Australian Hydrogen Centre

10% Hydrogen Distribution Networks South Australia Feasibility Study

Assessing the feasibility of delivering 10% renewable hydrogen in South Australia's gas distribution networks

May 2023


Acknowledgement of Country
The Australian Hydrogen Centre acknowledges Aboriginal and Torres Strait Islander people, and their lands on which we work, which support and sustain the energy systems we study.
We pay our respects to their Elders, past and present. We commit to reflecting that respect in the ways we carry out our work.
Yankalilla SA, Australia
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This project received funding from the Australian Renewable Energy Agency (ARENA) as part of ARENA's Advancing Renewables Program.

Executive Summary

The Australian Hydrogen Centre (AHC) was established to deliver an Australian-first feasibility study of how existing natural gas distribution networks could be used in a in a system to produce, store, and transport renewable hydrogen, decarbonising gas supply while still meeting the needs of millions of customers.

This follows the Australian National Hydrogen Strategy's identification of hydrogen in gas networks as one of three large-scale activation markets to build demand[1]. The Strategy outlined that taking early steps to use hydrogen in transport, industrial use and gas networks will complement and enhance the impact of hydrogen hubs on making hydrogen infrastructure more cost-effective, promoting efficiencies, fostering innovation, and encouraging sector coupling synergies[2].

The $4.15 million AHC project, supported by the Australian Renewable Energy Agency (ARENA), the Victorian Government and the South Australian Government, has brought together expertise and knowledge from across the energy supply chain including renewable electricity producers, electricity and gas infrastructure owners, and retailers to produce this comprehensive research.

The reports show that it is technically and economically feasible to use existing gas infrastructure for scaled hydrogen distribution. More specifically, 10% renewable hydrogen in South Australian gas distribution networks could:

- immediately reduce the carbon emissions of the existing gas supply by 34,096 t CO2-e while developing the renewable hydrogen market;
- unlock the opportunity to harness underutilised renewable generation infrastructure to supply 90 MW of electrolyser capacity, and 6 tonnes of short-term hydrogen storage by 2030.
- ramp up hydrogen production to almost 550 TJ/annum by 2030, strengthening demand for domestic hydrogen offtakes and creating 88 South Australian jobs during construction (22 ongoing).

Supported by a range of independent technical studies, the AHC's focus was to determine how a 10% renewable hydrogen distribution system could optimally be achieved for supply to households, businesses and industry and is not a detailed scenario analysis on decarbonising the wider economy.

The reports provide a better understanding of the opportunity to access Australia's world-class gas distribution infrastructure to unlock its hydrogen opportunity whilst retaining energy security and affordability, and identifies a range of low-regret enablers that could trigger coordinated action by government and industry.

1 See page 33 of the National Hydrogen Strategy, found here: https://www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf

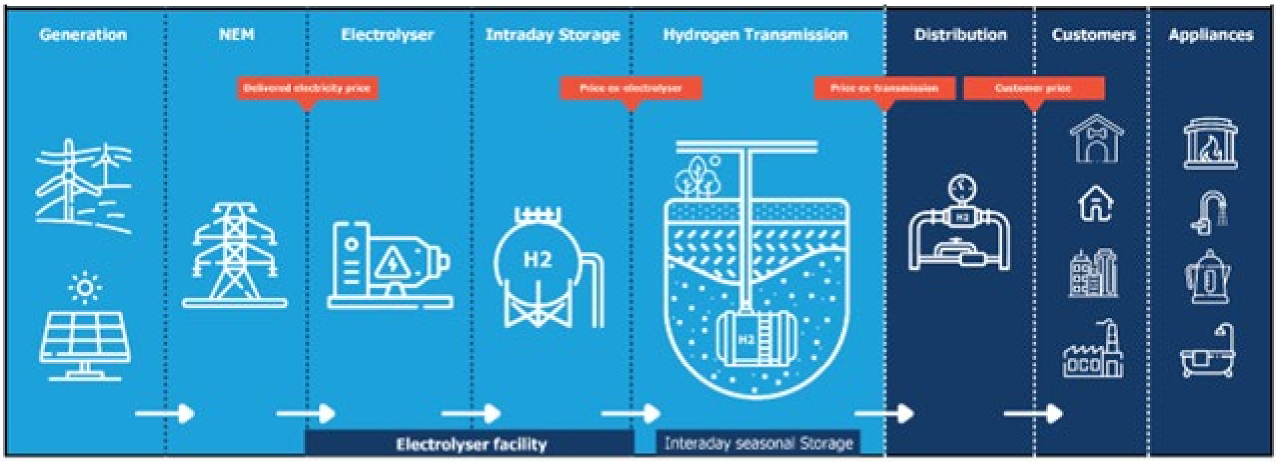
2 See page viii of the National Hydrogen Strategy, linked above.

Report Scope and Limitations

There are various plausible ways that renewable hydrogen production and distribution supply chains could develop to achieve 10% hydrogen in networks; however, the AHC considered the most plausible at this point in time.

Figure 1 indicates the key features of this supply chain, and also demonstrates the scope of this Study. It shows renewable electricity delivered by the National Electricity Market (NEM) to power electrolyser plants producing renewable hydrogen, which is then stored (as/if required), blended with natural gas at 10% volumes, and supplied through existing gas distribution networks for use by domestic, commercial, and industrial customers.

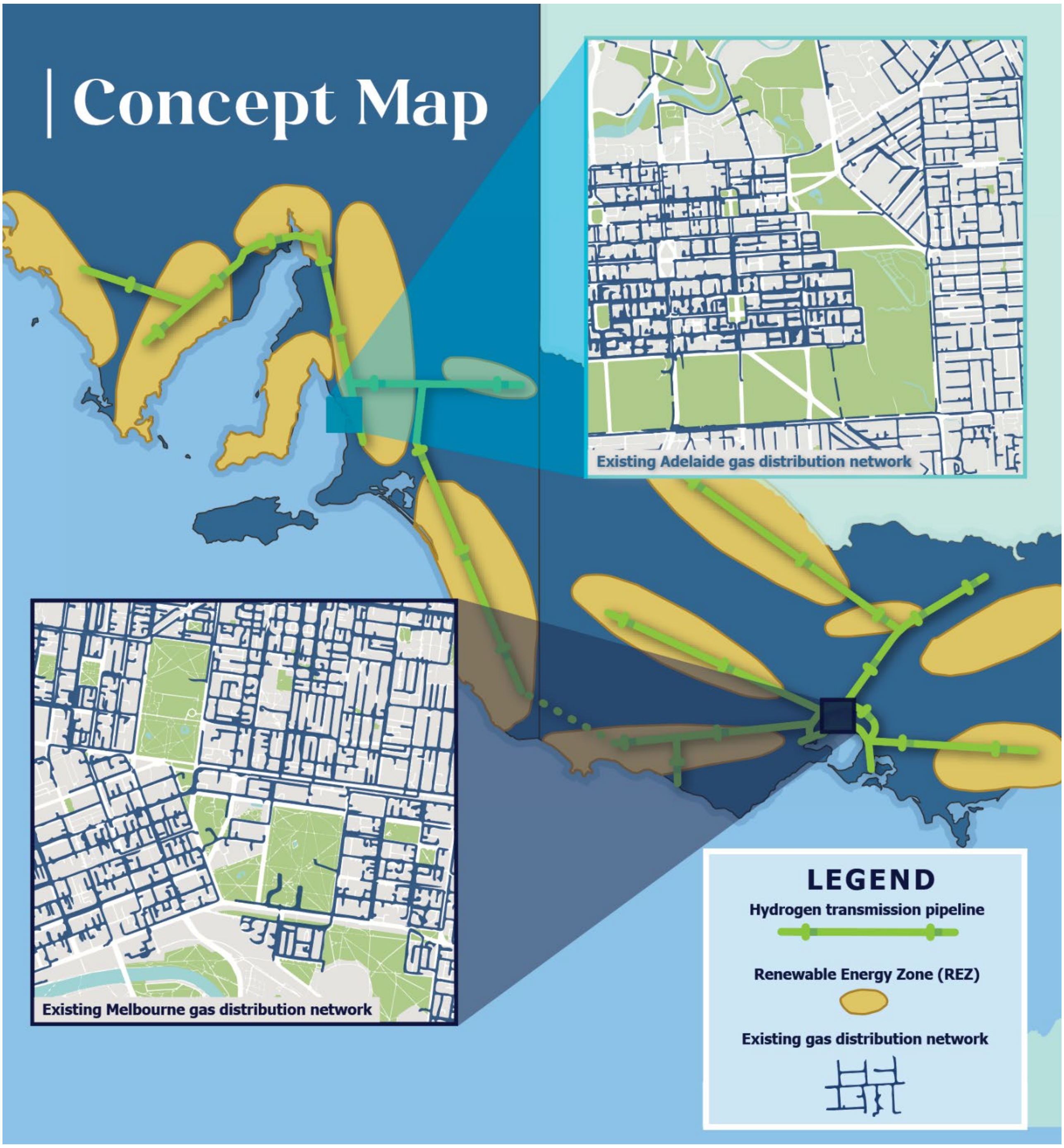
Figure 1: Proposed hydrogen energy supply chain



While this pathway is the focus of this Study, noteworthy limits to this model include that it:

- Investigates dedicated renewable hydrogen production for converting gas distribution networks to hydrogen. In reality, hydrogen could be produced for various end-uses that could also supply into networks as an additional market as part of a ‘hydrogen hubs’ model;
- Only considers hydrogen produced from electrolysis with renewable electricity. Other forms of renewable and carbon neutral gases, such as biomethane or hydrogen coupled with carbon capture and storage, were excluded from this scope.
- Has been produced at a ‘point in time’ primarily throughout 2021/22 and does not consider breakthrough technological advancement and research.

Further, the AHC does not provide a scenario analysis of pathways and associated costings to decarbonise energy consumption of South Australia and Victoria’s wider energy systems encompassing electricity, transport, agriculture, and other relevant sectors. Noteworthy reports considering alternative pathways to decarbonising gas supply are summarised in Chapter 9.3 of this Study.



As part of the 100% hydrogen scenario, renewable hydrogen could be produced through electrolysis in REZ and transported to demand centres in new hydrogen transmission pipelines.

These pipelines will connect to existing gas distribution networks which, with minor modifications, supply renewable hydrogen to homes, businesses, and industry.

Table of Contents

Table of Figures

1. Introduction

The Australian Hydrogen Centre (AHC) is a joint initiative established at the end of 2019 with funding from the Australian Renewable Energy Agency (ARENA) to investigate the technical feasibility of supplying hydrogen through existing gas distribution networks. Its members are:

- The State of South Australia, as represented by the Department for Energy and Mining;
- The State of Victoria, as represented by the Department of Energy, Environment and Climate Action
- AusNet Transmission Group Pty Ltd and AusNet Gas Services Pty Ltd. (AusNet);
- Australian Gas Networks Ltd (AGN), part of Australian Gas Infrastructure Group (AGIG);
- ENGIE Services – Hydrogen Business Unit (ENGIE); and
- Neoen Australia Pty Ltd. (Neoen).

The AHC's overall program of work involves the delivery of key feasibility studies as well as knowledge sharing reports.

Regional Towns Feasibility Studies

Detailed feasibility studies that determine how 10% hydrogen might be delivered into the gas distribution networks of selected regional towns in South Australia and Victoria.

State-Wide 10% Hydrogen Studies

Feasibility studies that determine how the South Australian and Victorian gas distribution networks might deliver 10% renewable hydrogen.

State-Wide 100% Hydrogen Studies

Feasibility studies that determine how the South Australian and Victorian gas distribution networks might deliver 100% renewable hydrogen.

Hydrogen Park South Australia (HyP SA) Knowledge Sharing Reports

Presenting key learnings from HyP SA where renewable hydrogen has been blended into the gas networks in the suburb of Mitchell Park, Adelaide since May 2021.

Each study and the subsequent reports have been developed with support from several independent consultants selected in a competitive process by a Governance Committee of representatives from AHC Members.

2. Natural Gas Demand

In 2020, the South Australian gas distribution network supplied over 460,000 connections with natural gas. This Chapter outlines the segmentation of those customers and considers the key industrial users of natural gas connected to the distribution network in South Australia. This is an important input into the following chapters as it defines how much renewable hydrogen production could be required (Chapter 3) as well as the sectors (and appliances) in which this hydrogen needs to be used (Chapter 5).

As well as analysing the current gas usage of all customers, this Chapter draws on data from the Australian Energy Market Operator (AEMO) to outline gas consumption forecasts in South Australia. It explains the trends that influence gas consumption, including seasonal changes, which are a major factor in South Australia.

This Study assumes that existing natural gas demand is interchangeable with demand for hydrogen and adopts AEMO's Central Scenario as outlined in its 2021 Gas Statement of Opportunities (GSOO) as the basis of forecasts for hydrogen demand through to 2050. To achieve 10% hydrogen in networks for this level of demand, South Australia would need to produce around 5,150 tonnes of hydrogen annually.

Since this Study commenced AEMO has produced subsequent GSOO's reflecting the impact of international conflicts, inflation, COVID-19 and other market uncertainties that have triggered a wide range of plausible futures for gas demand. For this reason, the opportunity to update this analysis frequently could be considered.

Key findings

1. The South Australian gas distribution network supplies more than 460,000 connections across a broad range of applications including industrial (46% of demand), residential (38%), and commercial (16%).
2. This Study assumes that the overall demand for natural gas in distribution networks could be supplanted by a volume of 10% hydrogen.
3. There are a wide range of plausible futures for gas demand. AEMO's Central Scenario as outlined in its 2021 GSOO has been selected as the basis of forecast for hydrogen demand by 2050.

2.1. Current Gas Consumption

In 2020, the South Australian gas distribution network supplied more than 460,000 customers with approximately 20,000 TJ of natural gas.

There are three key customer segments in South Australia:

1. **Residential** – customers who use gas for residential purposes;
2. **Commercial** – business customers who use less than 10 TJ of natural gas each year; and
3. **Industrial** – large industrial customers who consume more than 10 TJ of natural gas per year.

Table 1 provides a breakdown of customer numbers and demand by customer segment.

Table 1: Customer numbers and demand

	Customer numbers (as of 30 June 2020)		Demand (TJ/year ending 30 June 2020)	
	Numbers	**%**	**Numbers**	**%**
Residential	449,649	98%	7,646	38%
Commercial	11,287	2%	3,292	16%
Industrial	112	0.02%	9,247	46%
Total	**461,048**	**100%**	**20,185**	**100%**

Residential gas customers in South Australia make up around 58% of households in the state and typically use 17 GJ of natural gas each year[3]. Households connected to the network generally use gas for cooking and hot water, with some households also using gas for heating given the relatively cool climate in South Australia.

Industry is the highest consumer of natural gas in South Australia, owing to the significant presence of diverse industries that are a key driver of the South Australian economy. As shown in Table 1, there are 112 industrial customers connected to the South Australian gas distribution network in 2020. These customers represent 0.02% of South Australian connections yet account for approximately 46% of total gas delivered through the network.

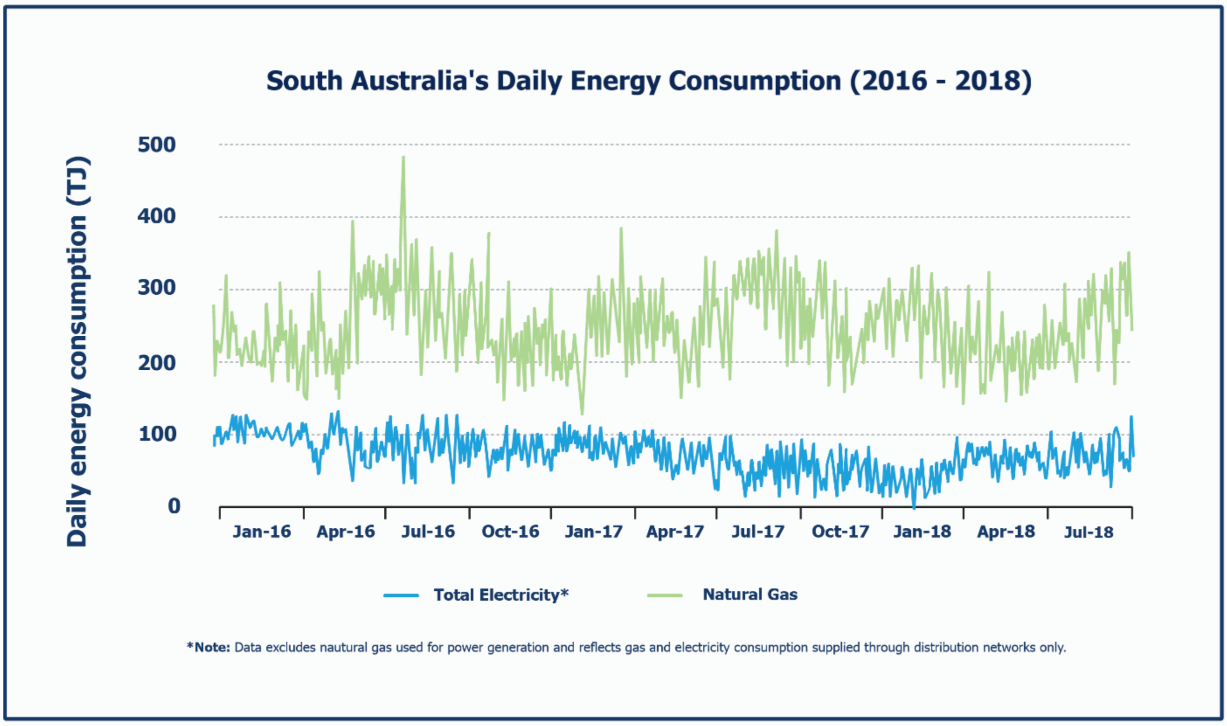
Commercial businesses (comprising offices, hospitals, restaurants, hotels, pools, schools, tertiary education buildings and public buildings) account for 16% of demand and typically use natural gas for cooking, heating, and hot water.

The AHC carried out a desktop analysis study to understand the suitability of South Australian major gas users to accept 10% or 100% hydrogen, with more detailed analysis provided in the *AHC's 100% Hydrogen Distribution Networks Study – South Australia.*

South Australia experiences demand peaks with a natural gas load differential of 2:1 between winter and summer, driven primarily by increased need for residential and commercial heat in colder periods of the year. This is evident in Figure 2 below in the peaks in demand in July 2016, 2017, and 2018.

3 ABS, 2016 Census QuickStats, <https://www.abs.gov.au/websitedbs/D3310114.nsf/Home/2016%20QuickStats>

Figure 2: South Australia's daily energy consumption (2016-2018)



2.2. Forecast Gas Consumption

Determining a conservative forecast for natural gas demand, and therefore for hydrogen demand, was important to guide the analysis in the subsequent chapters. This Study adopts AEMO's Central Scenario to determine forecast gas consumptions for South Australia through to 2050, shown in Figure 3. This reflects the high-level assumption made throughout this Study that all existing uses of natural gas can be supplanted with a volume of 10% hydrogen in natural gas.

