with sufficient space to allow for onsite management (if required).
Flooding	• A suitable site and its access points should achieve a flood immunity of 1%-year annual exceedance probability • A suitable site should be immune from storm surges/seal level rise.
Onsite vegetation	• A suitable site should not contain/limit the presence of regulated vegetation.
Sensitive natural environments	• A suitable site should be buffered from sensitive natural environments to avoid impacts from potential discharges from emergency events.
Airshed considerations	
Predominant winds	• A suitable site should, preferably, be downwind from nearby incompatible land use and sensitive receptors.
Regional topography/airsheds	• A suitable site should be located in airshed that avoids concentration of potential emission sources and allows for emission dispersal.
Infrastructure considerations	
Availability/capability of utility networks	• A suitable site should have access to water, sewer, electricity and telecommunications that are capable of supporting the hydrogen plant.

Transport network connectivity	• A suitable site should contain access to transport networks with a stable flow of traffic away from sensitive uses, with direct access to downstream technology locations • A suitable site should design crossovers and driveways to allow access by emergency vehicles, in case of an emergency • A suitable site for large scale plants would have access to an infrastructure corridor for the transport of product to a port.
Land use considerations	
Tenure	• A suitable site should occupy freehold or leasehold land. • A suitable pipeline corridor should occupy leasehold land. • Land where native title cannot be extinguished may not be suitable. Where avoidance is not possible, early and frequent negotiation/communication with native title parties and the potential development of Indigenous Land Use Agreements should be undertaken.
Area for expansion	• A suitable site should contain an area that provides opportunity for plant expansion as demand for hydrogen production grows.
Synergistic activities	• A suitable site should co-locate synergistic activities onsite, where possible, to maximise efficiencies.

6. Planning framework

Queensland's planning framework is established by the *Planning Act 2016* and is instrumental in regulating development and guiding growth. There are a range of tools given effect by the *Planning Act 2016* to support three main systems: plan making, development assessment and dispute resolution.

This framework currently neglects to provide a streamlined approval pathway for hydrogen production facilities and ancillary infrastructure such as renewable energy and refuelling stations. To close this gap, the Queensland Government intend to collaborate with other jurisdictions to develop an agreed upon policy framework for the emerging hydrogen industry. In the interim, the Queensland Government has established a hydrogen inter-departmental working group to coordinate hydrogen-related activities across the State's departments[22].

The Queensland Government has also published the Queensland Hydrogen Investor Toolkit intended to *"assist investors with project planning for hydrogen developments in Queensland. It provides an overview of the planning and other regulatory approvals information in Queensland."*[23] The document is not static in that it will be regularly updated as engagement with project proponents and experience with hydrogen projects feeds new information[24].

The Queensland Hydrogen Investor Toolkit provides advice and guidance on the legislative framework and appropriate planning pathways. This document should be referenced for further information on relevant regulatory controls.

22 State of Queensland, Department of State Development, Manufacturing, Infrastructure and Planning, 2019

23 State of Queensland, Department of State Development, Tourism and Innovation, 2020

24 For the latest version of the investor toolkit, refer to http://www.dsdmip.qld.gov.au/resources/strategy/queensland-hydrogen-investor-toolkit.pdf

7. MCA criteria

The preceding sections of this report have identified the spatial and infrastructure requirements for the establishment of a hydrogen plant and its downstream technologies that can be used in the selection and evaluation of alternative sites. The following matrix combines the criteria previously identified into a consolidated table for ease of reference and identifications.

The weightings of the criteria will be dependent on the final desired plant configuration and production market i.e. integrated plant with production for export, or a decentralised plant with production for domestic use. The information contained within Table 18 provides criteria based on the integrated plant scenario. A more detailed matrix is provided in Appendix B, the information within the matrix provides the next level of detail, which is the supporting inputs for Table 18 below.