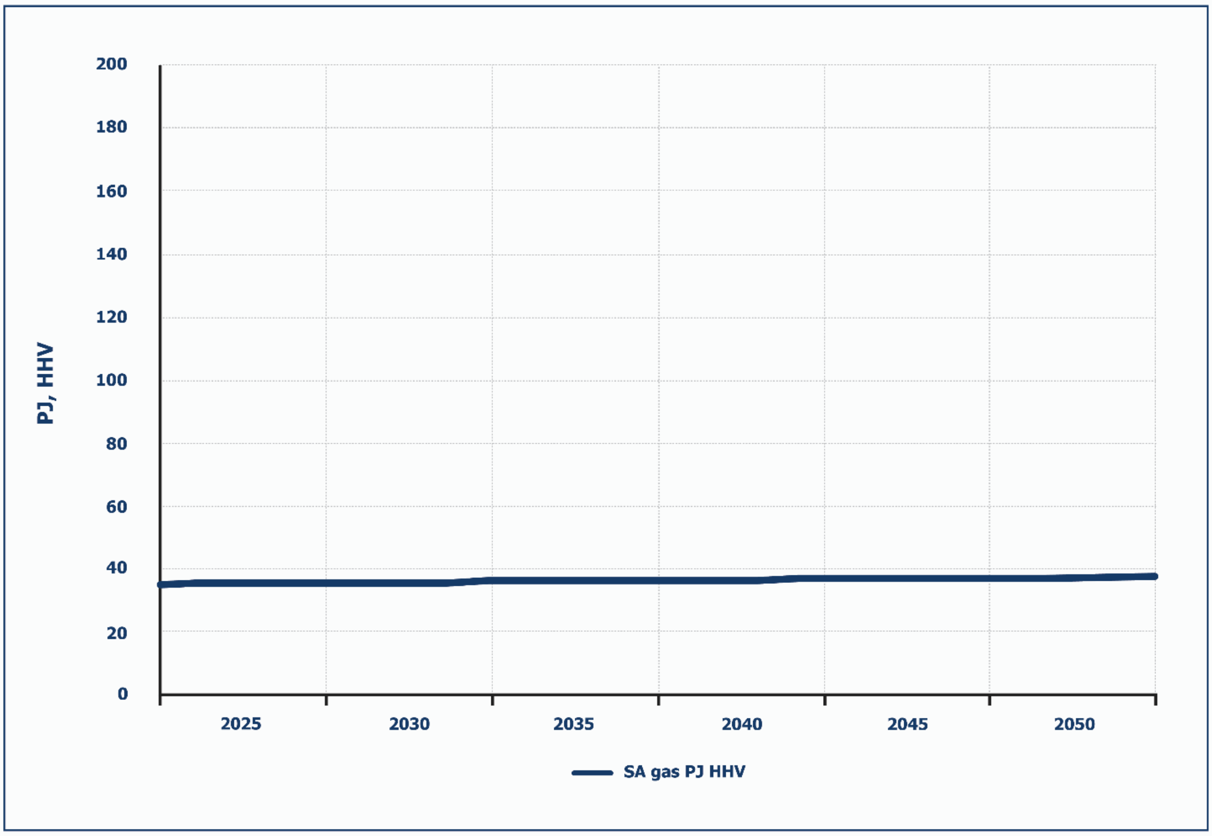
AEMO's 2021 GSOO[4] uses gas data from producers regarding reserves and predicted production to forecast supply and demand measures as well as causes for a set of plausible scenarios. AEMO models three different forecast scenarios, "Slow change", "Central" and "Low gas price", which are based on a range of assumptions about the future evolution of energy use in Australia:

- **Slow change**: Explores reduced gas demand due to slowing economic activity and higher gas prices;
- **Central:** Uses AEMO's best view of future uncertainties; and
- **Low gas price (sensitivity):** Explores potential impacts of lower gas prices on consumption by residential, commercial, and large industrial customer/s, and gas-powered generation.

4 The AHC is aware that AEMO's annual update of the GSOO has been released for 2022 since the drafting of this Report, projecting several scenarios showing higher and lower demand than in the 2021 GSOO Central Scenario. These scenarios reflect the uncertainty in Australia's energy market, for which the 2021 Central Scenario presents a conservative view.

The Central Scenario, as AEMO's conservative view of future potential scenarios, was considered the most appropriate demand forecast for the purpose of this Study.

Figure 3: South Australian gas consumption forecasts (2021 Central Scenario)



Since this Study commenced AEMO has produced subsequent GSOO's reflecting the impact of international conflicts, inflation, COVID-19 and other market uncertainties that have triggered a wide range of plausible futures for gas demand. For this reason, the opportunity to update this analysis frequently could be considered.

3. Renewable Hydrogen Supply, Storage and Transport

This Chapter reviews the key supply chain components needed to deliver the volume required for 10% hydrogen in networks. Natural gas loads for gas power and large industrial gas loads directly connected to the natural gas transmission network were excluded from this study.

This analysis considers the hydrogen supply chain from production, storage and transport to the "gate station" between transmission and distribution pipeline systems[5]. It specifically considers:

- electrolyser requirements;
- electricity requirements;
- water options;
- storage requirements; and
- transmission requirements.

It found that, to optimally deliver 10% hydrogen in networks, the following steps would be required:

Key findings

1. Small scale hydrogen developments could commence the roll-out of hydrogen facilities, with gate stations eventually served by an electrolyser to achieve an aggregate electrolyser nameplate of 90 MW to achieve 10% across South Australia.
2. These systems could be supplied with renewable electricity by Power Purchasing Agreements (PPAs) through the existing electricity network from renewable generation connected to the National Electricity Market (NEM).
3. This could increase the electricity load in South Australia by around 2% on current levels, representing an additional market for solar and wind that is optimised for efficient utilisation.
4. Production facilities could be supplied with small quantities of town or recycled water, to a total of around 100 ML of water annually. This equates to about 0.22% of total annual physical water use in South Australia.
5. Electrolyser water requirements could be provided with water sources not currently utilised by communities. The water would be treated to enable it to be utilised in the electrolysers.
6. Short-term hydrogen storage could enable the electricity load for hydrogen production to be shifted to times of day when electricity demand and prices are low.

5 Gate stations – which can also be referred to as injection points, City Gates, or custody transfer stations – are the gas transfer points between the gas transmission and distribution systems.

3.1. Hydrogen Production and Electricity Supply

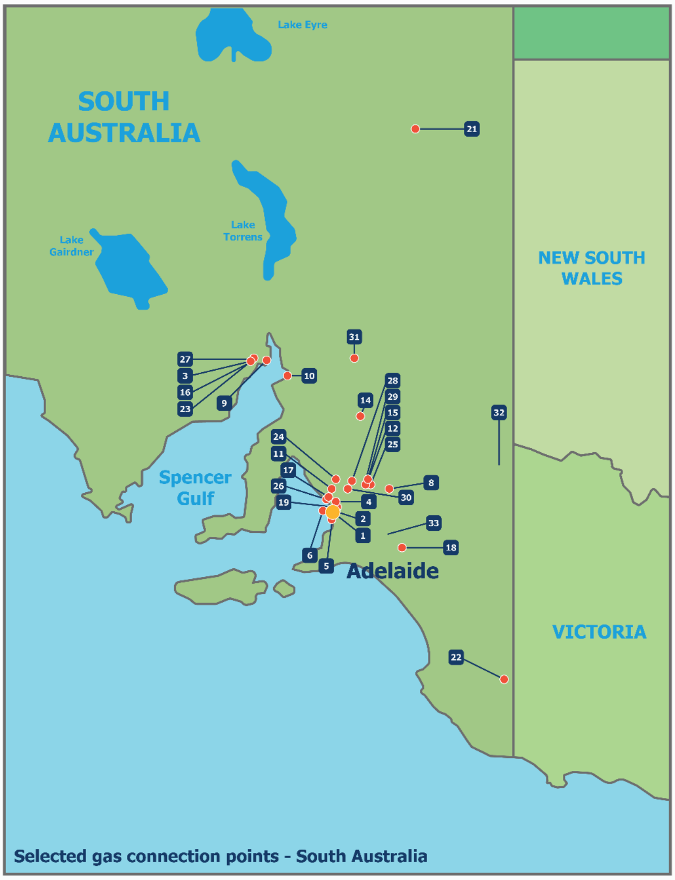
This Section highlights the optimal configuration of hydrogen production facilities in South Australia to achieve 10% hydrogen.

Section 3.3 notes that required short-term hydrogen storage could likely also be distributed at gate stations. Co-locating or integrating these storages with production facilities is likely, avoiding higher costs of transporting hydrogen the distance between its production and storage.

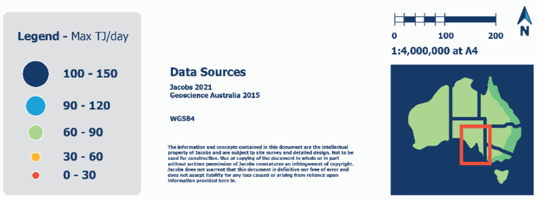
3.1.1. Electrolyser Location, Numbers and Capacity

Research conducted for this Study and detailed in later sections of this Chapter determined that small electrolyser plants located near gate stations and in proximity to demand centres would be suitable to achieve 10% hydrogen. South Australian gate stations are shown in Figure 4.

Figure 4: Selected gas connection points, South Australia



Site Number	Site Detail	Max TJ/day
1	1505018 Gepps X	59.42
2	1505009 Cavan	51.70
3	1505044 Whyalla BHP	20.46
4	1505017 Elizabeth	18.22
5	1505020 Amcor	9.46
6	1505019 Taperoo	12.84
7	1505078 Apcel MS	6.89
8	1505022 Angaston Riverland	6.46
9	Port Bonython	4.54
10	1505038 Port Pirie	3.85
11	1505028 Frost Road	3.32
12	1505021 Angaston ABC	3.26
13	1505079 Mount Gambier MS	2.88
14	1505025 Burra	2.07
15	1505032 Nuriootpa	1.85
16	1505045 Whyalla Cogen	1.39
17	1505042 Virginia	113
18	1505007 Jervois	0.85
19	1505008 Bolivar	0.76
20	1505077 Penola MS	0.71
21	1505024 Beverley	0.68
22	1505006 Naracoorte	0.50
23	1505046 Whyalla Town	0.50
24	1505043 Wasleys Metro Farms	0.36
25	1505023 Angaston Town	0.28
26	1505030 Hi -Tech Hydroponics	0.15
27	1505034 Pacific Salt	0.13
28	1505027 Freeling	0.12
29	1505047 Tanunda	0.11
30	1505040 Sheoak Log	0.10
31	1505036 Peterborough	0.08
32	Berri	Value not given
33	Murrav Bridge	Value not given



Small scale hydrogen developments could commence the roll-out of production facilities near gate stations to enable direct blending into the gas distribution network at distributed points. To achieve 10% across networks, every gate station would be served by an electrolyser to achieve an aggregate electrolyser nameplate of 90 MW.

On the basis that all gate stations are to be served with hydrogen, the aggregate electrolyser nameplate and hydrogen storage volume needed to meet South Australia's hydrogen load requirement in 2030 is shown in Table 2.

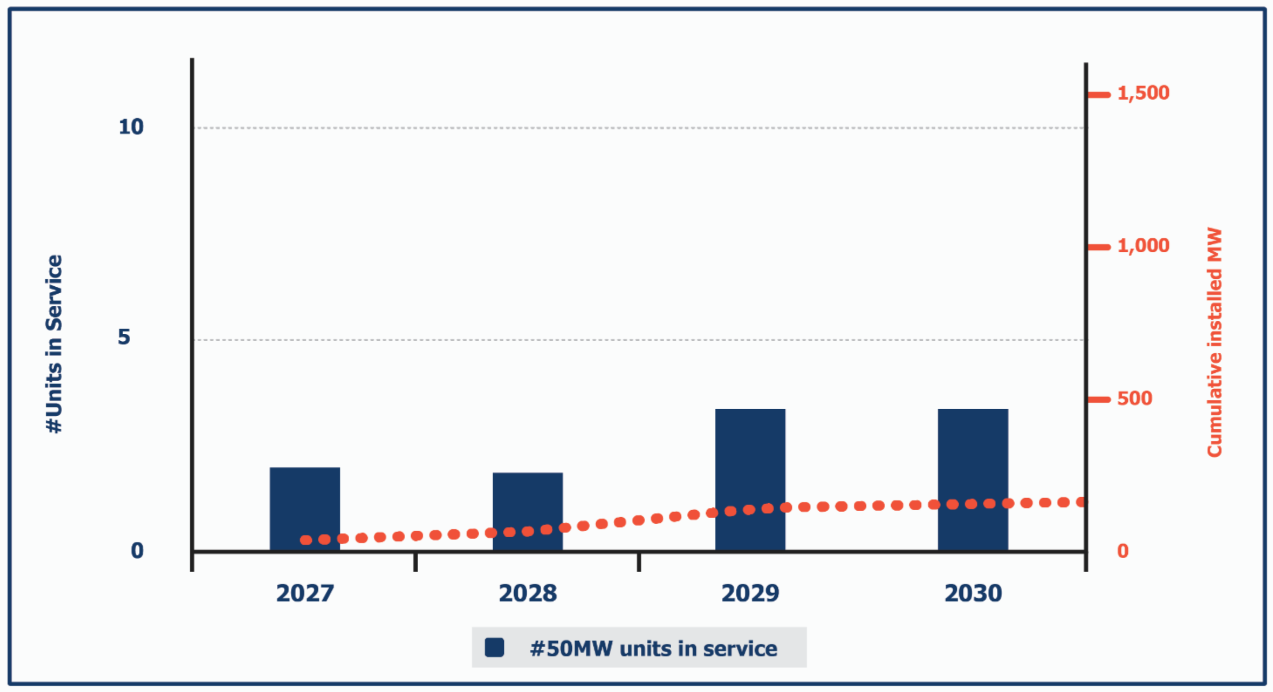
Table 2: Indicative electrolyser configuration for South Australia in 2030

Variable	
Aggregate electrolyser nameplate (MW)	90
Aggregate short-term storage (t)	6
Pipeline sales (t/year)	5,150
Service factor	65%
Load factor	63%
Capacity factor	41%
Total electrical load (GWh)	250

The effective rate of build-out of electrolyser capacity by assumed size of unit required to meet the load through to 2030 is shown in Figure 5.

This rate does not include smaller scale units presently in development. Port Adelaide represents sufficient demand to warrant its own hydrogen production, the feasibility of which is detailed separately in the Regional Towns Study reports. In its case, regional production could mostly cater to industry, such as transport, agriculture, or power generation, where gas distribution networks can be a secondary offtake.

Figure 5: Projected build-out of indicative electrolyser capacity in South Australia



3.1.2. Electricity Requirements

In 2030, electrolysers could be served by the existing electricity network, where up to a 50 MW load would be connected to the sub-transmission electrical system between a terminal station and a Zone Substation at 66 kV or higher.

The electricity load of the hydrogen production facility configuration in Section 3.1.1, and therefore additional renewable electricity generation, is equivalent to roughly 2% of South Australia's current total electricity generation.

The dispersion of production facilities at gate stations means that the electrical load will not require large-scale reconfiguration of the South Australian electricity network or renewable generators.

3.2. Sustainable Water Sourcing

Electrolysis requires water is treated at site to what is commonly referred to as ultra-pure water. Total untreated water requirements for hydrogen production could vary depending on a range of factors including the specific electrolysis technology used, the quality of untreated water, and the need for additional water for indirect production requirements such as cooling.

Water is a precious resource, and existing uses of high-quality already compete for limited sources of ground and surface water. Given hydrogen production requires the purification of any untreated water source regardless of its quality, the "raw" water could be sourced sustainably from lower quality options including sea water, brackish groundwater and recycled wastewater, which would avoid competition with existing demands for higher quality ground and surface water.

Key findings

1. About 100 ML of water could be required annually to supply 10% hydrogen in South Australia's distribution networks, equivalent to around 0.045% of the State's annual water use.
2. Low-quality, underutilised water sources like recycled water would be suitable for hydrogen production and the cost of sourcing and treatment would be insignificant to the overall cost of hydrogen delivered to customers.

3.2.1. Water Requirements

In electrolysis, the basic chemical ratio of water required to produce hydrogen is 9:1. This is generally greater for utility scale electrolysis to account for feedstock and production losses, which was factored in the analysis by assuming a target water consumption ratio of 20L per kg.

On this basis, and with current technology, approximately 5,300 tonnes of hydrogen could need to be produced annually to achieve 10% hydrogen across South Australian distribution networks.

As set out in Table 3, this could require 100 ML of water annually, which is equivalent to 0.045% of annual water usage in South Australia[6].

Table 3: Estimated annual water consumption for hydrogen production in South Australia

10% hydrogen water requirements	
Hydrogen production, tonnes	5,300
Water usage, ML	100

6 SA Water delivers approximately 220 GL of water to South Australian customers each year, <https://www.sawater.com.au/water-and-the-environment/water-in-south-australia/water-in-south-australia>

3.2.2. Sourcing Options

Given the low relative volume of water required for 10% hydrogen and the location of most electrolysers at gate stations in proximity to metropolitan areas, it is likely that water could be sourced from town water (potable water), or more likely recycled water connections.

This would be treated in a similar manner to any other industrial recycled water connection application, with a request made to the relevant local water retailer. This presents an opportunity to grow South Australia's recycled water market and increase its production.

Because existing uses already compete for limited conventional sources, innovative options such as desalinated sea water and recycled water may be suitable opportunities for large-scale hydrogen production.

3.3. Storage Requirements

Short-term storage refers to systems that are suited to cycling (i.e., gas is stored and retrieved) on a daily or even hourly basis. It would fulfill the following key objectives for 10% hydrogen in distribution networks:

- Enabling electrolysers to avoid running in the evening when demand on the NEM is highest. This could be most useful in the future, when significantly more solar generation - occurring in daytime - is added to the system. As a result, electrolysers could run on lower priced electricity, with low, or no electricity network charges;
- Covering short duration changes in loads, so that production facilities are not required to directly 'follow the load' and match output to demand. This is important as line pack in distribution licensed pipelines and distribution pipelines is relatively low with blended gas compared to with natural gas, due to lower maximum operating pressures and the lower volumetric energy density of blended gas; and
- Providing redundancy for hydrogen production facilities to experience short-term outages. This could be especially important in 2030, because production facilities are likely to be separate and distributed rather than connected and centralised as detailed in Section 3.1.

This section covers those benefits to identify the need for short-term hydrogen storage for 10% hydrogen and establish optimal hydrogen storage technologies.

Key findings

1. A small quantity of short-term hydrogen storage could be required to achieve 10% hydrogen in South Australian networks, likely to be in above-ground tanks co-located with production facilities. Progressive developments could provide an aggregate 6 tonnes of short-term storage.
2. Longer-term storage would not be required because the existing natural gas system would continue to provide redundancy and reliability of supply.
3. Locating hydrogen storage close to gate stations (i.e., in proximity to production facilities) could minimise the cost of storing and retrieving gas and is preferable over a centralised system.

3.3.1. Optimal Hydrogen Storage Configuration

To determine the optimal configuration of short-term storage, production facilities were modelled using hourly pool-prices and hourly gas distribution flows from sample gate stations. Analysis found that approximately four hours of storage is optimal to avoid electrolyser operation during periods when the NEM is highly loaded, providing an aggregate amount of 6 tonnes per year.

Cost reductions could be achieved by locating storage in proximity to demand centres, minimising the distance gas would need to travel. This suggests that a distributed system with multiple storages located at different demand centres would be better than a centralised system. The capital cost of the storage technology selected is a lesser concern, given the high rate of utilisation that would be required.

Multiple storage systems were investigated, with above-ground pressurised bullet tanks identified as able to match operational needs given:

- Practical maximum dimensions are 4.5 metres in diameter and 40 meters in length.
- The cost of injecting gas into the bullet tanks is the cost of power required to run the compressors, which would be low compared to the cost of powering electrolysers
- While capital cost of these systems would be high, approximately $1,500/kg of storage capacity, and does not attract economies of scale, the overall unit costs would not be adversely impacted given the high utilisation per year.

3.4. Transmission Requirements

The need for new hydrogen transmission infrastructure can be reduced by adapting existing natural gas infrastructure. Previous sections indicate that hydrogen would likely be blended directly into existing City Gates or the existing natural gas mains for metropolitan Adelaide, meaning that a new hydrogen transmission network would not be required.

3.5. Capital and Operating Cost Estimates

This section describes the assumptions and methodology that were used to model capital costs (capex) and operating costs (opex) for hydrogen production facilities. The following assumptions were made:

- impact of scale economies and learning-rate on capex of more than one production facility when following similar project templates;
- cost reductions caused by a phased approach to building to 10% blended gas;
- costs of connecting to electricity and gas distribution networks based on site locations and network constraints; and
- cost of connecting all facilities to the network to allow for direct blending at several gate stations.

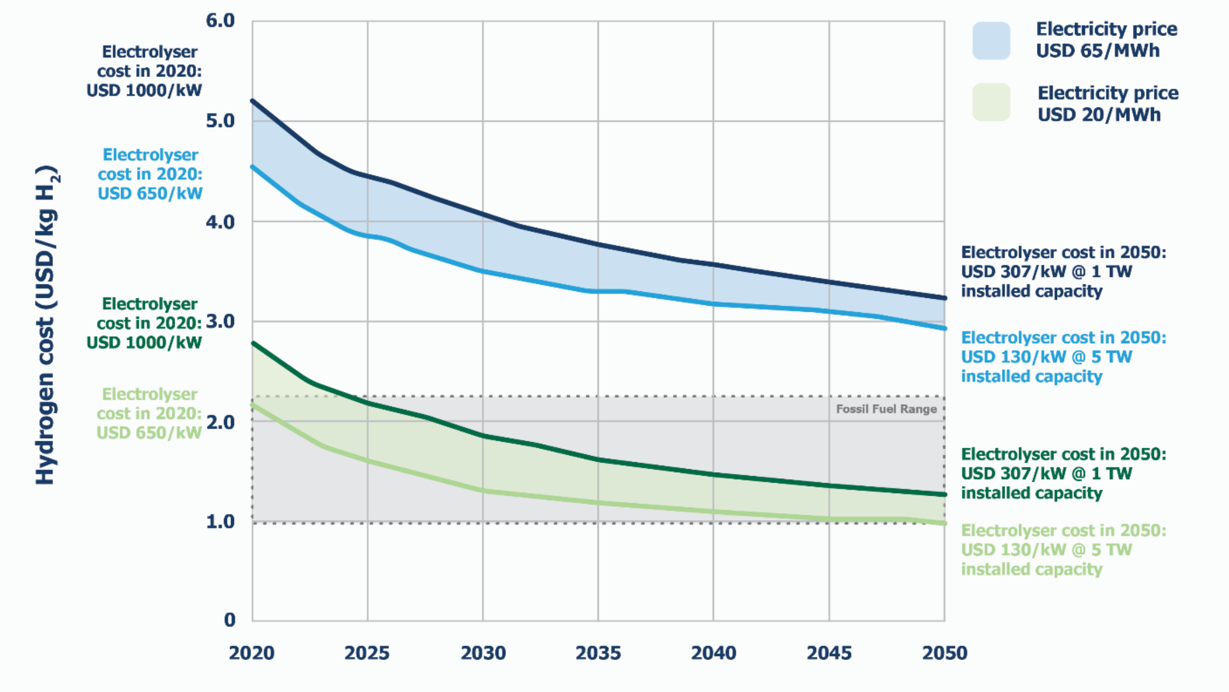
3.5.1. Key Assumptions

Cost and Performance of Future Facilities

To produce modelling that acknowledges factors affecting future cost and performance, a few key sources have been considered.

First, the International Renewable Energy Agency (IRENA) outlook for cost and performance of electrolyser plants from current (2020) to 2050 scale plants, which is summarised in Figure 6.

Figure 6: Cost of renewable hydrogen as a function of electrolyser deployment and electricity price, showing capital cost assumptions



Source: IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi.

Second, real projects under development in Australia were considered which use 10 MW electrolyser plants. These facilities are expected to produce hydrogen at a lower cost than is reflected in the IRENA values by about 20%. This enabled learning rates and scale economies to be estimated for intermediate technology at key scale points – notionally 50 MW at 2030.

Scope of Capital Expenditure

For any production and storage facility, it has been assumed that initial capital costs (capex) comprise of the following:

- Engineering, Procurement & Construction (EPC), or facility construction; and
- Owner's costs.

This capex has been developed on an 'overnight' basis; that is, imagining that a facility could be constructed in a single day.

Facility Construction Costs

The assumed EPC component costs are summarised in Table 4 and will be a direct function of the facility construction costs. They are intended to reflect what a turnkey EPC contractor might offer, and costing should subsequently include the contractor's profit and risk margins.

Scope contingency costs are included such that the resulting estimate is a 50th percentile estimate, which is appropriate for this assessment[7].

Table 4: Facility construction cost components

Cost type	Included/Excluded	Basis
Electrolyser facility costs	• Electrolyser • Power supply • Balance of Plant • Civil works	
Short-term storage costs	• Above-ground bullet storage system and compression of 30 MPa	• Detailed in Section 3.3
Connection costs	• Connection to electricity network • Connection to gas distribution system, including compression and entry • Water connection not included.	• Electrical connected based on the AEMO ISP allowances for connection of solar or wind generators of the same scale[8]. • Water connection not included because these costs are not material relative to other costs.

Owner's Costs

The total cost of a production facility reflects the owner's costs in bringing the facility to a commercial operation condition. Owner's costs are typically estimated on a percentage basis of the direct capital cost. The cost assessment therefore incorporates a reducing percentage through to 2050 to allow for the benefit of repetitive project development, and for how facility size might increase over time.

This assessment also considers costs both before and after Financial Close, and examples of the typical components included in these costs are shown in Table 5.

7 Additional risk contingency to reduce the risk of a cost exceedance to less than 50%, as is usually included in final budget commitment, is not included. All estimates in this Chapter are best-current estimates and therefore should be evaluated at the 50th percentile.

8 AEMO Integrated System Plan draft 2021-22, "Input and Assumptions Workbook".

Table 5: Typical owner's cost elements, before and after Financial Close

Typical costs before Financial Close	Typical costs after Financial close (to commercial operation date)
• Pre-feasibility and concept studies • Feasibility assessments • Land/easements • Consents (e.g., environmental, planning) • Project vehicle formation • Debt sourcing and due diligence • EPC contract specification, tendering, and negotiation • Connection negotiations • Owner's engineering, legal, financial arrangement support • Owner's inhouse costs	• Owner's 'minor items', e.g., fit outs not covered under an EPC contract • Owner's engineering support • Owner's construction period insurance • Initial spares (where not in the EPC cost) • Start-up costs (e.g., recruitment, training, salaries of staff prior to commercial operation, fuels/consumables/electricity/etc used prior to commercial operation) • Owner's inhouse costs • Transaction costs as applicable (interest rate and/or foreign exchange hedging, etc as applicable)

Note: while land/easements are listed, no specific evaluation for associated costs has been included in this assessment.

Scope of Operating Expenditure

Life capital costs, such as controls replacements, or electrolyser stack replacements have been included in operating expenditure.

3.5.2. Cost Assessment

Initial required capex and opex was analysed to understand the impact of costs on the configuration of production and storage facilities. This was completed with consideration of the need for any configuration in the 10% hydrogen scenario to also be utilised in the 100% hydrogen scenario, and therefore does not include end-of-life costs such as decommissioning, and site remediation.

3.5.3. Estimated Capital Expenditure

Capital expenditure (capex) for hydrogen production and storage was estimated using the learning rate, economies of scale and cost elements established earlier in this Section.

Learning rates apply to the electrolyser itself, whereas scale economies apply to both the electrolyser and all other direct cost items other than the connection costs.

This resulted in the capex allowances shown in Table 6, and specific capital cost projections as shown in Table 7 and Figure 7.

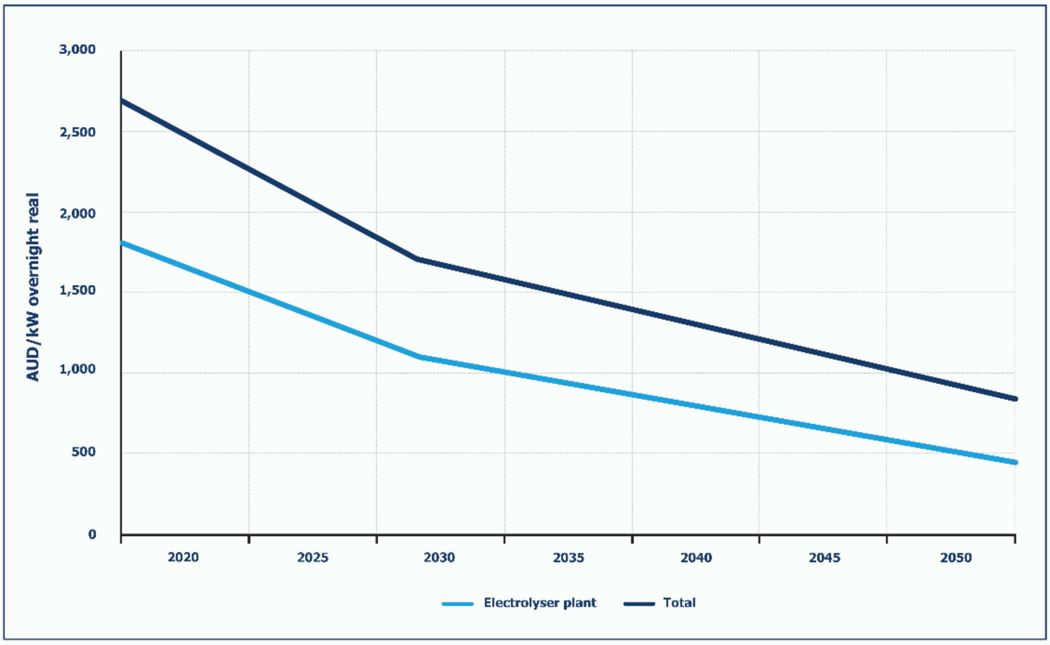
Table 6: Electrolyser capex, AUD-Millions real, overnight

	10 MW (2020)	50 MW (2030)	200 MW (2040	1,000 MW (2050)
Electrolyser	8.57	25.97	73.58	227.01
Power supply	3.43	10.58	29.43	90.81
Balance of Plant (BoP)	6.00	18.51	48.85	150.71
Subtotal (Electrolyser plant)	**18.00**	**55.06**	**151.87**	**468.53**
Short-term storage	1.44	55.42	28.44	142.22
Compressors	3.00	8.98	28.66	88.42
Connection	1.00	5.00	20.00	100.00
Owner's costs	3.52	11.17	22.90	55.94
Total capex	**26.96**	**85.64**	**251.87**	**855.12**

Table 7: Electrolyser specific capex, AUD/kW real, overnight

	10 MW (2020)	50 MW (2030)	200 MW (2040)	1,000 MW (2050)
Electrolyser plant	1,800	1,100	760	470
Total capex	**2,700**	**1,700**	**1,250**	**850**

Figure 7: Specific electrolyser cost projections (AUD/kW real, overnight)



4. Network Readiness

South Australia's gas distribution networks stored and transported about 50% hydrogen in 'town gas' around 50 years ago. This Chapter outlines any augmentation required to support 10% hydrogen. Findings are set out in the following sections:

- capacity of gas distribution networks in Section 4.1;
- hydrogen compatibility of existing pipes and components in Section 4.2;
- network operational processes in Section 4.3; and
- the capital and operating costs of the modifications required for each, in Section 4.4.

Key findings

1. South Australia's gas distribution networks stored and transported about 50% hydrogen in 'town gas' around 50 years ago, so there is strong precedent for hydrogen blended in South Australian gas distribution networks and homes.
2. Gas distribution networks, their components, and constituent materials are compatible to safely and reliably transport 10% hydrogen.
3. Considering the different properties of natural gas and hydrogen including energy density and flow, 10% hydrogen could slightly reduce the networks overall capacity by around 2-4%. The network could absorb this reduction and still maintain supply at historic service levels.
4. Upgrades to network components that enable 10% and 100% hydrogen are expected to be performed under normal preventative maintenance programs at a time when they were normally due for replacement, at a cost of less than the annual operation and maintenance costs for the existing South Australian networks.
5. Safety and operating procedures require minor updates only to transport 10% hydrogen in gas distribution networks.

4.1. Network Capacity

Network capacity refers to the volume of gas that can flow through the gas distribution system. If a distribution network did not have enough capacity to supply the volume of gas required by its customers, there would be interruptions to supply. Factors such as the diameter of pipes, operating pressure, and the volumetric energy density of the gas define the capacity of the network.

Gas distribution businesses have tools and systems in place that enable them to model the capacity utilisation of gas networks as customers gas usage varies over time, or additional customers are added to the network (growth). This ensures any capacity constraints are identified before they impact reliability of supply. These same processes can be used to model the impact of blended hydrogen on network capacity.

To identify any capacity constraints of using hydrogen in South Australia's gas distribution network, three representative sections were modelled with 10% blended gas and 100% hydrogen. This Section presents the findings of the 10% modelling and impacts this would have on augmentation planning for the gas distribution network.

Key findings

1. Considering the different properties of natural gas and hydrogen including energy density and flow, 10% hydrogen could slightly reduce the networks overall capacity by around 2-4%. The network could absorb this reduction and still maintain supply at historic service levels.

4.1.1. Scope

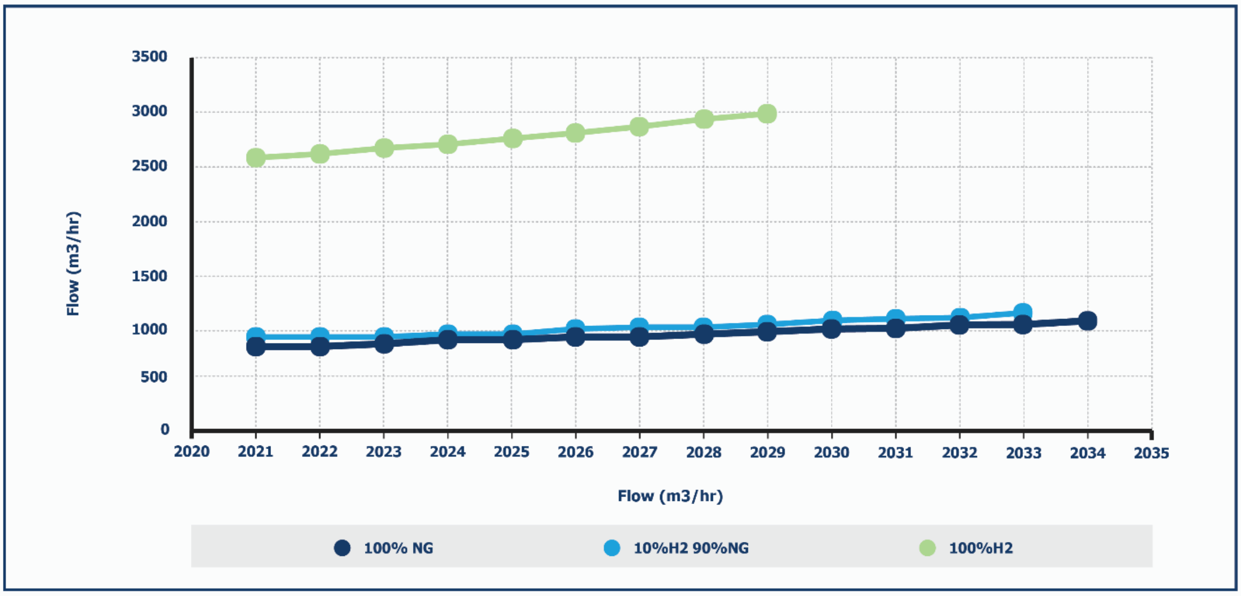
The Yarra Glen gas distribution network in Victoria was selected as a representative network and was assessed to determine impact on capacity of 10% hydrogen. The findings are applicable to South Australia as they follow the same design philosophy. The assessment was made using the following models:

- a baseline model of natural gas, with conservative growth applied for a representative period (i.e., the "control case");
- a blended model (with the same starting point as the baseline model), with the modelled gas changed to natural gas with a blend of 10% hydrogen, with the same growth applied for a representative period; and
- a 100% hydrogen model (with the same starting point as the baseline model), with the same growth applied for a representative period.

Modelling of the Yarra Glen gas distribution network in Figure 8 shows that a minor (approximate 7%) increase in network flow could be required to deliver the same energy to customers with 10% blended gas versus 100% natural gas. This is due to the difference in the higher heating value (HHV) factor between hydrogen and natural gas and is equivalent to an approximate 2% reduction in network capacity.

This reduction in capacity (2%) is less than the increase in flow (7%) would suggest. This is because hydrogen flows through pipes with less friction due to differences in viscosity and density and achieves a much higher flow velocity without a corresponding pressure loss. The flow velocity of 10% blended gas is about 2 m/s more than for natural gas.

Figure 8: Network energy changes over time



This demonstrates that the impact of 10% hydrogen on network capacity is minor, and that no capacity issues are anticipated. The scope of existing network capacity assessment activities should be expanded to consider hydrogen blending to ensure they remain accurate.

4.2. Natural Gas Pipe and Component Compatibility

This Section examines any compatibility issues of existing pipes, jointing materials, and distribution components with 10% hydrogen using mixed qualitative and quantitative methods.

The existing network was designed to convey high-quality natural gas and the interactions of the gas with the material and components used in its construction are well understood. Hydrogen is known to interact with certain material differently to natural gas and impacts that are commonly referred to and were tested with hydrogen in this study include fatigue, embrittlement, and fracture. Understanding these impacts is crucial to determining the feasibility of hydrogen supply in existing distribution networks.

A full compatibility assessment of components and pipes in the South Australian gas distribution network by type, make, and model can be found in Section B1 of the Appendices.

Key findings

1. All distribution piping materials are suitable for use with 10% blended hydrogen.
2. All distribution piping in the South Australian gas distribution system is suitable with 10% blended gas.
3. Most distribution licensed pipelines are suitable for 10% hydrogen, however some require more detailed assessment prior to use.

4.2.1. Overview of Testing Results

4.2.1.1. Distribution Licensed Pipelines, Distribution Piping, and Joint Types

As part of this study, distribution licensed pipelines, distribution piping, and joint types in the existing natural gas distribution system with a Maximum Allowable Operating Pressure (MAOP) below 2,800 kPa were tested for suitability with 10% blended gas. This included piping downstream of gate stations and upstream of customer meter connections.

	Standards for assessment	Results
Distribution licensed pipelines	Pipelines are subject to licensing requirements when the MAOP is greater than 1,050 kPag, and their operations and modifications are mandated to comply with Australian Standard suite *AS(/NZS) 2885 Pipelines – Gas and liquid petroleum.* This standard was not written for pipelines containing hydrogen and is insufficient to determine suitability with hydrogen supply, but its Clause 1.6.2. does apply: *The pipeline is required to comply with the intent of AS 2885.1 and this should be demonstrated through engineering assessment.* Additional guidance for this assessment was provided by the USA design code ASME B31.12 *Hydrogen Piping and Pipelines*, which lists requirements for the design, construction, and installation of hydrogen piping and pipeline systems.	Distribution licensed pipelines were grouped and assessed primarily by pipe design factor, which has a safety margin applied to structural strength to account for uncertainty of the load or structural properties. For pipelines it is defined as the hoop stress at the MAOP divided by the specified minimum yield strength of the material. Pipelines with a design factor greater than 0.4 or MAOP above 2,800 kPa require detailed case-by-case assessment and were not included in the scope of this study. Most of the South Australian distribution licensed pipelines tested were found to be suitable for transporting 10% hydrogen. They have effective resistance to fracture and fatigue at the relevant operating conditions, and the original pipeline hydrotest still provides a margin of safety after hydrogen embrittlement occurs. Of the 89 South Australian pipelines, only 1 required more detailed assessment that was outside the scope of this project for use with 10% blended gas.
Distribution piping	In contrast to the distribution licensed pipelines that were tested, pipes in the distribution network comprise a broader range of materials that operate across four pressure categories. These pipelines fall under AS/NZS 4645.1-2018 *Gas Distribution Networks* which specifies the requirements for safe, reliable, and suitable management of gas distribution networks operating at less than or equal to 1050 kPa. However, this only permits use of hydrogen in blends up to 15%.	Testing found that compatibility differed across the materials used in piping in the distribution networks but was generally acceptable with 10% hydrogen supply. • Steel is acceptable with 10% hydrogen. • Cast iron is acceptable with 10% hydrogen but only at low pressures less than 7 kPa unless further analysis and testing can determine otherwise. • Copper and copper alloys are acceptable with 10% hydrogen. Plastics – polyethylene (PE) and polyvinyl chloride (PVC) – are acceptable with 10% hydrogen.
Joint types	Joint types are covered by the same standards that cover the pipes that the joints are used with.	Testing concluded that all joint types in South Australia's gas distribution network are suitable for use with 10% hydrogen.

4.2.2. Components and Facility Piping

Components in South Australia's gas distribution network were identified in a desktop study using documentation provided by AGN SA. A full compatibility assessment was then conducted and the results for components by type, make, and model, are shown in Section A1 of the Appendix.

4.2.2.1. Metal Components

Testing identified that components with parts made from copper alloys, most aluminium alloys, and stable austenitic stainless steels are suitable for use with 10% hydrogen.

Other metals with poor performance, such as cast irons, high strength carbon steels (i.e., chrome-moly), martensitic stainless steels and nickel alloys, may not be suitable, however these are found within a small number of components.

4.2.2.2. Elastomer and Polymer Component Parts

10% hydrogen is not expected to acutely reduce performance on elastomer and polymer materials. The materials are generally used internally in valves and regulators as seals, gaskets, diaphragms, and occasionally bearing materials.