Table 18 MCA for hydrogen plant

	Production			Downstream technologies								
	H_2			Ammonia			H_2 liquefaction			MCH (organic carrier) conversion		
	Size 1	Size 2	Size 3	Size 1	Size 2	Size 3	Size 1	Size 2	Size 3	Size 1	Size 2	Size 3
	8,687 tpa	34,748 tpa	86,870 tpa	46,504 tpa	180,017 tpa	465,043 tpa	8,513 tpa	34,053 tpa	85,133 tpa	139,050 tpa	556,200 tpa	1,390,499 tpa
Non-derivative specific												
Preferred zoning	Industry Zoning (Industry Zone, Low Impact Industry Zone, Medium Impact Industry Zone, High Impact Industry Zone, Special industry Zone, Industry Investigation Zone)											
Environmental	A site should be generally free from constraints having regard to physical, airshed, infrastructure, and land use considerations. Where land is constrained, further investigations may be required, or the land may be too constrained and unsuitable for development of a hydrogen plant / downstream technologies.											
Legislative approval pathway	• Commonwealth approvals • Overarching project approvals: – Option 1: material change of use development approval and determination of a major hazard facility – Option 2: co-ordinated project and determination of a major hazard facility • Specific assessable development approvals.											
Tenure	Freehold (site) or leasehold (site and pipeline corridor)											
Native Title	Site to have Native Title extinguished											
Derivative Specific												
General												
Site (m^2) *(land area + storage)*	4,375	18,375	45,938	14,418	54,329	111,480	6,959	36,473	61,373	26,415	84,020	207,549
Land area (m^2)	4,375	18,375	45,938	9,160	36,640	91,599	4,150	16,600	41,500	9,855	39,500	100,000
Storage (m^2)[25]	1,352	4,046	7,700	5,258	17,689	19,881	2,809	19,873	19,873	16,560	44,520	107,549
Tank arrangement [18]	2 tanks (13m dia)	4 tanks (17m dia)	6 tanks (20m dia)	2 tanks[26] (12m dia)	4 spheres (22m dia)	4 spheres (24m dia)	1 sphere (15m dia)	6 spheres (24m dia)	6 spheres (24m dia)	4 spheres (20m dia)	4 spheres (20m dia)	8 spheres (24m dia)
Tank footprint (m^2)	265	908	1885	226	1,521	1,809	177	2,715	2,715	1,257	1,257	5,620
Separation distances[27]												
Min (m)	5.8[28]	5.8	5.8	38	45	45	23	23	23	3	3	3
Max (m)	14[29]	14	14	150	180	180				10	10	10
Infrastructure (Power)												
Use (MW)	77	308	770	10	41	102	7	29	73	2	6	16
Power line distance limit @ 33kV (km)	Not suitable	Not suitable	Not suitable	150	40	Not suitable	210	60	Not suitable	+500	240	100

25 Product storage for H2 is minimal, storage is for brine based on 30 day retention and half diameter separation between tanks.

26 For most tank arrangements, a separation of one tank diameter is assumed between tanks. Added to that is a standard requirement for separation of tanks from a fence line, road or equipment.