As a result, replacing the components containing these materials is not considered essential and should instead be resolved through risk assessment of seal leakage and close monitoring of performance rates.

4.2.2.3. Other Components

Specific pressure transmitter makes and models, as well as certain sealants and lubricants, should be assessed for use with 10% hydrogen in consultation with their manufacturers. Additionally, all pipeline repairs going forward should be performed using materials that are compatible with 100% hydrogen. This may also require consultation with manufacturers to determine suitability.

4.2.2.4. Facility Piping

A desktop review of facility piping design codes found that facilities like gate stations and field regulators should account for the requirements of US design code ASME B31.12 *Hydrogen Piping and Pipelines* including increased susceptibility to fatigue, particularly from thermal expansion.

From a review of the AGN Albury-Wodonga network, it is expected that most field regulators would not require modification, because they apply a common layout that is well-designed to minimise expansion stress. For some connections, however – typically industrial connections with above-ground regulator stations – there is a greater likelihood that modification of pipe supports may be required. It is expected that a requirement to conduct non-destructive testing of piping welds would be a rare outcome of analysis.

4.2.3. Outcomes

This compatibility review of South Australia's gas distribution network identified that the vast majority of piping and components are compatible with blended gas and only a small number of components would need to be replaced. The total cost of replacing these components has been estimated and found to be within the limits of regulated gas distribution network repair and maintenance. Detailed cost estimates can be found in Section B1 of the Appendices.

4.3. Operational Considerations

Existing systems and documentation in the gas distribution industry are designed for specific operating conditions, characterized by the pressure, temperature, flow rate and direction, and composition of natural gas.

Introducing hydrogen into South Australia's gas distribution network requires updates to operational and safety procedures to recognise the change in supply. Two main categories were considered to determine what considerations should be made:

1. those relating to the design of the system for safe operation. These are the types of issues that could be identified through a Hazard and Operability Study (HAZOP).
2. those relating to how the system is operated, including any activities undertaken by operators, such as preventative maintenance and leak detection.

This Section first considers the chemical properties of hydrogen that would be different to existing network operations, before summarising the actions that should be taken for converted networks to operate safely.

Key findings

1. Existing systems and documentation in the gas distribution industry are designed for specific operating conditions, characterized by the pressure, temperature, flow rate and direction, and composition of natural gas.
2. The different characteristics of hydrogen to natural gas should be reflected in an update to safety and operating procedures and systems.
3. The required changes to safety and operating procedures and systems would not impede the feasibility of achieving 10% hydrogen.

4.3.1. Comparative Evaluation of Chemical Properties of Hydrogen and Natural Gas

The properties of hydrogen and natural gas vary, and the purpose of this Section is to summarise a comparative review of properties that require operational considerations for gas supply. Because the composition of natural gas is not the same, methane was used as a proxy in testing to explain differences in chemical properties.

4.3.1.1. Density and Viscosity

The first prominent variances are the density and viscosity of the fluid gasses, defined below and shown in Table 8 below.

- **Density** is a measure of how compact the mass of a material is per unit of volume.
- **Viscosity** is a measure of a fluid's resistance to flow.

The density and viscosity of hydrogen are lower than methane and it has different flow-properties as a result. These flow properties cause it to leak faster and disperse more rapidly. These behaviours are also increased because hydrogen is more buoyant in air. For related reasons, pressure waves carry more rapidly through hydrogen.

Table 8: Properties of hydrogen compared to methane

Property	Methane	Hydrogen	Units	% change (H_2 / CH_4)
Molecular weight	16.06	2.016	Kg/kmol	13%
Density	0.72	0.09	Kg/Nm^3	3%
Heating value	55.6	142	MJ/kg	255%
	893	286	MJ/kmol	32%
	40	12.7	MJ/ Nm^3	32%
Approximate viscosity	11.3	9	µPa.s	80% approx.
Speed of sound	446	1,270	m/s	285%
Ratio of specific heats	1.306	1.406	-	108%

Note: The values listed in this table are approximate for 'normal' pressure and temperature conditions: 20°C, 1bar.

4.3.1.2. Flammability

The next prominent difference is between the flammability characteristics of the gasses[9]. Flammability comprises of many characteristics, and the those that are useful for this study are compared in Table 9.

9 The properties quoted come from a variety of sources; there is some minor discrepancy between sources for these values depending on how they are defined and measured, so other references may differ.

Table 9: Comparison of flammability characteristics of hydrogen and methane

Aspect	Definition	Methane	Hydrogen	Outcome
Minimum ignition energy (mJ)	A measure of the sensitivity of an explosive substance to ignition by electrical spark in certain conditions.	0.25	0.017	The energy required to ignite hydrogen is lower than methane, presenting greater risk of ignition.
Auto-ignition temperature (°C)	The lowest temperature in which a material spontaneously ignites under a certain pressure.	500	580	The temperature required for hydrogen to auto-ignite is lower than for methane, presenting greater risk of auto-ignition.
Hazardous area (HA)	An area in which an explosive atmosphere is present, or may be expected to be present, in quantities as to require special precautions for the construction, installation, and use of equipment[10].	-	-	Many work environments contain or produce explosive atmospheres. The lower explosive limit of hydrogen means the explosive atmosphere it can form in work environments with the same conditions is generally larger than methane.
Explosive limits	The range of concentrations of a material in air that will burn or explode with ignition at a certain pressure.	Lower: 4% Upper: 17%	Lower limit: 5% Upper: 75%	
Explosive atmosphere (hazardous area)	A mixture of explosive materials in air meeting certain conditions that will completely combust after ignition.	Generally smaller	Generally larger	
Explosion pressure (MPa)	The changed pressure of an enclosed space caused by explosion of a substance in it.	Generally lower	Generally higher	Experimental data[11] has shown that hydrogen develops a higher explosion pressure than methane across a wide range of concentrations.
Deflagration, Detonation, Detonation range	**Deflagration** is rapid combustion that produces heat, light, and a subsonic pressure wave. **Detonation** is a self-sustaining combustion that produces heat, light, and a supersonic pressure wave. **Detonation range** is the range of concentrations of a substance in air at which detonation can occur.	5.3 – 15.5%[12]	18.3 – 59%[13]	Hydrogen can burn at a broader range of concentrations in air than methane. Although this makes detonation more likely to occur to hydrogen mixtures, the conditions required are specific and would require a large, accumulated leak in an enclosed space. If deflagration takes place in open air in an enclosed space, a mechanical pressure release can mitigate the pressure wave it produces. In contrast, pressure-relief could be ineffective in mitigating the magnitude of pressure wave caused by detonation. The level of potential harm caused by detonation can be estimated using the total leaked inventory and would be best controlled by prevention or separation.

10 AS/NZS 60079.

11 The source of this comparison can be found here: <https://www.nature.com/articles/s41598-021-00722-8.pdf>

12 Detonation range of methane in air supplied by NIOSH Lake Lynn Laboratory studies, which can be found here: <https://www.cdc.gov/niosh/mining%5C/UserFiles/works/pdfs/madea.pdf>

13 Detonation range of hydrogen in air supplied by US Office of Energy Efficiency and Renewable Energy, which can be found here: <https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/h2_safety_fsheet.pdf>

4.3.2. Summary of Updates Required to Operational Procedures

Current operating processes were tested against hydrogen's properties listed in Section 4.3.1 to determine any updates that might be required for natural gas distribution networks to safely transport hydrogen.

It was found that this could take place within current safety and operating procedures. Some potential considerations are detailed in Section A2 of the Appendix, but these are not unlikely to present concerns or major step changes to current procedures.

4.4. Capital Replacement Cost Estimates

Considering the analysis in previous sections of this Chapter, capital costs have been estimated for the following aspects of the hydrogen transition:

- Replacement of components made with hydrogen-incompatible or unknown materials.
- Replacement of hazardous area rated electrical equipment
- Assessment of excluded pipelines.

Importantly, much of the capital works required for 10% hydrogen in networks ensure that the networks are future-proofed for 100% hydrogen.

Further, while these costs have been estimated, it is expected that these changes could be performed under normal preventative maintenance programs at a time when they were normally due for replacement so there is minimal incremental cost to prepare the networks for hydrogen.

The total costs for the replacement of these components would approximately be $58.6 million for components and $6.3 million for electrical control systems.

These costings are considered 'worst case' as replacement is costed where further investigation may determine that it is not required. For context, the networks in South Australia spend on average around $180 million per annum combined on operational expenses and capital upgrades. Therefore, these costings indicate that the estimated total upgrade costs are less than the annual operation and maintenance costs.

4.4.1. Replacement of Components made with Hydrogen-Incompatible or Unknown Materials

Section 4.2 discussed replacement, risk assessment, or further investigation for several components containing materials that are not suitable for hydrogen service.

Costs for replacement of these incompatible components has been estimated to be approximately $58.6 million. A breakdown of these cost estimates is provided in Section A3 of the Appendix.

4.4.2. Replacement of Hazardous Area Rated Electrical Equipment

Hydrogen as a process fluid can change the Hazardous Area (HA) compliance of electrical equipment due to a change of both Gas Group and Temperature Class. Hydrogen requires additional safeguards compared with natural gas.

At Gate Station, Field Regulator and Customer Meter Set facilities, the following instrument types require upgrades:

- flow / volume correctors;
- limit switches;
- junction boxes;
- temperature transmitters;
- solenoids; and
- isolator switch.

For the purpose of this study, the Section displays the most conservative scenario 'Scenario 3' by costing the replacement of all instruments as summarised in Table 10.

The cost breakdown for all three scenarios can be found in Section A3 of the Appendix. Costings allocate time for engineering and include:

- Creation of datasheets for new Hazardous Area equipment.
- Design/Review for new junction box(es).
- Installation Scope(s) of Work for all sites with equipment installations.
- Cable Calculations / Review for new relocated distribution board locations.
- Review / Selection of new relocated Remote Telemetry Unit and distribution board locations. All the new (replacement) instrumentation pricing has been based on equipment that is compliant for gas group IIC, temperature class T1 and are appropriate for use in the indicated zone identified in the provided information.

Estimates are based upon the AGN SA network, comprising 3 "City Gate" sites, 257 "Field Regulator" sites and 253 "Customer Meter Set" sites in South Australia.

Table 10: Scenario 3 cost breakdown for replacement of hazardous area equipment, AGN SA

Scenario	Equipment & Materials	Installation Cost	Engineering and Owner's Cost	Uncertainty/ Contingency	Total cost
Scenario 3	**$2,750,845**	**$1,560,600**	**$991,632**	**$954,554**	**$6,257,631**

4.4.3. Assessment of Excluded Licensed Distribution Pipelines

Several distribution licensed transmission pipelines with MAOP above 2800 kPag or high design factor, as listed in Section A3 of the Appendix, were excluded from the assessment in this project. High pressure and high design factor pipe require a more detailed review on a case-by-case basis.

Methods of assessment recommended for each pipeline are discussed in Section A3 of the Appendix, along with the estimated costs to perform these assessments and the cost per network.

Costs for in-line inspection (ILI) of pipelines have not been included but may be recommended in practice.

5. Existing Customer Appliances

The appliances sold in Australia are designed to operate efficiently and effectively with natural gas as defined by Australian Standard AS 4564:2020.

They are tested with varying gas compositions to account for the varying sources of natural gas supplied around Australia. One such "limit" gas contains 13% hydrogen, and therefore most certified household gas appliances sold in Australia have undergone a range of safety tests with this level of hydrogen.

Work is ongoing in Australia and internationally to further understand the impacts of different compositions of hydrogen in natural gas 'downstream' of the gas meter (i.e. to customers), including what reasonable upper limits for blends can be applied uniformly across networks without requiring modification to end-uses.

This work is primarily led in Australia by the Future Fuels Cooperative Research Centre (Future Fuels CRC) which has established a dedicated program investigating the compatibility of end user equipment with future fuels that is overseen by a panel of government regulatory bodies and appliance industry experts.

Key findings

1. The majority of domestic appliances are compatible with volumes of at least 10% hydrogen in natural gas, with work underway to determine the maximum upper limit.
2. Research to confirm Type B appliance compatibility is well progressed, alongside the implementation of several demonstration projects.
3. There is significant expertise that exists in Australia's appliance sector and internationally that can be effectively leveraged to achieve streamlined approvals and scaled implementation.

5.1. Key Terms

Gas distribution networks deliver gas to a wide range of customers who use the gas to operate an even wider array of gas appliances. Appliances supplied by gas distribution networks in Australia are typically classified into one of two different categories[14]:

- "Type A" appliances; or
- "Type B" appliances.

Type A appliances are domestic and light commercial type appliances, such as cookers, space heaters, central heaters, water heaters, catering equipment, and leisure appliances. There are approximately 11 million Type A appliances in Australia, subject to a bulk certification scheme where a specific set of tests are performed on example appliances to certify that they are fit for use.

14 A more detailed description of Type A and Type B appliances is available in the AHC's 100% Hydrogen Distribution Networks Study – South Australia

Type B appliances are generally used in industrial and commercial applications such as large boilers, furnaces, kilns, and commercial ovens. Their gas consumption is greater than 10 megajoules per hour (MJ/h) and are individually certified prior to commissioning.

The primary consideration for compatibility of an appliance with any fuel gas mixture, are the gas quality characteristics of the fuel gas mixture, and the subsequent combustion characteristics of the fuel gas. The gas quality characteristics for "General Purpose Natural Gas", which covers the range of gases typically delivered to the South Australian customer in gas distribution networks, are defined by Australian Standard AS 4564:2020.

5.2. Type A Appliances

The Future Fuels CRC has initiated several research projects to investigate the impacts of a 10% hydrogen blend in natural gas on Type A appliances in Australia. While work is still ongoing in this area, findings from the research so far are that a 10% hydrogen blend with natural gas can be used safely in Type A appliances. These results are in line with Type A appliance testing carried out in other Australian and overseas jurisdictions.

Future Fuels CRC research programs completed and currently underway are summarised below[15]:

Project	Title	Date Range	Summary
RP1.4-01, RP1.4-01A, RP1.4-01B,	Type A appliances Test Program	Feb 2019 to May 2020	Investigated the performance of 26 different domestic and commercial Type A appliances operating on hydrogen blended natural gas. Concluding that the majority of appliances will work safely and reliably with hydrogen blends of 10%.
RP1.4-05	Performance of Type A appliances with blends of hydrogen and natural gas	February 2021 to September 2024	The key outcomes of this project will include: - A recommendation on a maximum hydrogen percentage that can be tolerated in blends with no changes to equipment – considering most types of Type A appliance. - Information on whether minor changes to some equipment will increase the allowable maximum percentage hydrogen in a blend. - Documentation on a small trial of legacy appliances with hydrogen blends - Further information on cooker light-under, operation of domestic gas appliances and 100% hydrogen appliances

The current body of research suggests that Type A appliances are able to operate with at least 10% hydrogen in their fuel supply, with work underway to determine compatibility with higher percentage volumes.

15 Compatibility of end user equipment with future fuels (RP1.4) Archives - Future Fuels CRC

5.3. Type B Appliance Assessment

Type B appliances are typically industrial and are generally not mass manufactured; these are usually made in small volume production runs, or custom-made to suit a specific process. Because of this, each Type B appliance installed in Australia must be individually assessed to ensure it is fit for use, then registered/certified by state based technical safety regulators before being commissioned for use by the end consumer.

Type B appliances can be grouped into several broad categories according to commonalities in design of burners and other componentry. Assessment of each category of Type B appliance is a multi-faceted consideration, considering the suitability of the constituent parts, the quality of the installation, how the system performs as a whole to achieve the desired outcome, and what adjustments or modifications can be performed to improve performance and/or safety.

Due to the variation in Type B appliance designs and uses, and the limited operating experience using hydrogen containing fuels across the Type B appliance population typically connected to gas distribution networks, blanket conclusions on Type B appliance compatibility with hydrogen blends are unable to be reached at this time. Future Fuels CRC research programs completed and currently underway are summarised below[16]:

Project	Title	Date Range	Summary
RP1.4-02	Type B appliances and Industrial equipment	Jun 2019 to Jan 2020	Reports on the range, tolerances and maximum levels of hydrogen that can be blended into natural gas for Type B appliances and provide a basis for future work on developing equipment compatible with high levels of H2 in natural and 100% hydrogen.
RP1.4-03	Pathways for hydrogen adaptation to industrial processes	5 Jul 2020 to 15 Sep 2023	The project generates unique and new insights on the effect of blending hydrogen into industrial burner operating on natural gas. Quantifying the effects on flame characteristics and the adaptation strategies required helps pave the way to the introduction of hydrogen fuel to thermal industrial processes. The intention is to make decision-makers aware of the pathway through which the intended outputs of the research will lead to practical changes that impact in the industry.
RP1.4-06	Planning detailed assessment of Type B appliances with blends of hydrogen and natural gas	February 2021 to July 2021	This project provides detailed plans for experimental and engineering approaches to: • cost-effectively identify any compatibility issues of commercial and industrial appliances and burners (Type B) with hydrogen / natural gas blends and • determine upper limits for blending of hydrogen into natural gas.

16 Compatibility of end user equipment with future fuels (RP1.4) Archives - Future Fuels CRC

Project	Title	Date Range	Summary
			The project delivers a report detailing the assessment of options considered; and a costed proposal(s) for the best option(s) to determine the compatibility of a range of Industrial and Type B appliances with 10% hydrogen in natural gas, and the maximum volume of hydrogen for a range of appliances without making any changes to equipment and/or with minor changes.
RP1.4-08	Detailed assessment of Type B appliances with blends of hydrogen and natural gas and 100% hydrogen	1 October 2021 to 30 December 2024	A detailed assessment of Type B appliances with blends of hydrogen and natural gas and 100% hydrogen. The project will provide an understanding of any potential Type B end-user changes required for different blend ratios and 100% hydrogen.
RP1.4-09	Industrial pathways to 100% hydrogen	Jan 2023-Aug 2024	An in-depth review on how current industrial processes can be adapted to hydrogen combustion including an assessment of control system changes and product quality impact. This project will culminate with a full scale industrial trial by converting existing equipment to operate on 100% Hydrogen.

The current body of research suggests that Type B appliances typically connected to gas distribution networks can operate safely and efficiently with at least 10% hydrogen in their fuel supply. Ongoing research will indicate the upper limit of hydrogen blending with existing appliances.

6. Regulatory, Legal and Standards Considerations

This Chapter considers regulation, legislation and standards work underway to support hydrogen delivered via existing gate stations responsible for supplying gas to distribution networks in South Australia, and outlines "low regret" steps that could be taken to enable 100% hydrogen supply in networks.

It is assumed that existing gas supply chain participants and market systems could continue to operate as usual. New hydrogen production supply approvals are covered by existing legislation and licenses, and therefore do not present any barriers to 10% hydrogen.

Key findings:

1. Government Officials have either agreed or significantly progressed reforms to the National Gas Regulatory Framework to enable 10% hydrogen in natural gas in South Australia. These efforts include:
    a. Changes to the definition of 'natural gas' to clarify how it applies to blended gas and confirm that the current consumer protections and economic regulatory regime continue to apply.
    b. Changes to Part 19 of the National Gas Rules (NGR) to ensure there is no barrier preventing the introduction of blended gas into the South Australian distribution system.
    c. Compliance with national and South Australian gas quality specifications and standards to accommodate the different specifications between blended gas and 100% natural gas.
2. 10% hydrogen is compliant with retail gas rules, codes, and licenses, and no material compliance issues are anticipated to arise.
3. Emissions reductions achieved by hydrogen in networks are not recognised under any scheme in South Australia at present. Development of a scheme(s) would incentivise increased demand for hydrogen (and other renewable gases) in networks as an alternative to natural gas.
4. Scheme development could benefit by learning from the success of Australia's renewable electricity sector, which is now considered mature having achieved significant cost reductions over time through a range of policy mechanisms such as the Renewable Energy Target.
5. Providing early certainty by requiring all appliances sold or installed to be hydrogen-ready to facilitate the development of necessary customer uptake, standards updates, planning and skills capabilities to enable a smooth transition from 10% to 100%.

6.1. National Gas Regulatory Framework Reform

Introducing 10% blended gas into the network has triggered regulatory changes in two broad categories:

- Those needed to enable hydrogen to play a role in energy markets and address integration issues; and
- Those that would enable costs of hydrogen production and distribution to be recovered.

These changes are important to enable participants to deploy and demonstrate the viability of hydrogen blending and to address uncertainties associated with the interactions of hydrogen and the national gas regime guided by the National Gas Law (NGL) and the National Gas Rules (NGR).

In October 2022, Energy Ministers agreed a final package of amendments to the national gas regulatory framework to bring biomethane, hydrogen blends and other renewable methane gas blends within its scope. These changes are summarised in Table 11 below:

Table 11: Key issues addressed to achieve 10% hydrogen

Issue(s)	Is 10% blending feasible if the issue(s) are not addressed?	Are the issue(s) being addressed?	What is the proposed timeframe for the required changes?
Hydrogen does not participate in the energy market and is therefore not adequately incorporated within regulatory frameworks	To achieve 10% hydrogen, definitional changes need be made to the NGL and NGR.	Energy Ministers at Commonwealth, State and Territory level have agreed to reform the national gas regulatory framework to bring hydrogen blends within the scope of the regulatory framework.	The changes have been agreed and are expected to be legislated in 2023.
Wholesale market issues, including the connection of hydrogen production facilities to the network	An amendment to Part 19 of NGR would be required to achieve 10% hydrogen.	The AEMC initiated a rule change process for the NGR.	The changes have been agreed and are expected to be legislated in 2023.
Changes to regulations due to different heating value of hydrogen gas	A change to AEMO procedures would be required to achieve 10% hydrogen.	AEMO is developing a change to this approach.	Changes are being considered, AEMO is targeting implementation by early 2024 (prior to any projects coming online)
Introduction of new customer protections for 10% blended gas	Blending could proceed without this change.	AEMC has recommended final rules in relation to customer notifications in relation to a change in the type of gas supplied, pricing, billing arrangements and quality risks.	The changes have been agreed and are expected to be legislated in 2023.

6.2. Gas Quality Standards and Heating Values under National and South Australian Regulatory Requirements

6.2.1. Compliance with Gas Quality Standards and Specifications

Compliance with gas quality specifications and standards is not expected to raise any material regulatory issues.

The *Gas Regulations 2012 (South Australia)* contain gas specifications that require AGN to ensure that all gas distributed by its network complies with the limits in AS 4564, unless otherwise agreed with the Office of the Technical Regulator (OTR).

Similarly, the NGR provides that the gas quality specification for STTM hubs is AS 4564 and any additional gas quality specifications contained in the applicable Access Arrangement[17]. The NGR requires each STTM shipper to ensure that natural gas supplied to a hub complies with this specification unless agreed with the distributor or authorised by law.

It is understood from analysis undertaken for Australia's National Hydrogen Strategy and other reports that a blend of up to 10% hydrogen and natural gas is expected to comply with all the requirements of AS 4564.

However, the application of AS 4564 to any blend of natural gas and hydrogen is unclear due to the definition of 'natural gas' used in AS 4564, and this definition should be clarified. This would require a change by Standards Australia, which is currently considering issues related to hydrogen blending through its Hydrogen Technologies committee and working groups.

Blends of greater than 10% hydrogen for future hydrogen projects would likely require changes to AS 4564, or changes to the Gas Regulations and NGR.

6.2.2. Changes to Heating Values

Blended hydrogen has a lower heating value per unit of volume than natural gas. Small retail gas customers have meters that only measure the flow of gas delivered to the customer. Retail gas is charged based on the energy content (heating value) of the delivered gas, so the metered flow must be converted into megajoules (MJ).

Because blended hydrogen has a lower heating value per unit of volume than natural gas, a change to this calculation would avoid impacted customers facing higher retail bills.

This requirement to change heating values is not expected to require any changes to regulatory instruments. AGN can make this change itself but needs approval from the OTR[18].

ESCOSA's Metering Code and AEMO's Retail Market Procedures (SA) require that AGN calculates heating values in accordance with a methodology approved by the OTR. These requirements are implemented through AGN's Gas Measurement Management Plan (GMMP), which is prepared by AGN under the Metering Code and approved by the OTR.

The Gas Regulations 2012 (South Australia) and AEMO's Retail Market Procedures (South Australia) also impose certain obligations on gas retailers in relation to heating values and pressure correction factors (PCFs).

17 AGN's Access Arrangement does not currently contain any additional gas quality specifications.

18 While our view is that changes are unlikely to be needed, we note that the AEMC is currently considering whether the NGR restricts distributors' ability to calculate heating values in different parts of the distribution system to accommodate the different uses of natural gas equivalent gases in the facilitated markets, including the STTM. See: AEMC, Review into extending the regulatory frameworks to hydrogen and renewable gases, Consultation paper, 21 October 2021, pp. 41-42.

6.2.3. Compliance with Retail Gas Rules, Codes, and Licenses

The ESC's Energy Retail Code of Practice regulates the relationships between retailers, distributors, and customers, and imposes consumer protections for the supply of electricity and gas to small customers.

This Study does not consider that any material compliance issues are likely to arise because of hydrogen blending and does not consider that there are any barriers to 10% hydrogen under these Codes

6.3. Low Regret Options to Support 10% Hydrogen in Networks

Renewable hydrogen is currently more expensive than natural gas. Hydrogen, however is expected to be competitive with natural gas in in the short to medium term depending on the policy settings in place for the industry. In the absence of an economy-wide carbon price signal, policy mechanisms can address the current cost differential between hydrogen (and other renewable gases) and natural gas.

This logic borrows from Australia's experience with renewable electricity sector, which is now considered mature having achieved significant cost reductions over time through a range of policy mechanisms such as the Renewable Energy Target, which surpassed its target of encouraging an additional 20 per cent renewable electricity generation by 2020, compared with 1997 levels.

Various international markets are moving to support the development and use of hydrogen, including in networks, through policy incentives. For example, in early 2023 the United States passed the *Inflation Reduction Act* to subsidise the production of green hydrogen for any use to a level of around $3 per kilogram.

6.3.1. Incentive Mechanisms

Table 12 summarises some of the key advantages and disadvantages of several distinct types of incentive schemes that could be used to increase demand for hydrogen and other renewable gases as an alternative to natural gas.

An incentive scheme could help achieve government policy objectives, including that blending potentially reduces emissions, facilitates early experience with hydrogen and has a low risk profile of off-takers enables supply and demand to be balanced in the energy system, and can unlock the growth of Australia's hydrogen economy as a necessary precursor to later export.

Table 12: Different schemes that incentivise the use of hydrogen or other renewable gases in place of natural gas

Criteria	Brief Description	Potential Advantages	Potential Disadvantages
Certificate-style Scheme	Places an obligation on liable entities (e.g., gas retailers, distribution businesses, etc.) to surrender a certain number of certificates each year. The number of certificates remitted could first reflect a near-term target (e.g., 10% by volume), and once reached (by a certain specified target year, e.g., 2030), a longer-term target (100%) could be set (with an associated long-term date) if it is deemed to be required. • The trajectory of certificate creation over the life of the Scheme could be hard-wired into its design to create certainty for investors. This creates an underlying demand for certificates.	• Because this scheme would mimic the existing Renewable Energy Target scheme, it is a known design and existing governance and institutional frameworks could be leveraged • Certificate prices, and therefore the cost of the scheme, reflect underlying market fundamentals affecting creation of certificates. • Production of eligible gas is decoupled from the location at which the liability is generated. For example, certificates in one location can be used to offset liabilities generated from the sale of gas in another location, giving locational flexibility for production. • Provides a clear investment signal, and, if the target is long-term, can facilitate the establishment of long-term industry infrastructure and capacity.	• Can have higher administrative costs relative to some other schemes due to compliance and verification systems/arrangements (despite this scheme leveraging existing governance and institutional arrangements). • Requires a sufficiently large market to produce accredited gases. • May require reasonably high penalties (above the marginal cost of generation) to incentivise compliance through the surrender of certificates, instead of through the payment of the penalty price. • Should operate for a pre-specified and material length of time, otherwise it could create significant uncertainty for investors.
Feed-in tariff (FiT) Scheme	A set payment level per unit of renewable gas is established by a central body for a certain volume, which is potentially adjustable periodically, to, for example, reflect different levels of required support early on in the hydrogen development phase (e.g., to 10% by volume) versus any longer-term support required once the industry is more established (e.g., 10% - 100%), This would be payable to producers of accredited gases who blend their product into specified gas distribution networks. • Bid selection is on a first-come, first-served basis until a desired quota is	• It is a known design, as it is analogous to several Schemes that were used by some states to promote investment in (predominately small scale) renewable electricity generation facilities. • Simple to understand and it is likely to have relatively low transaction costs. • Mitigates the risk that renewable gas producers could exercise market power to affect prices. • Depending on the duration of the posted FiT rate, it provides income certainty to proponents.	• If renewable gas production were to have naturally occurred even without the FiT, then it generates low economic benefit. • The FiT may not reflect underlying market fundamentals, as the payment level is set centrally before the event. This approach risks low generation if the price is too low, or overpayment if the price is too high.

Criteria	Brief Description	Potential Advantages	Potential Disadvantages
	completed, after which the FiT ceases for new entrants		
Competitive grants/Reverse auction Scheme to procure renewable gases	Government or utility calls for offers of renewable gas in set tranches (e.g., reflecting sizes that are consistent with short to medium term targets such as 10% by volume; sizes reflecting long- term targets), and the most cost-effective and feasible proposals receive a long-term contract or funding support. • Could be augmented via the adoption of a Contract-for-Difference arrangement, linked to the market price of natural gas.	• Provides some flexibility around the timing, size, and location of tranches, hence the mechanism can have regard to the supply/demand fundamentals at that time (noting however that too much flexibility may create too much uncertainty for the industry). • Outcomes are market tested. • Contributions can be capped via the setting of reserve prices, hence providing a means of managing the costs to consumers. • In principle, auctions maintain many of the advantages of feed-in tariffs (income certainty for winning proponents) and are also capable of minimising costs to end-users.	• High set-up costs, which is particularly important if the size of the auction tranches is relatively small. • High transaction costs for bidders due to high upfront project development costs, which may preclude smaller bidders from bidding.

6.4. Hydrogen-Ready Appliance Uptake

As outlined in Chapter 5 of the *AHC 100% Hydrogen Distribution Networks Study – South Australia*, appliances will need to be suitable to operate with 100% hydrogen. The cost of the transition to 100% hydrogen is sensitive to the share of hydrogen-ready appliances in the market, driven by appliance and labour costs required for households that still have conventional natural gas appliances at the time of conversion.

By applying the typical life span of domestic gas appliances and their penetration in South Australian and Victorian households, the effect of mandating all gas appliances to be hydrogen-ready from a certain date on was estimated.

Assuming a mandate to be in place from 2030, 90% of domestic appliances could be hydrogen-ready by 2040. On the other hand, delaying a mandate by five years would reduce the share of domestic hydrogen-ready appliances to 45%. Feasible options that could be explored include:

- Requiring certification of all appliances sold or installed as either dual fuel or hydrogen-ready. This could include standard gas appliances that manufacturers can demonstrate already meet the requirements of a hydrogen-ready appliance, despite not being initially designed or marketed as such.
- Incentivising or creating a rebate program for hydrogen-ready appliances for domestic customers installed ahead of network conversion and/or ahead of the mandate.

Incentivising businesses with Type B appliances installed to have a conversion plan prepared by an approved consultant or appliance supplier/manufacturer

7. 10% Hydrogen Implementation

This Chapter summarises key steps to achieve 10% hydrogen by 2030. These steps were informed by a review of relevant literature and substantial engagement with key stakeholders. Each was assessed against key assumptions and constraints to determine implementation timeframes and associated risks.

7.1. Literature Review

7.1.1. Introduction

There is a significant existing base of research that is foundational to assessing 10% hydrogen in South Australian networks. A review of this literature was undertaken with key insights drawn from:

- case studies of historic infrastructure conversions, including the transition from 'town gas' to natural gas that took place in the 1960s and 1970s;
- international feasibility studies and experiences of hydrogen in networks;
- natural gas appliance conversion studies; and
- future network infrastructure plans.

Where relevant, the primary objective was to identify opportunities and challenges experienced from each process and the lessons learned that could help to ensure a smooth transition to 10% and 100% hydrogen in networks.

7.1.2. Themes

Common themes were found between many of the studies surveyed for this literature review. Themes are covered in Table 13, which also notes associated lessons that could help to ensure a smooth transition to 10% hydrogen.

Table 13: Common themes among reviewed literature

Theme	Lesson learned
Public acceptance	To be successful, major infrastructure transitions require public trust. This can be complex to earn and is influenced by many factors which include: • social, financial, and environmental impacts; • perception of fairness, integrity, and good governance; • trust in governments' capabilities and integrity; and • community participation levels throughout a project's lifecycle.
Public reactions change in different contexts	Different responses were experienced in different states, as well as in urban areas versus rural areas.
Policy mandating	Governments are resistant to interventionist policies, as they can limit customer choice and be contrary to market dynamics that can tend to make them expensive.
Unforeseen challenges	Despite significant preparations, there may still be unforeseen challenges that lead to cost and program overruns.
Difficulties of large-scale conversion programs compared to the past	Large-scale conversion projects are likely more challenging today than historic experiences, due to factors like: • lower trust in government and gas companies. • greater difficulty gaining access to households if fewer people are home on a full-time basis. However, lifestyle responses to the COVID-19 pandemic may make home access simpler than pre-pandemic. • Social media could broadcast and amplify safety incidents and installation problems.

7.2. Implementation Plan

This Section provides a high-level summary of the key steps, timeframes, and underlying assumptions that would be required to reach 10% hydrogen in South Australian networks.

Chapter 3 conceptualised future network infrastructure for South Australia served by hydrogen produced from renewable electricity. This concept is one possible option, developed using likely positioning of electrolysers relative to renewable electricity, storage systems, and demand centres.

As there are unknowns that may impact this implementation, what is presented below is an estimate based on global and local experience. Industry stakeholder workshops were held to inform these steps, which involved:

- Assessing options for converting gas appliances to be compatible with hydrogen.
- Identifying activities that would be required or ideal steps to achieve 10% hydrogen.
- Identifying changes to legislation and regulatory standards that would be required to enable 10% hydrogen.

7.2.1. Description of Steps and Activities

This section provides a high-level summary of the key steps, timeframes, and underlying assumptions that would be required to reach 10% hydrogen by 2030.

Step 1: Establish a renewable gas market framework

Chapter 6 outlines the legal, regulatory and policy actions identified and underway to establish a market for the decarbonisation of gas networks.

Timeframe: As soon as possible, to allow it to take effect within a 2030 timeframe

Step 2: Leverage the work of the Australian Hydrogen Centre and hydrogen demonstration projects to inform detailed planning and delivery

Demonstrations underway including AGIG's HyP SA, HyP Gladstone, and HyP Murray Valley and Jemena's Western Sydney Green Gas Project (JWSGGP) are key to inform the wider development and demonstration of blended gas.

A combination of lessons learned from these project's development and high-level strategic planning undertaken through the AHC provides a strong foundation for industry, governments, and other key stakeholders to undertake next level of detailed planning to achieve alignment on the road ahead.

Timeframe: Present - 5 years

Step 3: Build on existing public acceptance programs

Building on the significant work already underway throughout Australia engaging on the energy transition and the role of renewable gas, consideration should be given to engagement approaches that bring all stakeholders along the journey to 10% hydrogen and ultimately to 100%.

Timeframe: Ongoing

Step 4: Consider updates to standards and testing for gas appliances

Chapter 5 outlines the important of standards and testing regimes for gas appliances could be updated to account for the addition of at least 10% hydrogen as part of a business-as-usual approach.

It will be important to harness the significant expertise that exists in Australia's appliance sector to implement a 10% hydrogen pathway that effectively leverages strong progress to date in Australia and internationally.

Timeframe: Present - 6 years

Step 5: Attain project-based approvals

Linked to reforms underway at step 1 to establish a market for renewable gas, relevant authorities throughout Australia are actively considering streamlined processes to license and regulate the production of hydrogen. This will be key to ensuring community and investor confidence in the safe and coordinated roll-out of state-wide renewable gas supply.

Timeframe: up to 2 years

Step 6: Project-based Financial Investment Decision, procurement of equipment

This process includes acquisition of parts for construction of production and storage facilities, as well as the end receipt and approval of payment.

Timeframe: up to 2 years

Step 7: Construction of production facilities and electricity network connection

For the network concept devised in Chapter 3, ten 50 MW production facilities would be required by 2030. The estimated timeframe of 2-3 years includes all stages of the project plan, from prefeasibility to detailed design, construction, and operation.

Electrical connection to local HV and sub-transmission may require upgrades, new feeders, and substations. The timeframe subsequently includes approvals, design, procurement, construction, testing, and commissioning.

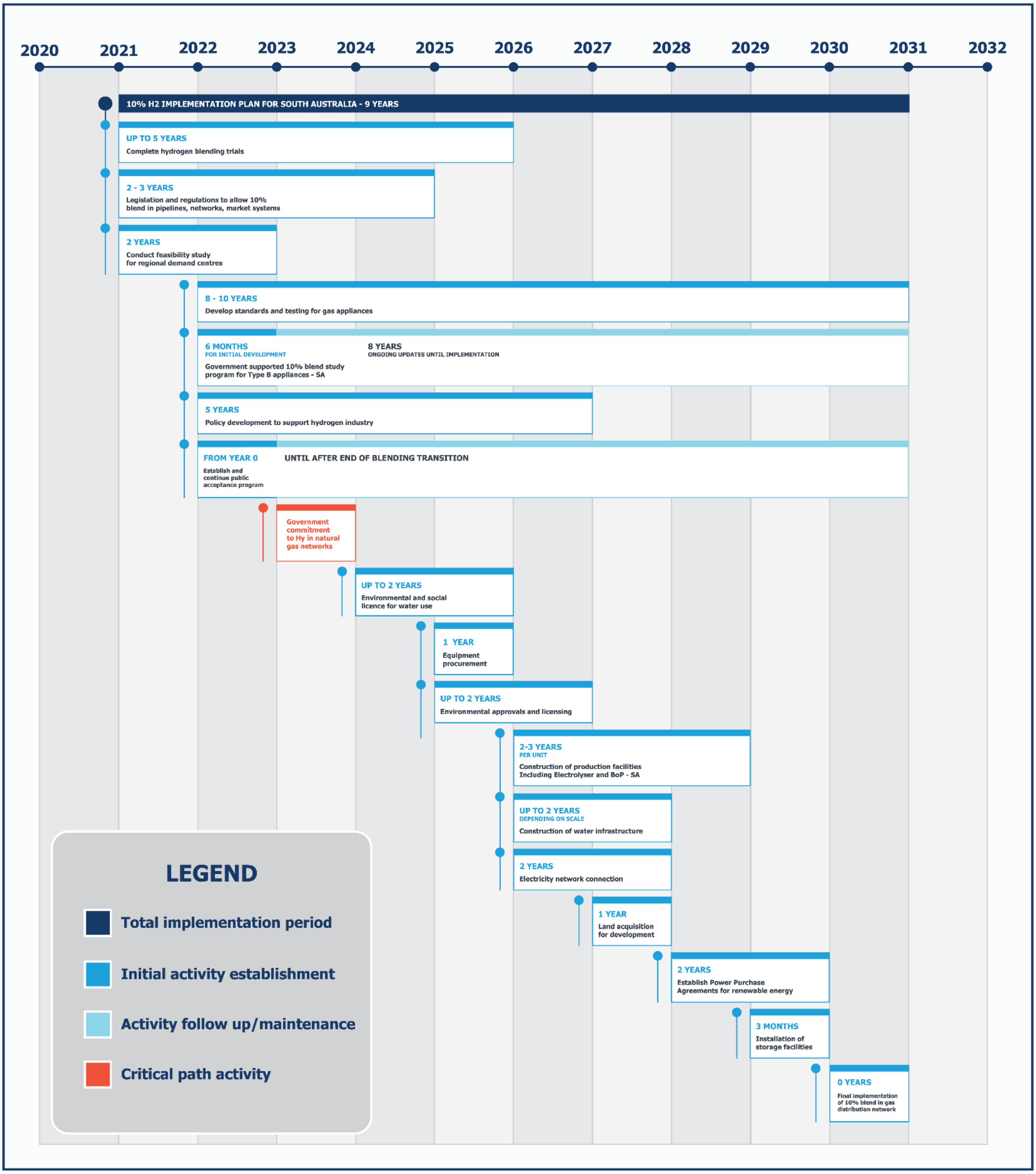
Timeframe: up to 3 years

Step 8: Operations

Ongoing monitoring and optimisation of infrastructure.