27 Standard separation distances have been adopted from AS2022, Table 3.1.

28 Separation distance for bulk compressed gaseous hydrogen from most equipment/objects.

29 Separation distance for bulk compressed gaseous hydrogen from roads, buildings, fence lines.

	Production			Downstream technologies								
	H_2			Ammonia			H_2 liquefaction			MCH (organic carrier) conversion		
	Size 1	Size 2	Size 3	Size 1	Size 2	Size 3	Size 1	Size 2	Size 3	Size 1	Size 2	Size 3
	8,687 tpa	34,748 tpa	86,870 tpa	46,504 tpa	180,017 tpa	465,043 tpa	8,513 tpa	34,053 tpa	85,133 tpa	139,050 tpa	556,200 tpa	1,390,499 tpa
Power line distance limit @ 66kV (km)	80	Not suitable	Not suitable	+500	150	60	+500	210	80	150	150	120
Power line distance limit @ 132kV (km)	300	70	30	+500	+500	220	+500	+500	300	+500	+500	380
Power line distance limit @ 2275kV (km)	>500	300	120	+500	+500	+500	+500	+500	+500	+500	+500	+500
Infrastructure (Water)												
Use (electrolyser + brine H_2 only) (ML/a)	136	543	1335	3	11	29	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable
Disposal (ML/a)	32	125	313	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable
Co-locating activities	No	No	No	With hydrogen production/connected with pipeline to hydrogen production/co-located at port/connected to port with pipeline			With hydrogen production/connected with pipeline to hydrogen production/location at port preferred.			With hydrogen production/connected with pipeline to hydrogen production/location at port preferred.		
Infrastructure (Transport)												
Road (t/truck) – bulk product	0.215 (tube trailer at 20 MPag) - 0.615 (cylinders on truck at 30 MPag) Calculated 0.376 tonnes / tube trailer Alternative transmission for gaseous hydrogen is a hydrogen pipeline, or injection into a natural gas pipeline (most NG pipeline material selection will allow for up to 20 mole% H_2 in the line)			21 (assume single trailer / tank combination)	42 (assume B-double with 2 x tank)	42 (assume B-double with 2 x tank)	2.17 (assume single trailer / tank combination)	4.34 (assume B-double with 2 x tank)	4.34 (assume B-double with 2 x tank)	22 (assume single trailer / tank combination)	44 (assume B-double with 2 x tank)	44 (assume B-double with 2 x tank)
Trucks dispatched (per annum)	23,133 (63 per day)	92,352 (254 per day)	231,330 (634 per day)	2,212 (6 per day)	4,424 (12 per day)	11,060 (30 per day)	3,923 (11 per day)	7.846 (21 per day)	19,616 (54 per day)	6,268 (17 per day)	12,535 (34 per day)	31,338 (86 per day)
T50 ISO Tank Containers (t/ISO)	Not Applicable	Not Applicable	Not Applicable	14.3	14.3	14.3	Not Applicable	Not Applicable	Not Applicable	15.1	15.1	15.1
ISO (per annum)	Not Applicable	Not Applicable	Not Applicable	3,250 (9 per day)	13,001 (36 per day)	32,502 (89 per day)	Not Applicable	Not Applicable	Not Applicable	9,210 (25 per day)	36,839 (101 per day)	92,096 (252 per day)
Rail (t/carriage) – bulk product	Assume same load as road tube trailer	Assume same load as road tube trailer	Assume same load as road tube trailer	38	38	38	8.3	8.3	8.3	38	38	38
Carriages (per annum)	Same as road tube trailer	Same as road tube trailer	Same as road tube trailer	1,225 (3 per day)	4,900 (13 per day)	12,251 (34 per day)	1,027 (3 per day)	4,109 (11 per day)	10,272 (28 per day)	3,699 (10 per day)	14,796 (41 per day)	36,990 (101 per day)
Number trains (per annum)	276 (0.75 per day)	1,102 (3 per day)	2,754 (7.6 per day)	27.84 (0.08 per day)	111.4 (0.31 per day)	278.5 (0.76 per day)	12.3 (0.03 per day)	49 (0.13 per day)	122.3 (0.34 per day)	82 (0.23 per day)	329 (0.9 per day)	822 (2.25 per day)
Infrastructure (Port)												
Berths (load hours per annum)	Not Applicable			93	372	930	608	487	1217	348	1,390	927