Timeframe: Ongoing, supporting 100% network conversion

7.2.2. Timeline



7.3. Implementation Plan Risk Analysis

A risk analysis of the 10% implementation plan was undertaken, with risks and mitigation measures in Table 14. Each risk and mitigation measure were assessed for impact and likelihood on a scale of 1 (very low) to 5 (extreme), and a score was then prepared from the product of these two assessments. The resulting range of scores from 1 to 25 was scaled in a traffic light system as follows:

- 1 – 9 categorised green;
- 10 – 15 categorised orange; and
- 16 – 25 categorised red.

Table 14: Risk analysis showing measurement of risk and mitigation options for 10% hydrogen implementation plan

Risk	Inherent risk			Mitigation measures	Residual risk		
	Impact	Likelihood	Score		Impact	Likelihood	Score
Achieving necessary changes to legislation and regulation [19]	4	4	16	Collaboration between different jurisdictions around Australia to have a common approach for changing legislation and regulation.	4	4	16
The process of updating standards can be slower if not converted at the national level[20]. This is particularly true for the development and certification of 10% hydrogen compatible components for Type B appliances.	4	4	16	Identify key sponsors to support (resources and funding) and accelerate the development of updated standards.	4	3	12
Low interest of investors and users in hydrogen due to lack of incentives/ clear policy / ad hoc commercial agreements	5	3	15	Government funding and incentives, and clear policy that supports the use of hydrogen as a natural gas alternative.	4	3	12

19 Stakeholder consultation revealed that the main challenge for the implementation plan is the lack of certainty about the future of the gas distribution network. This is particularly challenging due to the risk that different jurisdictions around Australia will follow a different path towards the decarbonisation of the natural gas sector.

20 Legislation and regulations must be modified beforehand to cover natural gas with 10% hydrogen blend. This is a critical step in the 10% Implementation Plan and needs to be prior the trial completion.

Risk	Inherent risk			Mitigation measures	Residual risk		
	Impact	Likelihood	Score		Impact	Likelihood	Score
Production of hydrogen subject to availability of electricity transmission network.	4	3	12	Implementing a masterplan to consider present and future power infrastructure.	4	1	4
Risk of delays in implementation plan due to procurement taking longer than expected.	4	3	12	Diversify the procurement strategy, allow adequate lead time for acquiring parts	4	1	4
Delay in project commencement if all environmental approvals, permits, and licenses are not in place.	3	4	12	Early identification of suitable land for hydrogen infrastructure. Also, rezoning of parcels of land for energy and industrial use, complete environmental studies, and action the EIS/EES and EPBC referral.	2	3	6
Hydrogen concentration variations across the network could result in variation of the calorific value at the end user take-off point.	2	5	10	Ensure calorific value measurement and allocation systems and processes are updated to account for variations across the network	2	2	4
Water resource availability poses a risk to the project if sufficient resources are not secured.	5	2	10	Early identification of viable water sources and stakeholder negotiation to secure supply.	5	1	5

8. Financial Modelling

This Chapter summarises the results of high-level modelling regarding the potential costs and customer price impacts associated with 10% hydrogen in existing gas networks.

The modelling was based on the nominal transition path of 10% hydrogen in the early 2030's and 100% hydrogen by 2050, however this Study focuses on the implications for achieving 10% alone. Refer to the *AHC's 100% Hydrogen Distribution Networks Study – South Australia* for further discussion of modelling out to 2050.

Specific inputs were drawn from the following chapters:

- Chapter 3: Renewable Hydrogen Supply, Storage and Transportation
- Chapter 4: Network Readiness
- Chapter 5: Customer Appliance Pathways
- Chapter 7: 10% Hydrogen Implementation

Projections were produced for capital expenditure (capex) profiles, operating cost (opex) profiles (including costs of renewable electricity), and revenue from the sale of hydrogen.

The subsequent projections were then compared to the natural gas price with no future cost of carbon added and are presented for each year to 2030 to illustrate the financial implications and customer bill impacts of transitioning to 10% hydrogen supply over time.

Key findings

1. High-level modelling of customer price impacts demonstrates delivering 10% hydrogen supply would result in stable energy bills similar to projections of pre-energy crisis bills for natural gas supply, excluding any cost of carbon.
2. There could be further upside noting this modelling assessed hydrogen produced via electrolysis powered with renewable electricity only; other carbon-neutral sources (e.g. 'blue hydrogen') and hydrogen produced by non-networked industries (e.g. hydrogen hubs) were excluded. The modelling also excluded cost reductions to hydrogen from any breakthrough technology advances.

While this pathway is the focus of this Study, noteworthy limits to this model include that it:

- Investigates dedicated renewable hydrogen production for converting gas distribution networks to hydrogen. In reality, hydrogen could be produced for various end-uses that could also supply into networks as an additional market as part of a 'hydrogen hubs' model;
- Only considers hydrogen produced from electrolysis with renewable electricity. Other forms of renewable and carbon neutral gases, such as biomethane or hydrogen coupled with carbon capture and storage, were excluded from this scope.
- Has been produced at a 'point in time' and does not consider constant technological advancement and research.

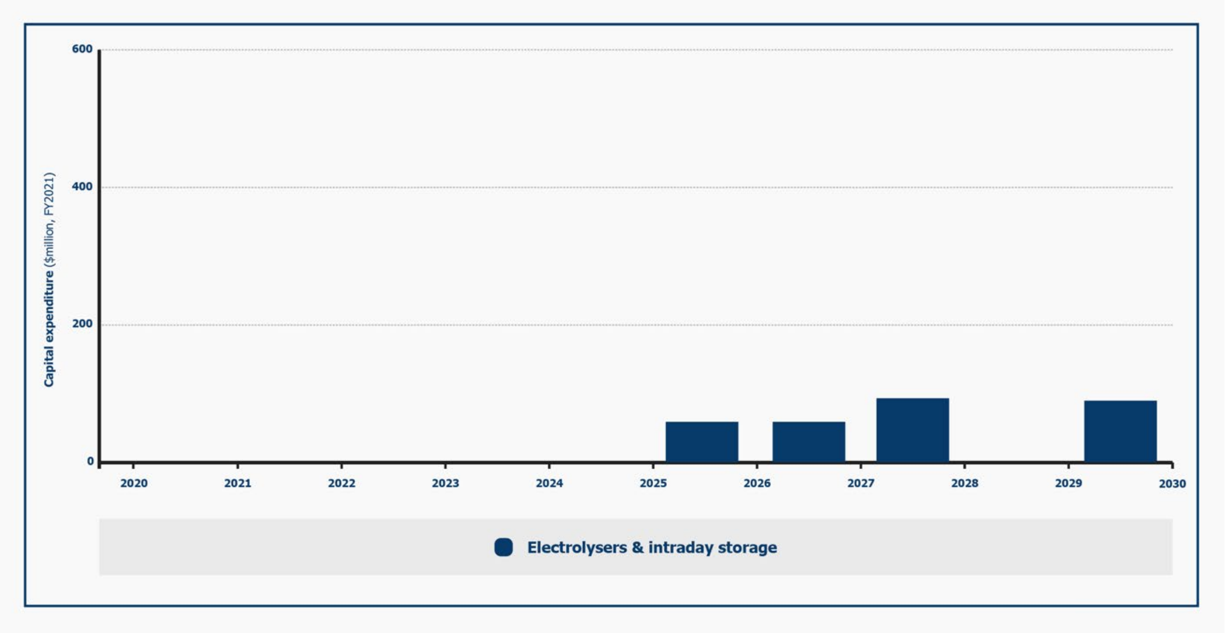
Further, the AHC does not provide a scenario analysis of pathways and associated costings to decarbonise energy consumption of South Australia and Victoria's wider energy systems encompassing electricity, transport, agriculture, and other relevant sectors. Noteworthy reports considering alternative pathways to decarbonising gas supply are summarised in Chapter 9.3 of this Study.

8.1. Financial Projections

8.1.1. Capex Profiles

The capex profile for investment in hydrogen production and storage in Figure 9.

Figure 9: Capex profile for hydrogen production facilities (electrolysers and short-term storage) – South Australia

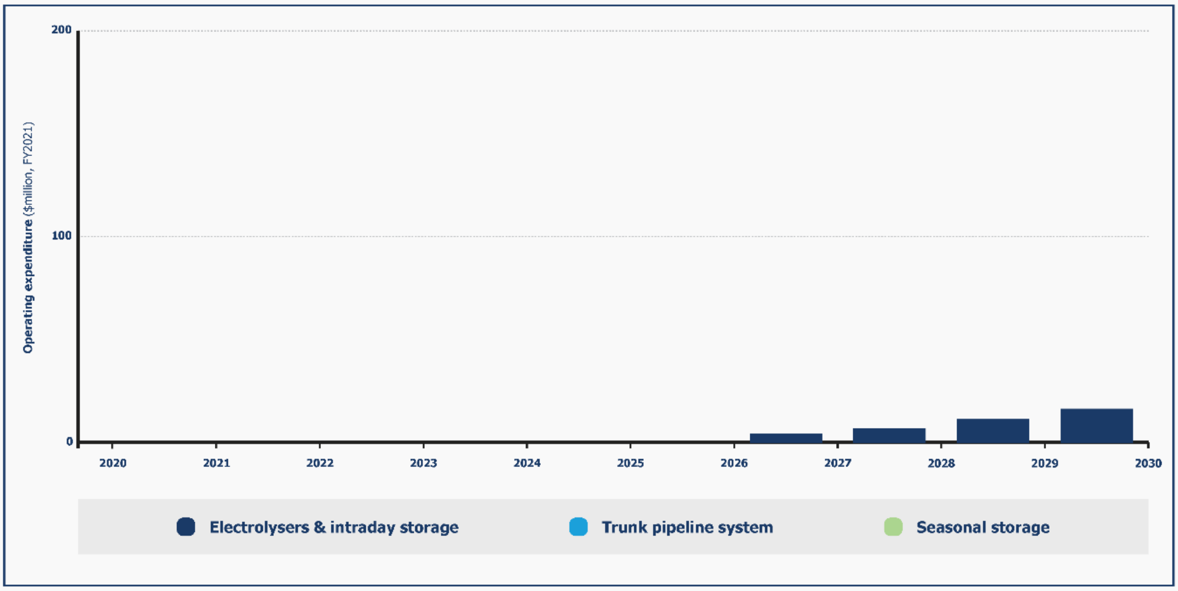


Total investment required until South Australia first reaches 10% hydrogen by volume is $0.4 billion (in real dollars). Capex from the mid-2030's represents activities undertaken to achieve 100% hydrogen.

8.1.2. Opex Profiles

The opex profile for electrolysers and hydrogen storage in South Australia is shown in Figure 10.

Figure 10: Opex profile for production facilities (electrolysers and short-term storage), transmission (trunk pipeline system), and long-term storage



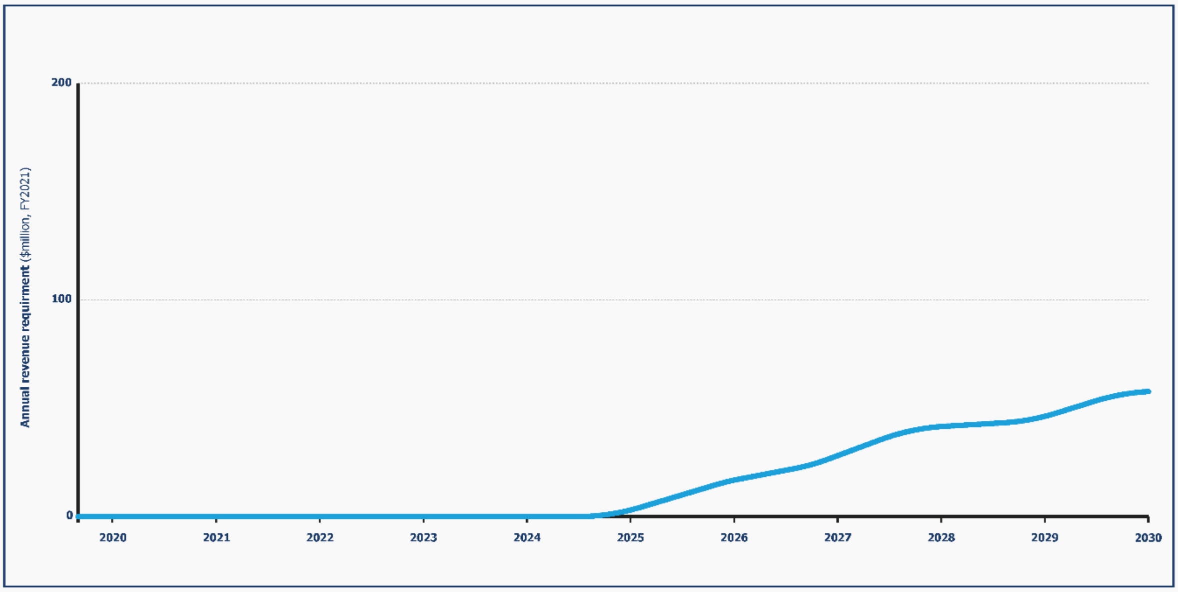
Total opex over the period until South Australia first reaches 10% hydrogen by volume is $106 million (in real dollars) for the electrolysers and short-term storage only.

8.1.3. Revenue from Hydrogen Sales

Figure 11 shows the revenue required to recover lifetime capex and opex of assets needed to achieve 10% across South Australia.

Much of this revenue requirement is to cover the electricity costs for operating the electrolysers. The other major component is the return on capex invested in producing, storing, and transporting hydrogen.

Figure 11: Annual revenue requirement from the sale of hydrogen - South Australia



8.2. Customer Price Impacts

8.2.1. Approach

The customer price impact model prepared for this Chapter presents one possible case for the production and supply of 10% hydrogen. It was prepared out to 2050 noting the AHC's objective to determine feasibility of 100% hydrogen using 10% as a stepping stone.

The model draws on the key findings from previous chapters of this Study regarding infrastructure requirements, and network and end-use readiness. Furthermore, this analysis does not factor for any potential government incentive schemes that would moderate impacts on customer prices. For this reason, it will be important that this analysis is updated on a regular basis – potentially every two years.

8.2.2. Methodology

A standard retail building block approach was taken to model customer price impacts. This is often used by energy regulators to calculate price impacts for electricity and gas customers and separately identify individual cost components. In this case, the following components consisted of:

- **Wholesale costs of energy** – these are the costs to retailers of procuring wholesale natural gas or hydrogen or both to supply to customers, including cost of transport on hydrogen transmission pipelines.
- **Distribution costs** – these are the costs to retailers of securing delivery of natural gas or hydrogen or both to their customers on the gas distribution network.
- **Retail operating costs and retail margin** – these are the costs to retailers of running their retail businesses, and the return required to compensate investors for the risks associated with running a retail business.

The approach for estimating cost impacts is discussed in more detail for each cost component in the sections below. As these sections highlight, estimated customer bill impacts implicitly reflect the total costs along the supply chain (including wholesale, network, and retail functions) of supplying natural gas, or hydrogen, or both, to retail customers.

8.2.3. Cost Component: Wholesale Costs of Energy

The wholesale cost of energy is calculated as the blended wholesale price of gas and hydrogen, grossed for the difference between average wholesale prices and the wholesale cost to retailers of supplying residential customers. There are four key drivers, detailed below.

1. **Blending rate** is the share of hydrogen sales on gas networks state-wide, based on the transition path identified in this study and measured in energy terms rather than volume. This produces a state-wide average blending rate and customer bill impact.

   However, customers on different parts of the network would be supplied with different blending rates at any point in time during state-wide conversion and the costs of supplying different rates would differ because of the different wholesale costs of natural gas and hydrogen. Whether the customer bill impact would be standard across the state or locational and specific to the delivered blending rate is likely to be a public policy matter.

   If the bill impact is standard across the state, the state-wide average customer bill impact projection would reflect that single retail price. If the bill impact is locational, the state-wide average bill would remain representative, but bills would differ between customers depending on delivered blending rate.

2. **The forecast wholesale price of gas** is the Central forecast for South Australia from AEMO's GSOO 2021[21]. These wholesale prices are delivered prices, including tariffs for transmission pipelines.

21 The AHC is aware that AEMO's annual update of the GSOO has been released for 2022 since the drafting of this Report, projecting several scenarios showing higher and lower demand than in the 2021 GSOO Central Scenario. These scenarios reflect the uncertainty in Australia's energy market, for which the 2021 Central Scenario presents a conservative view.

3 **The forecast wholesale price of hydrogen** is the estimated average price for hydrogen for South Australia that would be required to ensure lifetime capex and opex of hydrogen production, storage, and transmission assets are recovered. This average is calculated using a building block approach that provides for a return on assets[22], a return of assets[23], and recovery of opex. The resulting annual revenue requirement is divided by hydrogen sales to determine an average wholesale price required for revenue recovery.

Using this methodology, the calculation inputs are capex and opex estimates outlined in Chapter 3 of this Study.

4 **Difference between wholesale prices and retailers' wholesale costs.** The key reason for this difference is that customers – particularly residential customers – will tend to use more gas at times when gas demand and gas prices are higher. The estimated blended wholesale prices are grossed to account for this, based on estimates of retailers' wholesale costs from the Gas Price Trends Review Report released by the Commonwealth Government in 2017[24].

In this scenario, the wholesale price of hydrogen is also affected by the assumption that hydrogen production, storage, and transmission infrastructure constructed for South Australian gas distribution networks would produce more hydrogen than required. Rather than waste this energy, this excess hydrogen could be sold through hydrogen hubs to transport and export markets from 2040. It was assumed that sales to these new markets would recover the entire opex of excess production and contribute to the capex of the infrastructure used in common.

8.2.4. Cost Component: Distribution Costs

Distribution costs were calculated based on the estimated revenue requirement for gas distribution businesses in South Australia.

The first step was to estimate this revenue requirement with the Post Tax Revenue Model (PTRM) the Australian Energy Regulator (AER) uses for the same purpose. A state-wide PTRM was then rolled out to 2050 on a 'business-as-usual' basis to forecast distribution costs over that period, then interpolated to 2030.

In modelling this cost component, several assumptions were made based on the findings of earlier chapters in this Study.

- The regulated WACC was assumed to remain constant at current levels until 2050.
- Capex was assumed to remain constant in real terms until 2050 at the average level of the last 5 years, after the removal of historical costs associated with mains replacement. This means that capex levels in the model gradually fall from their current levels (which are elevated due to the costs of mains replacement) to levels that are more constant with a long-term average capex level.
- Opex was assumed to remain constant in real terms until 2050 at the average level of the last 5 years.

22 Based on an estimated real pre-tax WACC of 5.5% for merchant assets and an estimate real pre-tax WACC of 2.7% for regulated assets.

23 Based on straight-line depreciation over the assumed economic life of the assets.

24 The Gas Price Trends Review Report can be found here: <https://www.energy.gov.au/publications/gas-price-trends-review-report-2017>

This provides an estimate of the 'business-as-usual' revenue requirement in South Australia for each year until 2050.

The next step is to account for any additional costs associated with 10% and 100% hydrogen. In modelling this cost component, it was assumed that 10% and 100% hydrogen would only bring forward some capex that would occur anyway. As described above, the 'business-as-usual' revenue requirement already incorporates forecasts of additional capex over the period to 2050 (based on historical capex). No change in capex profile for network capacity enhancement was included in the estimated customer bill impact.

The third step is to convert the total annual revenue requirement into distribution costs for customers.