	Production			Downstream technologies								
	H_2			Ammonia			H_2 liquefaction			MCH (organic carrier) conversion		
	Size 1	Size 2	Size 3	Size 1	Size 2	Size 3	Size 1	Size 2	Size 3	Size 1	Size 2	Size 3
	8,687 tpa	34,748 tpa	86,870 tpa	46,504 tpa	180,017 tpa	465,043 tpa	8,513 tpa	34,053 tpa	85,133 tpa	139,050 tpa	556,200 tpa	1,390,499 tpa
Vessel calls (per annum)	Not Applicable			3 (based on current small size vessel – 23,000m^3)	12 (based on current small size vessel – 23,000m^3)	29 (based on current small size vessel – 23,000m^3)	97 (based on small volume existing vessel – 1,250m^3)	18 (based on future mid size vessel – 27,000m^3)	45 (based on future mid size vessel – 27,000m^3)	14 (based on current small size vessel – 16,000m^3)	56 (based on current small size vessel – 16,000m^3)	35 (based on current mid size vessel – 46,000m^3)
Storage	Not Applicable			As for plant storage – one or the other should be allowed for. Generally preferred to produce hydrogen carrier close to port and store for practical and economic reasons. Most likely carrier to produce away from port is ammonia.								

8. Key findings and next steps

8.1 Hydrogen requirements for success

Development scenarios were established for three varied sizes of hydrogen plants, which can be integrated with co-location of downstream technologies. In this part of the Study, the likely key requirements of each development scenario were also calculated.

The development of scenarios for an MCA identified a number of requirements, grouped broadly into the following categories:

- **Land use planning**: land preconditions for plant suitability including preferred zoning, environmental constraints, and tenure
- **Typical spatial requirements**: general size requirements for plant footprint including buildings, storage, and tanks
- **Separation distances**: minimum and maximum distances for bulk hazardous goods from most equipment/objects including roads, buildings, and fence lines
- **Infrastructure (transport)**: number and volume of trucks/carriages to transport bulk hazardous goods per annum
- **Infrastructure (port)**: regarding export pre-storage, vessel calls per annum and load hours at the berth
- **Infrastructure (power)**: megawatt usage requirements and maximum power line distance limit for different voltage
- **Infrastructure (water)**: megalitre usage and disposal requirements.

The development of the above requirements and overall criteria will allow for the evaluation of possible location within Queensland.

8.2 Next steps

Based on the outcomes of this Part 2 report, the following are the recommended next steps which form Part 3 of the study:

- Workshop with the DSDTI to agree on the Part 2 report findings including criteria and application process
- Development of MCA and weightings based on agreed criteria
- Identify appropriate areas within the region including Gladstone and Townsville SDA and other existing or proposed industrial areas.

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Appendices

Appendix A – Berth Pocket Size

Port of Gladstone

Berth	Berth Pocket Length (m)	Max Vessel LOA (m)	Wharf Height Above Lat (m)	Max Berthing Displacement (t)	Air Draft (m) LAT	Berth Pocket Width (m)	Max Vessel DWT (t)
Boyne Smelter	355.0	230.0	6.1	75,000	26	50.0	60,000
(Alumina) South Trees East (Caustic /Fuel Oil)	270.9	200	6.0	110,000	26	50.0	110,000
	270.9	230	6.0	110,000	22	50.0	110,000
South Trees West	270.9	255	6.0	110,000	14.5	50.0	90,000
Barney Point	320.0	270	6.1	87,000	17.7	48.0	150,000*
Auckland Point No 1	259.0	238	5.6	45,000	15.9	40.0	65,000
Auckland Point No 2	255.0	198	5.5	32,000	17.5	40.0	60,000
(Fuel) Auckland Point No 3 (Containers) (Other)	230.0	190	5.6	55,000	NA	40.0	35,000*
	230.0	190	5.6	55,000	NA	40.0	35,000*
	230.0	190	5.6	55,000	NA	40.0	35,000*
Auckland Point No 4	300	255	5.5	85,000	NA	40.0*	70,000
RG Tanna Coal Terminal No 1	380.0	315	12.3	140,000	18.5	70.0	220,000
RG Tanna Coal Terminal No 2	369.4	315	12.3	140,000	18.5	70.0	220,000
RG Tanna Coal Terminal No 3	388.9	315	12.3	140,000	18.5	70.0	220,000
RG Tanna Coal Terminal No 4	390.0	315	12.3	140,000	18.5	70.0	220,000

Berth	Berth Pocket Length (m)	Max Vessel LOA (m)	Wharf Height Above Lat (m)	Max Berthing Displacement (t)	Air Draft (m) LAT	Berth Pocket Width (m)	Max Vessel DWT (t)
Wiggins Island Coal Terminal	431.0	320	11.75	191,000	21.0	71.0	220,000
Fisherman’s Landing No 1	296.8	235	8.3	90,000	29.5	65.0	80,000
Fisherman’s Landing No 2	296.8	235	8.3	90,000	29.5	65.0	80,000
	296.8	235	8.3	90,000	29.5	65.0	80,000
	296.8	235	8.3	90,000	29.5	65.0	80,000
Fisherman's Landing No 4	226.0	190	6.5	31,000	20.5	50.0	25,000
Fisherman's Landing No 5	374.0	200	7.1	44,000	NA	50.0	35,000
APLNG	325.0	316	10.47	143,000	NA	50.0	106,898
QCLNG	365.0	315	9.0	146,950	NA	60.0	NA
GLNG	496.0	315	7.00	153,000	NA	100.0	121,000

Port of Townsville

Berth	Berth Pocket Length (m)	Max Vessel LOA (m)	Height above LAT (m)	Design Depth (m)	Maximum Berthing Displacement
1	250	238	5.46	13.6	90,000
2	281	238	6.07	12.2	90,000
3	283	238	6.07	12.2	90,000
4	220	220	6.07	12.2	70,000 @ 0.11m/s g 140,000 @ 0.09m/s g
8	240	220	5.77	12.5	70,000
9	248	238	5.77	12.2	90,000
10	320	238	5.8	12	50,000
11	240	225	9.45	12.2	55,000

Appendix B – Plant Calculations

		Plant Size		
Parameter		1	2	3
Hydrogen Production				
H2 production capacity	**tpa**	**8,687**	**34,748**	**86,870**
Power (Grid connection in separate section below)				
Power consumption (electrolysers)*	MW	70	280	700
Power consumption (Hydrogen plant including auxilliaries)	MW	77	308	770
Water				
Water consumption (electrolysers only)	ML/a	104	417	1042
Brine produced (assume 1000 mg/L TDS)	ML/a	31	125	313
Raw Water consumption Demin Plant	ML/a	136	542	1355
Raw water pipeline diameter, 90% cap factor	NB mm	80	150	200
Water Treatment Discharge (Brine)				
Brine Storage (30 days)	ML	2.6	10	26
Number of tanks		2	4	6
Tank diam (assume 0.8 aspect ratio and 90% usable	m	13	17	20
Hydrogen				
Hydrogen storage		Small - process buffer	Small - process buffer	Small - process buffer
Footprint				
Area Required for water treatment and brine storage	m2	1352	4046	7700
Area for Electrolyser units only	m2	1750	7350	18375

Typical footprint electrolysers and supporting equipment (water treatment, utils) only	m2	4375	18375	45938
Streams from Plant				
Hydrogen				
Hydrogen Pipeline diameter @15MPa, 40C, 90% cap factor	NB mm	50	100	150
Road transport option (tube trailer)	t/truck	0.25	0.25	0.25
Trucks dispatched per annum		*34748*	*138992*	*347480*
Brine				
Brine pipeline diameter, 90% cap factor (min 50mm)	NB mm	50	50	80
Road transport option (tube trailer)	t/truck	30	30	30
Trucks dispatched per annum		*31273*	*125093*	*312732*
Ammonia production				
Ammonia Production Capacity	**tpa**	**46504**	**186017**	**465043**
	tpd	141	564	1409
Power (Grid connection in separate section below)				
Power use	MW	10	41	102
Power line distance limit @ 33kV	km	150	40	15
Power line distance limit @ 66kV	km	>500	150	60
Power line distance limit @ 132kV	km	>500	>500	240
Water	ML/a	3	11	29
Other utilities		Cooling water, steam, fuel gas		
Ammonia				
Buffer Storage on site (not required for integrated plant)	days	2.0	2	2
	t	282	1127	2818