'Business-as-usual' annual revenue requirement	+	annual revenue requirement to cover additional costs of 10% and 100% hydrogen in networks
	= total annual revenue requirement	

This is done by calculating an average annual revenue requirement and then indexing current distribution costs for customers by the change in this average annual revenue requirement.

total annual revenue requirement	÷	total annual pipeline sales
	= average annual revenue requirement	

8.2.5. Cost Component: Retail Operating Costs and Retail Margin

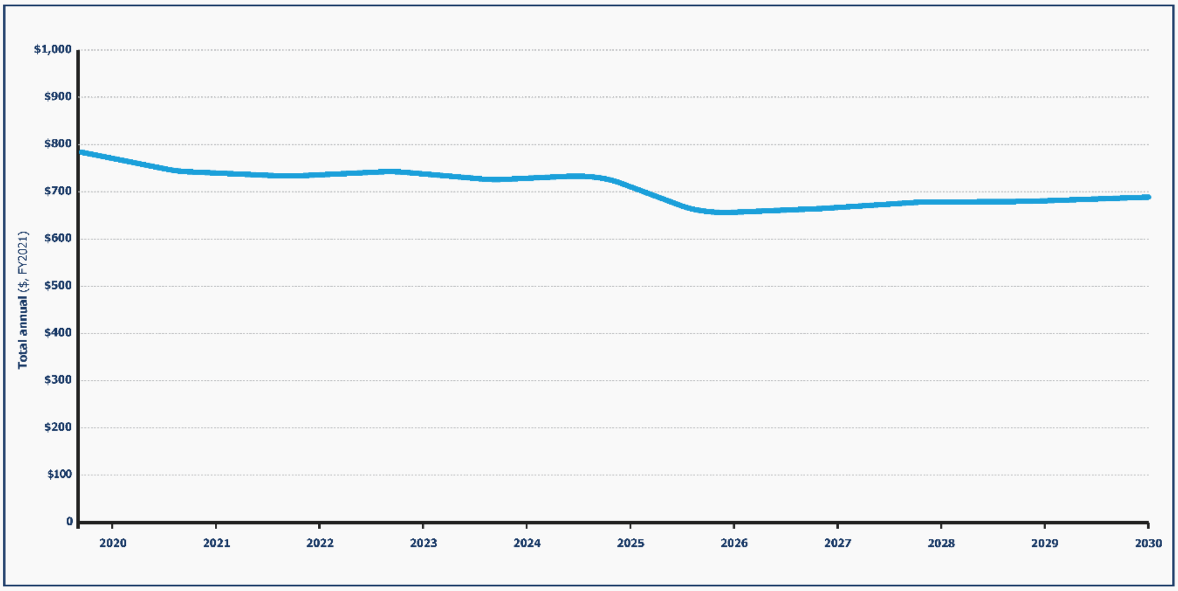
The retailer component of customer bills is based on estimates of retailers' opex, and retail margin form the Gas Price Trends Review Report released by the Commonwealth Government in 2017, held constant in real terms over time[25]. It was assumed that the retailer component is not changed as a result of the addition of hydrogen.

25 The Gas Price Trends Review Report can be found here: <https://www.energy.gov.au/publications/gas-price-trends-review-report-2017>

8.2.6. Results

Customer bill impacts are presented for an average South Australian residential gas customer consuming 15 GJ per annum and are shown in Figure 12. This means the resulting customer bill impact also reflects a state-wide average, although there could be customers on different parts of the network supplied with different mixes of natural gas and hydrogen during the transition to uniform 10% hydrogen. Note that average consumption is based on data from the Gas Price Trends Review.

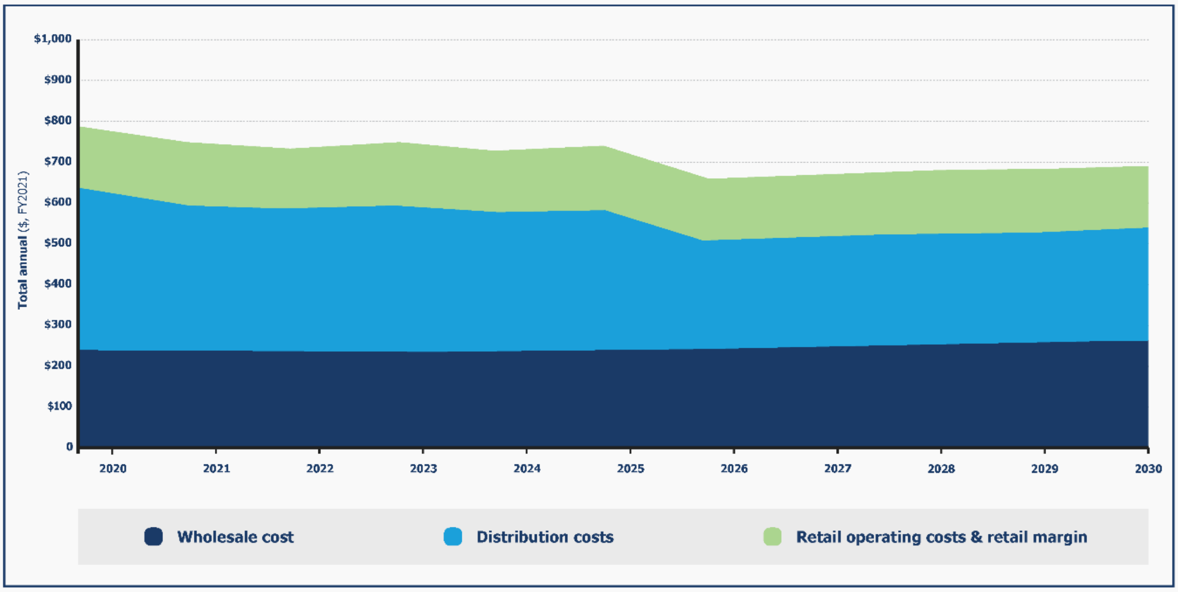
Figure 12: Total bill for an average South Australian residential hydrogen gas customer



This shows that the total bill for an average South Australian residential gas customer is forecast to decrease from an estimated bill of $783 per annum in 2021 to $702 per annum in 2034, representing a decrease of 10% over the period.

Figure 13 breaks down the underlying cost components of this bill: wholesale cost of energy, distribution costs, and retail operating costs and retail margin. It shows that the retail costs are relatively constant over time, while a modest reduction in distribution costs offset by modest increases in wholesale costs.

Figure 13: Total bill for an average South Australian residential gas customer by cost component

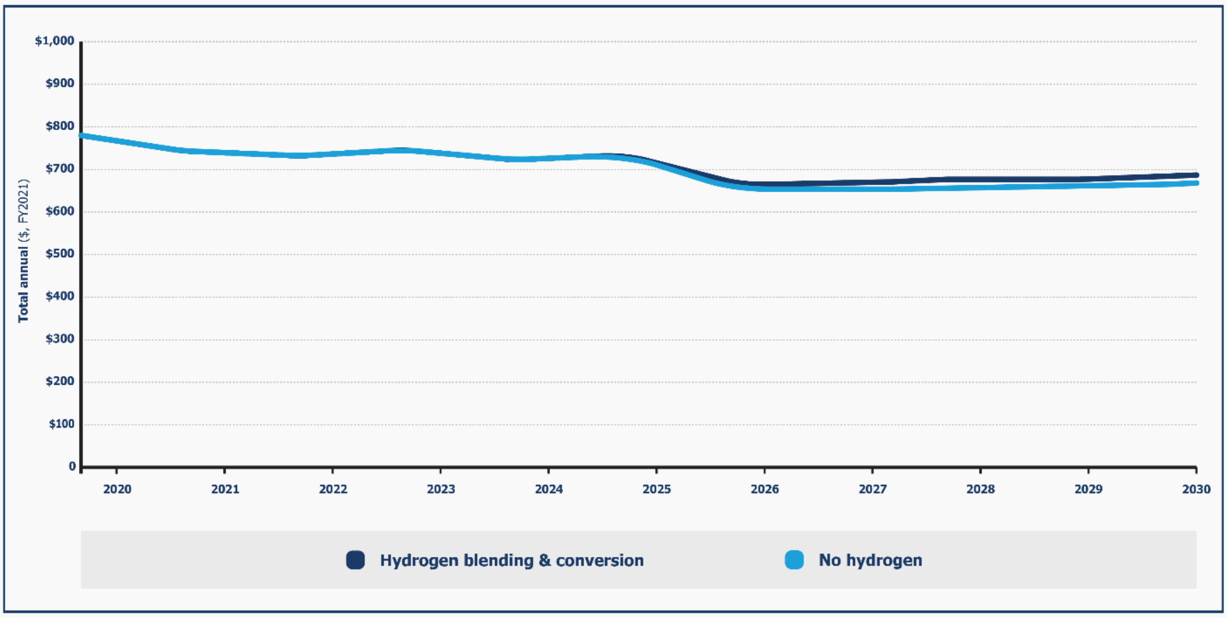


Increases in wholesale costs reflect the change in blending rate over time, with blending commencing in the mid-2020s. As a result, part of the increase in wholesale costs is attributable to the cost of producing, storing, and transporting hydrogen being higher than the wholesale gas price for much of the period.

The wholesale natural gas price also contributes to the estimated wholesale cost increase. AEMO's GSOO 2021 projects the wholesale natural gas price to increase by 7% in real terms from 2021 to 2050. This indicates that, even in the absence of hydrogen, wholesale costs would increase from around $240 per annum in 2021, peaking after 2030.

Figure 14 shows the estimated total bill compared with a scenario where South Australian customers continued to receive just natural gas, indicating the change in the total customer bill in the absence of hydrogen. This was calculated using the same methodology and assumptions used to develop the total bill for the hydrogen case but assumed that only natural gas is supplied, and network and appliance conversion costs not incurred.

Figure 14: Total bill for an average South Australian residential gas customer - with no-hydrogen case



This demonstrates that even without switching to hydrogen, average South Australian residential customer bills are projected to decrease in 2027, before increasing from there from $656 per annum in 2027, when the with-hydrogen case grows slightly higher. At this point, estimates suggest that the bill is $702 per annum, while the estimated bill for the no hydrogen case is $680.

This finding is significant noting the fundamental changes envisioned in this Study to transition the supply chain servicing South Australian gas distribution networks to 10% renewable hydrogen, including around 90 MW in renewable hydrogen production.

There could be further upside noting this modelling assessed hydrogen produced via electrolysis powered with renewable electricity only; other carbon-neutral sources (e.g. 'blue hydrogen') and hydrogen produced by external industries (e.g. hydrogen hubs) was excluded.

8.3. Comparison to Alternate Pathways

This Study does not provide a scenario analysis of pathways and associated costings to decarbonise energy consumption of South Australia's wider energy systems encompassing electricity, transport, agriculture, and other relevant sectors.

Noteworthy recent reports that consider pathway analysis are summarised in Table 15.

Table 15: Noteworthy reports considering alternative pathways to decarbonising gas supply

Author/Commissioning	Title	Date	Report Focus	Key Finding/s
Advisian for the Clean Energy Finance Corporation	Australian Hydrogen Market Study[26]	24 May 2021	Cost of production and competitiveness of low carbon hydrogen in 25 Australian end-use sectors, relative to the incumbent technology.	10% blending is considered viable without significantly increasing risks to utilisation, safety, system durability or integrity. Alternatives, such as electrification and 100% hydrogen networks, are likely to be more important.
Frontier Economics	Cost of switching from gas to electric appliances in the home[27]	24 June 2022	The upfront cost of converting existing Victorian dual fuel homes to electric only	Additional cost categories are significant across several residential customer archetypes and, in conjunction with appliance costs, make domestic electrification a challenging financial prospect.
Frontier Economics for Department of Climate Change, Energy, the Environment and Water	Indicative Analysis of Blending Hydrogen in Gas Networks[28]	11 May 2020	The economics of blending 10% hydrogen in Melbourne	As long as storage is cheap, blending hydrogen is cheaper than electrification by 2030.
Frontier Economics for Energy Networks Australia	The benefits of gas infrastructure to decarbonise Australia[29]	17 September 2020	Economics of conversion to 100% hydrogen across Australia by 2050	Converting to hydrogen – whether produced by SMR or electrolysis – is a cheaper option that total electrification.

26 Report can be found here: <https://www.cefc.com.au/media/nkmljvkc/australian-hydrogen-market-study.pdf>

27 Report can be found here: < https://www.gasenergyaus.au/get/1945/frontier-economics-report-gamaa-july-2022.pdf >

28 Report can be found here: <https://www.industry.gov.au/sites/default/files/2021-09/hydrogen-blending-final.pdf>

29 Report can be found here: <https://www.energynetworks.com.au/resources/reports/2020-reports-and-publications/the-benefits-of-gas-infrastructure-to-decarbonise-australia-frontier-economics/>

9. Additional State-Wide Economic Benefits

This Chapter provides an overview of the additional economic benefits and opportunities that flow from achieving 10% renewable hydrogen in networks. Importantly, it was produced separately to the feasibility assessments and cost build up developed in previous chapters and draws on different inputs and assumptions, which can be found in Section B of the Appendix.

It does so to assess the whole-of-state benefits of 10% hydrogen in networks as opposed to energy infrastructure outcomes only.

Key findings

1. Achieving 10% hydrogen in gas distribution networks could create 88 new jobs for South Australians during construction and 22 new jobs ongoing.
2. Widespread delivery of 10% hydrogen in gas distribution networks helps lay the foundation for Australia's emerging hydrogen industry by developing skills, public acceptance and large-scale projects. Doing so achieves economies of scale while lowering emissions and retaining energy affordability and reliability.
3. Developing large-scale renewable hydrogen production and storage opens the door for Australia's heavy industry, transport, freight, and export sectors to transition to hydrogen.
4. Coordinated action between government and industry will enable these high-value sectors to draw on this new infrastructure to develop scale rapidly.

9.1. Economic Impact Assessment

A preliminary Economic Impact Assessment (EIA) has been undertaken to explore the economic implications of 10% hydrogen in South Australia's gas distribution networks.

An EIA measures the expected change in key economic indicators which are expected to occur as a result of the project, such as job creation, Gross State Product (GSP) and value added to the economy.

The EIA utilised the proposed infrastructure investments and activities that had been outlined in previous chapters to develop an understanding of the direct and indirect economic impacts during their construction and operational phases.

9.1.1. Methodology

Table 16 shows the method adopted to complete the preliminary EIA.

Table 16: EIA methodology - 10% hydrogen by 2030

Step	Key tasks
Step 1 Background review	• Confirm scope, aims, and objectives of hydrogen in networks and any relevant dependences and limitation of the scenario to assess. • Review relevant background information, technical studies, and other assessments to confirm key aspects of hydrogen in networks and any baseline assumptions. • Identify and address any critical information gaps and issues limiting the analysis and evaluation; undertake additional research and prepare proxy indicators using relevant benchmarks and secondary research.
Step 2 Impact analysis	• Identify and assess anticipated economic impacts likely to occur as a result of the construction and operational phases of hydrogen in networks, including for each key stage of the renewable hydrogen supply chain.
Step 3 Confirm assessment parameters	• Confirm key project inputs, such as capital and operational expenditure estimates for each stage of the hydrogen supply chain and expected construction and operational timelines for hydrogen in networks.
Step 4 Economic Impact Assessment (EIA)	• Calculate the expected number of jobs generated by construction and operational phase of hydrogen in networks, using project cost estimates calculated in Step 3 as the key modelling input variable. • Assess how construction and operation of hydrogen in networks will directly and indirectly contribute to the state economy in terms of economic flow-on effects on output and value-added.

Design, construction, and operation of the infrastructure required to achieve the 10% hydrogen would generate a range of direct and indirect economic impacts for South Australia. Estimates of the economic contribution of 10% hydrogen by 2030 were prepared for:

- **Construction Phase:** Economic activity during the construction phase, which is estimated to be across five years.
- **Operational Phase:** Ongoing economic activity that would be generated by the operation and maintenance phase, based on full operations as of 2030.

The economic impacts of both phases have been estimated according to the direct, or project specific outcomes, and indirect impacts which occur because of second round consumption and expenditure economic impacts. These estimates of economic impacts have been prepared with input-out multipliers.

Table 17: Annual Economic Impact Summary - 10% hydrogen by 2030

Construction Phase (annual, over the 5-year construction period)			
	Direct	Indirect	Total
Output ($m)	$18.25	$12.86	$31.11
Employment (FTE)	36	52	88
Value Added ($m)	$6.18	$5.48	$11.66
Operation Phase (annual, as of 2030)			
Output ($m)	$5.91	$6.08	$11.99
Employment (FTE jobs)	6	16	22
Value Added ($m)	$1.95	$2.52	$4.47

According to the analysis summarised in Table 17, the construction phase of 10% hydrogen is expected to create the following direct benefits for South Australia:

- Direct output (spending) of $18.25 million per annum (for five years)
- Full-time equivalent (FTE) employment supported of 36 jobs per annum for each year of the five-year construction program; and
- A total direct value-add to the economy of $6.18 million per annum (for five years).

When the multipliers are considered, total South Australia economy-wide effects are forecast to be:

- Output (spending) of $31.11 million per annum (for five years)
- Full-time equivalent (FTE) employment supported of 88 jobs per annum for each year of the five-year construction program
- A total direct value-add to the economy of $11.66 million per annum (for five years).

The five-year construction program could deliver a significant boost to building and trades sector in South Australia. Additional benefits are also expected across the rest of Australia but have not been reported in this EIA.

Upon completion of the Project, the operational phase is expected to deliver through on-site and supply chain activity generating the following benefits for South Australia:

- Direct output (spending) of $5.91 million per annum
- Full-time equivalent (FTE) employment of 6 ongoing jobs
- A total direct value-add to the economy of $1.95 million per annum

When the multipliers are considered, total ongoing economy-wide effects are forecast to be:

- Output (spending) of $11.99 million per annum
- Full-time equivalent (FTE) employment of 22 ongoing jobs
- A total direct value-add to the economy of $4.47 million per annum.

The above economic benefits are significant in the context of the South Australian economy. Additional benefits are also expected to flow across the wider Australian economy but have not been reported in this EIA.

The assumptions and analysis of this assessment can be found in Section B of the Appendix.

9.2. Sector Coupling Opportunities

While the scope of this study focussed on renewable hydrogen production for 10% hydrogen networks as a priority, integrating aspects of that production with projects that either feed into electrolysis or use electrolysis by-products are being pursued throughout Australia as part of a 'hydrogen hub' model.

The AHC carried out a desktop analysis study to understand the potential for new customers and industries as a result of 10% hydrogen in South Australian gas distribution networks, including what improvement they might have on its overall economics.

It has been assumed developing large-scale renewable hydrogen industries such as ammonia, power generation and export would access their own hydrogen production and therefore not rely significantly on a hydrogen distribution network.

Therefore, the Study considered the hydrogen transport market to be a leading potential opportunity with further analysis in the following section. A summary of the hydrogen transport market is provided in the *AHC 100% Hydrogen Distribution Networks Study – South Australia* study.

9.2.1. Hydrogen By-products

Oxygen, heat, and demineralised water are by-products of the electrolysis process that have applications in industrial or commercial processes. These by-products could provide additional revenue streams for hydrogen production facilities in 2030.

Oxygen could be consumed in several industrial processes or used by hospitals. Its industrial uses include steel manufacturing through the Basic Oxygen Process (BOP) to oxidise iron into steel. The reaction lowers the carbon content of the iron and removes impurities. The process requires blast furnaces that operate at high temperatures to produce the reaction. Further investigation is required to determine whether the demand for oxygen delivery is suitable in this industry.

Another potential use for oxygen is in wastewater treatment plants (WWTP) to increase the efficiency of aerobic treatment processes required for wastewater. WWTP don't often use these processes instead favouring traditional technologies, however better availability of oxygen may improve the feasibility of upgrades required to perform the processes.

Large WWTPs in South Australia could be potential partners in a hydrogen production facility project. A hydrogen facility supplying oxygen to these treatment plants would require additional infrastructure and/or truck transport capabilities to be able to deliver the oxygen.

A further study could understand the cost of doing so, and the potential demand at each of these sites.