	m3	386	1544	3861
Sphere diameter	m	9	12	13
Sphere volume	m3	382	905	1150
Number of spheres		1	2	4
Buffer distances storage (as per AS 2022, Table 3.1), max	m	150	180	180
Buffer distances storage (as per AS 2022, Table 3.1), min (assuming fenced secure premise as per Table 3.1 footnote)	m	38	45	45
Streams from Production Plant				
Pipeline for transfer to separate shipping storage site	NB mm	**50**	**100**	**150**
Road transport option T50	t/truck	15	30	30
Trucks dispatched per annum		3100	6201	*15501*
Rail carriage capacity (assume isotainer)	t/carriage	17.5	17.5	17.5
Carriages per annum		2654	10617	*26544*
Chilling and Shipping storage				
Capacity as % of ship parcel load		150%	150%	150%
Storage capacity required	m3	33000	33000	33000
Tank volume	m3	33167	33167	33167
Tank(s) dimensions	DxH	21x12.5		
Number of tanks		1	1	1.00
Buffer distances storage (as per AS 2022, Table 3.1), max	m	180	180	180
Buffer distances storage (as per AS 2022, Table 3.1), min (assuming fenced secure premise as per Table 3.1 footnote)	m	45	45	45

Pipeline for ship fill (assume 24 hr load time)	NB mm	**350**	**350**	**350**
Shipping Transport assumptions				
Ship Parcel size	m3	22000	22000	22000
Ship Vessel Size*		160x25x9-10.5m	160x25x9-10.5m	160x25x9-10.5m
Ship Calls Per Annum		*3*	12	29
Footprint				
Separate Plants				
Production plant only	m2	9160	36640	91599
Buffer Storage Footprint	m2	4662	8694	12851
Production Plant and Buffer storage Footprint	m2	13822	45334	104450
Chilling and shipping storage footprint using min buffer distance	m3	15876	15876	15876
Integrated Plant	**m2**	**25036**	**52516**	**107475**
H2 liquefaction				
Production	**tpa**	**8513**	**34053**	**85133**
	m3/annum	119905	479620	1199051
	tpd	26	103	258
Power Use (Grid connection in separate section below)	MWh/h	7	29	73
Power line distance limit @ 33kV	km	150	40	15
Power line distance limit @ 66kV	km	>500	150	60
Power line distance limit @ 132kV	km	>500	>500	240
Other utilities		Cooling water	Cooling water	Cooling water
Shipping Storage				
Shipping assumptions				
Parcel size	m3	1,250	27,000	27,000
Parcels per annum		97	18	45
Capacity as % of ship parcel load		150%	150%	150%

Storage capacity required	m3	1,875	40,500	40,500
Sphere diameter	m	18	25	25
Sphere volume per sphere	m3	2226	5964	5964
Number of spheres		1	7	7
Buffer distance (NFPA2 bulk liq H2 storage Table 8.3.2.3.1.6(A))	m	23	23	23
Distance between spheres	m	1 diameter	1 diameter	1 diameter
Liquid hydrogen transport to ship options				
Pipeline for ship fill (assume 24 hr load time)	NB mm	**100**	**400**	**400**
Road transport option T50	t/truck	3.6	3.6	
	m3/truck	50	50	
Trucks dispatched per annum		2,398	9,592	
Footprint				
Hydrogen Liquefaction Process Plant footprint	m2	4,150	16,600	41,500
Storage footprint	m2	4,096	27,429	27,429
Liq footprint & storage	**m2**	**8,246**	**44,029**	**68,929**
MCH (organic carrier) conversion				
Production	**tpa**	**139,050**	**556,200**	**1,390,499**
	tpd	421	1,685	4,214
Power use	MWh/h	1.6	6.3	15.8
Other utilities		Steam, fuel gas, cooling water		
Footprint plant	m2	9855	39500	100000
Storage assumptions				
Toluene storage	t	8670	8670	34680
	m3	10000	10000	40000
Number of tanks		5	5	8
Tank capacity each	m3	2000	2000	5000
Tank diameter each	m	18	18	18

Separation distance from fence, on-site storage (Table 5.3 AS 1940, C2 liquid so no restriction described)	m	3	3	3
Selected separation between tanks	m	1 diameter	1 diameter	1 diameter
Separation from protected location off-site	m	11	11	15
Storage layout		9877	9877	13622
MCH shipping parcels	m3	10000	10000	40000
Parcel frequency	times/annum	14	56	35
MCH storage	m3	15000	15000	60000
Sphere capacity each	m3	4189	4189	7238
Number of spheres	m	4	4	8
Separation distance from fence, on-site storage (Table 5.3 AS 1940, C2 liquid so no restriction described)	m	10	10	10
Selected separation between spheres	m	1 Diameter	1 Diameter	1 Diameter
Separation from protected location off-site	m	15	15	15
Storage layout		12769	12769	26257
Footprint plant + storage	**m2**	**31077**	**92714**	**220400**
Pipeline for ship fill and unloading (assume 24 hr load time)	mm NB	200	200	350

		Maximum Distance for Power Grid Connection (km)		
Hydrogen Plant Alone	**MW**	**77**	**308**	**770**
Power line distance limit @ 33kV	km	Not Suitable	Not Suitable	Not Suitable
Power line distance limit @ 66kV	km	80	Not Suitable	Not Suitable

Power line distance limit @ 132kV	km	300	70	30
Power line distance limit @ 275kV	km	500+	300	120
Ammonia Plant Alone	**MW**	**10**	**41**	**102**
Power line distance limit @ 33kV	km	150	40	Not Suitable
Power line distance limit @ 66kV	km	500+	150	60
Power line distance limit @ 132kV	km	500+	500+	220
Power line distance limit @ 275kV	km	500+	500+	500+
LH2 Plant alone	**MW**	**7**	**29**	**73**
Power line distance limit @ 33kV	km	210	60	Not Suitable
Power line distance limit @ 66kV	km	500+	210	80
Power line distance limit @ 132kV	km	500+	500+	300
Power line distance limit @ 275kV	km	500+	500+	500+
MCH Plant Alone	**MW**	2	6	16
Power line distance limit @ 33kV	km	500+	240	100
Power line distance limit @ 66kV	km	500+	500+	380
Power line distance limit @ 132kV	km	500+	500+	500+
Power line distance limit @ 275kV	km	500+	500+	500+
Integrated Ammonia Plant	**MW**	**87**	**349**	**872**
Power line distance limit @ 33kV	km	Not Suitable	Not Suitable	Not Suitable
Power line distance limit @ 66kV	km	70	Not Suitable	Not Suitable
Power line distance limit @ 132kV	km	270	60	25
Power line distance limit @ 275kV	km	500+	270	110
Integrated LH2 Plant	**MW**	**84**	**337**	**843**

Power line distance limit @ 33kV	km	Not Suitable	Not Suitable	Not Suitable
Power line distance limit @ 66kV	km	70	Not Suitable	Not Suitable
Power line distance limit @ 132kV	km	270	60	30
Power line distance limit @ 275kV	km	500+	270	110
Integrated MCH Plant	**MW**	**79**	**314**	**786**
Power line distance limit @ 33kV	km	Not Suitable	Not Suitable	Not Suitable
Power line distance limit @ 66kV	km	80	Not Suitable	Not Suitable
Power line distance limit @ 132kV	km	290	70	30
Power line distance limit @ 275kV	km	500+	290	120

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