Glossary

Term Used	Meaning
ACCC	Australian Competition and Consumer Commission
ACCU	Australian Carbon Credit Unit/s
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGA	Australian Gas Association
AGIG	Australian Gas Infrastructure Group
AGN	Australian Gas Networks
AHC	Australian Hydrogen Centre
ALARP	As Low as Reasonably Practicable
ARENA	Australian Renewable Energy Agency
AUD	Australian Dollar
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
BOC	BOC Limited
BoP	Balance of Plant
BOP	Basic Oxygen Process
BU	Business Unit
CAPEX	Capital expenditure
CDL	Critical Defect Length
CEFC	Clean Energy Finance Corporation
CEO	Chief Operating Officer
CFADS	Cash Flow Available for Debt Service
CfD	Contract for Difference
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO2/CO_2	Carbon Dioxide
COVID-19	Coronavirus Disease 19
CPI	Consumer Price Index
CRC	Cooperative Research Centre
CSG	Coal Seam Gas
CV	Calorific Value
DA	Development Approval/s
DEECA	Department of Energy, Environment, and Climate Action (Victoria)
DPIE	Department of Planning, Industry and Environment (NSW)
DSP	Demand Site Participation
DTS	Declared Transmission System (Victoria)
DWGM	Declared Wholesale Gas Market (Victoria)
EHV	Extra High Voltage
EIA	Economic Impact Assessment

Term Used	Meaning
EIGA	European Industrial Gases Association
ENA	Energy Networks Australia
EoI	Expression of Interest
EPA	Environment Protection Authority (Victoria)
EPC	Engineering, Procurement and Construction
EPCM	Engineering, Procurement, Construction and Management
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
ESV	Energy Safe Victoria
ETI	Energy Transition Initiative
EV	Electric Vehicle
FCAS	Frequency Control and Ancillary Service/s
FCEV	Fuel Cell Electric Vehicle
FEED	Front-End Engineering and Design
FFCRC	Future Fuels Cooperative Research Centre
FID	Financial Investment Decision
FiT	Feed-in Tariff
FSA	Formal Safety Assessment
FTE	Full-time Equivalent
Future Fuels CRC	Future Fuels Cooperative Research Centre
GAMAA	Gas Appliance Manufacturers Association of Australia
Gas fitter	A person trained to connect, disconnect, and service gas fittings and appliances.
GJ	Gigajoule
GL	Gigalitre
GM	General Manager
GMMP	Groundwater Management & Monitoring Plan
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
H2/H_2	Hydrogen
HA	Hazardous Area
HA	Hazardous Area
HAZID	Hazard Identification workshop
HAZOP	Hazard and Operability Study
HDPE	High Density Polyethylene
HGL	Hydrogen Generation Licence
HGV	Heavy Goods Vehicle/s
HHV	Higher Heating Value
HP	High Pressure
HP1	High Pressure 140 to 515 kPa
HP2	High Pressure 515 to below 1,050 kPa
Hy4Heat	Hydrogen for Heat Program
HyP Gladstone	Hydrogen Park Gladstone
HyP Murray Valley	Hydrogen Park Murray Valley
HyP SA	Hydrogen Park South Australia

Term Used	Meaning
ICE	Internal Combustion Engine Vehicle
ILI	In-line Inspection
I-O multiplier	Input-Output multipliers are commonly used to quantify the economic impacts (both direct and indirect) relating to policies and projects.
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IRENA	International Renewable Energy Agency
ISP	Integrated System Plan
JDA	Joint Development Agreement
JV	Joint Venture
kg	Kilogram
kL	Kilolitre
KM	Kilometre
kPa	Kilopascal
kPag	Kilopascal Gauge
kv	Kilovolt
kW	Kilowatt
KWh	Kilowatt hour
L	Litre
LCOH	Levelised Cost of Hydrogen
LEL	Lower Explosive Limit
LFL	Lower Flammability Limit
LGC	Large-scale renewable Generation Certificate
LHV	Lower Heating Value
LIL	Large Industrial Load
LP	Low Pressure
MAOP	Maximum Allowable Operating Pressure
MAPS	Moomba to Adelaide Pipeline
MCH	Methylcyclohexane/toluene
mg	Milligram
MGN	Multinet Gas Networks
MIE	Minimum Ignition Energy
MJ	Megajoule
MJ/Sm^3	Megajoule per Standard Cubic Metre
mL	Millilitre
mm	Millimetre
MMBtu	Metric Million British Thermal Unit
MP	Medium Pressure
MPa	Megapascal
MSP	Moomba to Sydney Pipeline
Mt	Metric Tonne
$MtCO_2$-e	Metric Tonnes of Carbon Dioxide Equivalent
MVA	Megavolt amperes
MW	Megawatt
MWh	Megawatt hour

Term Used	Meaning
NCC	National Competition Council
NDT	Non-destructive Testing
NEM	National Electricity Market
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NEW	North East Water
NGL	National Gas Law
NGR	National Gas Rules
NREL	National Renewable Energy Laboratory (US)
NSW	New South Wales
O&M	Operation and Maintenance
ODS	Oxygen Depletion System/Sensor
OEM	Original Equipment Manufacturer/s
OPEX	Operating expenditure
OTR	Office of the Technical Regulator (South Australia)
PCF	Pressure Correction Factor
PE	Polyethylene
PEM	Proton Exchange Membrane
PGE	Petroleum and Geothermal Energy
PHES	Pumped Hydro Energy Storage
PJ	Petajoule
PLEXOS	Energy Market Simulation Software
PPA	Power Purchase Agreement
PRS	Pressure Reduction Stations
Purging (to purge)	When an inert 'purge 'gas is introduced into a closed system to prevent the formation of a combustible atmosphere.
PV	Photovoltaic
PVC	Polyvinyl Chloride
QGDN	Queensland Gas Distribution Network
QSN	Queensland, South Australia and New South Wales Link
REZ	Renewable Energy Zones
RFQ	Request for Quotation
RIS	Regulation Impact Statement
RO	Reverse Osmosis
SA	South Australia
SAOP	Safety and Operating Plan
SCADA	Supervisory Control and Data Acquisition
SEA Gas	South East Australian Gas
SEPS	South East Pipeline System
SESA	South East South Australian Pipeline
SG	Specific Gravity
SIPS	System Integrity Protection Scheme
SLD	Single Line Diagram
SLO	Social License to Operate
SMIL	Small to Medium Industrial Load

Term Used	Meaning
SMR	Steam Methane Reforming
SMS	Safety Management Study
SMYS	Specified Minimum Yield Strength
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
STEM	Science, Technology, Engineering, Mathematics
STTM	Adelaide Short Term Trading Market
TBC	To Be Confirmed
TJ	Terajoule
TP	Transmission Pressure
TUOS	Transmission-use-of-system
TWA	Time Weighted Average
UAFG	Unaccounted For Gas
UFL	Upper Flammability Limit
USD	United States Dollar
UTS	Ultimate Tensile Strength
VIC	Victoria
VRET	Victorian Renewable Energy Target
VTS	Victorian Transmission System
WACC	Weighted Average Cost of Capital
WI	Wobble Index
WWTP	Wastewater Treatment Plant

Australian Hydrogen Centre

Appendix: 10% Hydrogen Distribution Networks South Australia Study

Assessing the feasibility of delivering 10% renewable hydrogen in South Australia's gas distribution networks

May 2023

Table of Contents

Appendix A Network Readiness

Appendix A details assessments that were performed to understand the augmentations that may be required for those existing gas distribution networks to transport 10% hydrogen as referred to in Chapter 4 of the *10% Hydrogen Distribution Networks – South Australia*.

The scope of these assessments include:

- pipes and components (Section A1);
- network operational processes (Section A2); and
- the capital and operating costs of the modifications required for each (Section A3).

A.1 Natural Gas Component and Pipe Compatibility

Natural Gas Pipe Compatibility Results

Pipes in South Australia's gas distribution network were identified in a desktop study using documentation provided by AGN SA.

A full compatibility assessment of piping materials and jointing methods with 10% hydrogen was then conducted. As detailed in the Study, distribution licensed pipelines, distribution piping, and joint types in South Australia are generally acceptable for use with 10% hydrogen.

Natural Gas Component Compatibility Results

Components in South Australia's gas distribution network were identified in a desktop study using documentation provided by AGN SA.

A full compatibility assessment was then conducted and the results for components by type, make, and model, are shown in Table 1, Table 2, Table 3, Table 4, Table 5, Table 6, and Table 7.

Table 18: Components that require materials testing

Component type	Make	Models	Material information required
Regulators	Pietro Fiorentini	FE10 FE25	Investigate compatibility of Zamak (and approve component use at 100% hydrogen).Do
Domestic gas fitters	-	-	Investigate hydrogen compatibility of zinc.
Various	Various	Various	Investigate hydrogen compatibility of cast iron at pressures above 7 kPa.

Table 19: Components to be replaced

Component type	Make	Models	Material information required
Large bore valves	Brook	B600E	Cast iron body and SS410 stem
	Keystone	AR2 butterfly	Cast iron body with 17-4PH SS stem

Table 20: Cast iron components

Component type	Make	Models	Material information required
Large bore valves	Audco	M series Class 125	Replace if used above 7 kPa, or perform material testing to prove material compatibility with hydrogen at higher pressures
	John Valves	FIG 600	
Regulators	Fisher	298T, 99, 61	
	Mooney	Flowmax	
	AMC	Reliance 1800,3000, 3010, 1203	
	Elster	J125	
	Sensus	243RPC	
Filters/strainers	Donkins	BD240R-290	
	ME MACK	Y Strainer	
	CLAM	Proprietary item: right angled filter	

Table 21: Components with incompatible materials to be risk assessed for their application

Component type	Make	Models	Material information required
Large bore valves	Richards	R43, R723, R733	Risk assess use of Inconel
	PBV	5800/6800	
	Sferova	TM2/Tm3	
Small bore valves	Swagelok	SS-EGUF8	Risk assess use of S17400SS needle
Regulators	AMC	Axial Flow Valve, Radial Flow Valve	Risk assess use of 17-4(PH) SS
	Pietro Fiorentini	PF Reflux 819 FO	Risk assess use of 416 SS
	Crosby	951 Series	Risk assess use of416 SS and 17-7PH or Monel or Hastelloy C

Table 22: Components for which material information is not known

Component type	Make	Models	Material information required
Large bore valves	Cameron	WKM R603 NH	ALL
	Richards	R346, R46	ALL
		93300A RP6B MK3	ALL
Regulators	Gorter	Cocon 13, 26	Confirm type of steel and any plastic
	Fisher	64 HPR 67F	ALL
		161, 168, EZH	Confirm type of steels used and in what applications
	Mooney	15H01G	ALL
	AMC	Reliance 2000	ALL
	AMPY Email 300	Spec 23, 59, 68, 78	Confirm any metals used
	Grove	Model 80, 81, 83	ALL
	Reynolds	670, 678, 682	ALL
	Donkins	688, 999	ALL
	Pietro Fiorentini	FEX, VS/AM	Confirm any plastics used
		Dival 300 & 512 LTR, Reval	ALL
	RMG	650, 850	ALL
	Welker	Welker Jet	Confirm application of 1045 CS
	Honeywell	HON 5020	Confirm type of SS used
	EDMI/Atlas	TR200B, TR143	Confirm type of SS used
Meters	Dresser	Roots	Confirm type of steel and any plastics
	Actaris	1000A	Confirm any metals used
	L&G / AMPY	Model 750, 1010, 602, 610	Confirm type of steel
	EDMI / Atlas	RK MR8, U8, U10	
Filters/Strainers	ME MACK	6761A-050	ALL
	Grove	104-00019	
	NUPRO	55	

Component type	Make	Models	Material information required
	Fisher P252	Type P252	

Table 23: Components that require materials testing

Component type	Make	Models	Material information required
Regulators	Pietro Fiorentini	FE10 FE25	Investigate compatibility of Zamak (and approve component use at 100% hydrogen)
Domestic gas meter fittings	-	-	Investigate hydrogen compatibility of zinc
Various	Various	Various	Investigate hydrogen compatibility of cast iron at pressures above 7 kPa

Table 24: Components with cast iron, nickel alloy, or martensitic stainless steel options - material selection to be confirmed

Component type	Make	Models	Material information required
Large bore valves	Nordstrom	-	Confirm plug material (SS or Monel). Replace if Monel or martensitic SS.
	Audco	Standard M series and Super H series	Confirm plug material. Replace if cast iron at pressure above 7 kPa
	Keystone	F2 butterfly	Confirm whether body is cast iron or carbon steel. Replace if cast iron at pressure above 7 kPa
	Bray	S31-13	Confirm body material. If cast/ductile iron, and used at pressure above 7 kPa, replace. If not, risk assess, considering Monel or 17-4PH SS stem
Small bore valves	Fisher	OSE	Confirm body material. Replace if cast iron at pressure above 7 kPa
Regulators	Gorter	Cocon 1-12	Confirm body material. Replace if cast iron at pressure above 7 kPa
	Fisher	62, 627, 289H, 299, 166, EZR, 66	Confirm body material. Replace if cast iron at pressure above 7 kPa
		98H PRV	Confirm body material. If cast/ductile iron at pressure above 7 kPa, replace. Otherwise, confirm seat option. If 416SS metal/metal seat, risk assess.

Component type	Make	Models	Material information required
	Mooney	Flowgrid FG/SG	Confirm body material. If cast iron at pressure above 7 kPa, replace. Otherwise, risk assess, considering 17-4PH SS throttle plate
	AMC	Reliance Z 138	Confirm body material. Replace if cast iron at pressure above 7 kPa
	Donkins	226 MK2 / MK3	Confirm body material. Replace if cast iron at pressure above 7 kPa
	Pietro Fiorentini	Dival 100/160/2Div50/600, Norval, Aperval	Confirm body material. Replace if cast iron at pressure above 7 kPa
		Reval 182	Confirm whether body is cast/ductile iron. If yes, and used at pressure above 7 kPa, replace. Otherwise, risk assess, considering 416 SS stem.
Meters	Actaris	Flxie Turbine Meter	Confirm body material. Replace if ductile iron at pressure above 7 kPa
	Sensus / Rockwell	RK T18 Turbine	Confirm body material. Replace if cast iron at pressure above 7 kPa
		RK MKII and IIE Turbine	Confirm body material. Replace if cast iron at pressure above 7 kPa
	Elster Instromet	TRZ2 (turbine) and RVG (rotary)	Confirm body material. Replace if cast iron at pressure above 7 kPa

A.2 Potential Hydrogen Considerations for Current Safety and Operating Procedures

Listed below are potential considerations for safety and operating considerations when factoring for hydrogen supply, referenced in the Study. These are not likely to present concerns or major step changes to current procedures.

Table 25: Register of updates required to operating procedures at 10% blending

Category	Action description
Design of system for safe operation	Consider a revision of any leak detection concentration thresholds, (such as 5%LEL for entering confined spaces) though it is expected that 10% accuracy impact will be immaterial.
Ongoing operation and maintenance	Only live weld to new approved procedures applicable to hydrogen service of the relevant mol%.
	Review approval framework for non-piggable pipelines to ensure they meet the integrity management requirements of ASME B31.12.
	Review pipeline condition, particularly for cracks, before introducing hydrogen.
	Revise pipeline defect assessment procedures as outlined in ASME B31.12.
	Assess network flow capacity and the ability of the system to deliver energy

A.3 Capital Replacement Cost Estimates

Replacement of Components made with Hydrogen-Incompatible or Unknown Materials

Table 11 notes the costs of replacing incompatible components in South Australia's gas distribution network.

This is a conservative estimate given a majority of the gas distribution system historically operated on town gas, comprised of up to 61% hydrogen, and because total replacement is only necessary if further research and/or risk assessment deem replacement is required.

The following considerations were made to estimate these costs:

- Costs to replace filters, strainers, meters, and other components have been excluded.
- Quantities of regulators and valves in the AGN networks were based on spreadsheets provided by AGIG in August 2021 that list quantities and types of valves and regulators across the two AGN networks. The lists did not differentiate the components in each network, so it was assumed that AGN Vic has 60% of the total quantity of each valve, and AGN SA has the remaining 40%.
- Quantities of regulators and valves in the Multinet network were estimated based on quantities in the AGN Vic and SA networks as a guide.
- Quantities of regulators and valves in the AusNet Services network were estimated using facility drawings provided by AusNet, and then multiplying those quantities by the number of facilities in the network (refer to Table 9) and supplemented using the AusNet Services Transmission Pipeline Isolation Plan AMS 30-06 1.0.
- Sizes of each valve and regulator are not known. An average cost for each component has been assumed as per Table 10 and Table 11, which roughly aligns to the cost for a DN100 component.
- Components for which makes and models could not be identified have not been included.
- Demolition, installation, and commissioning costs were assumed to be required for every component. Direct replacement of each component was assumed to require 2 operators for 4 hours, at a cost of $50 per person per hour. Note this is a conservative assumption as upgrades to multiple components at the same facility would enable reduction in costs for mobilisation/demobilisation/isolation, etc. However, no allowance was made for re-design required if replacements are not an exact fit.

Table 26: Number of facilities per network (at 2022)

Item	AGN VIC	Multinet	AusNet
Injection points	54	7	41
Regulating Stations	142	236	146
Custody transfer meter stations	58	20	

Table 27: Estimated unit costs for each type of replacement component

Item	Estimated cost
Large bore valve	$1000
Small bore valve	$200
Customer regulator	$10,000
Network regulator	$20,000
Injection Point regulator	$50,000
Pilot regulator	Included in injection point/network regulator price

Table 28: Estimated costs for component replacement, South Australia

Item	AGN SA	
	Qty	**Cost**
Components with cast iron and martensitic stainless steel	-	$1,658
Components with cast iron	2268	$16,715,662
Components with nickel alloys or unsuitable stainless steels	231	$4,340,309
Components with unsuitable material options (selection to be confirmed)	1723	$24,451,461
Components without known material information	502	$6,032,472
TOTAL PARTS COST		**$51,541,562**
Part delivery (10% of total parts cost)		$5,154,156
Site works to perform replacement (calculated per component)	4726	$1,890,240
GRAND TOTAL		**$58,585,958**

Replacement of Hazardous Area Rated Electrical Equipment

Hydrogen as a process fluid can change the Hazardous Area (HA) compliance of electrical equipment due to a change of both Gas Group and Temperature Class. Hydrogen is in Gas Group IIC and Temperature Class T1; this is the most volatile Gas group, and therefore it requires the most onerous safeguarding. These changes can be significant at 100% hydrogen supply but are less impactful or even negligible with 10% hydrogen.

Any equipment already installed and operating but rated for a Gas Group IIA or IIB must be replaced with a gas group IIC equivalent instrument. For the three types of facilities - Injection Point, Field Regulator and Customer Meter Set - there are 6 (six) instrument types that require hazardous area rating and hence will be non-compliant with respect to hydrogen use:

- flow / volume correctors;
- limit switches;
- junction boxes;
- temperature transmitters;
- solenoids; and
- isolator switch.

Three scenarios are provided for consideration, to estimated costs (+/-50%) of replacing all non-compliant instruments of each type:

1. Replace all instruments that are rated for Gas Group IIA and IIB, and replace all items with missing information.
2. Replace all instruments that are rated for Gas Group IIA and IIB.
3. Replace all instruments that are rated for Gas Group IIA and IIB, and replace all items with missing information and relocate RTU / DBs at 50% of outdoor locations.

For all three scenarios, time has been allocated for engineering which includes:

- Creation of datasheets for new Hazardous Area equipment.
- Design/Review for new junction box(es).
- Installation Scope(s) of Work for all sites with equipment installations.
- Cable Calculations / Review for new relocated distribution board locations.
- Review / Selection of new relocated Remote Telemetry Unit and distribution board locations. All of the new (replacement) instrumentation pricing has been based on equipment that is compliant for gas group IIC, temperature class T1 and are appropriate for use in the indicated zone identified in the provided information.

Where zoning information was not provided/available, HA Zone 1 was assumed for the specification of equipment.

The estimates are based on there being 3 "Injection Point" sites, 257 "Field Regulator" sites and 253 "Customer Meter Set" sites across South Australia.

Table 29: Numbers of facilities

Facility type	AGN SA
Injection Point	3
Field Regulators	257
Customer Meter Set	253

Table 30: Estimated price per unit of each hazardous area rated replacement instrument

Instrument type	Manufacturer	Model	Cost	IECEx Certificate
Flow / Volume Correctors	Honeywell	EK220	$3000	IECEx LCIE 16.0003X
Limit Switches	Honeywell	LS4A1A	$350	Simple Device
Junction Boxes	Pepperl and Fuchs (Govan)	GUB*	$2000	IECEx INE 14.0042X
Temperature Transmitters	Yokogawa	YTA610	$1500	IECEx FMG 16.0014X
Solenoids	Norgren-IMI-Herion	80207 65	$650	IECEx KEM 09.0068X
Isolator Switch	Crouse-Hinds	GHG 263	$1325	IECEx BKI 07.0012

Table 31: Cost breakdown for each scenario of hazardous area equipment replacement, AGN SA

Scenario	Equipment & Materials	Installation Cost	Engineering and Owner's Cost	Uncertainty/ Contingency	Total cost
Scenario 1	$2,069,498	$803,200	$660,721	$636,015	$4,169,434
Scenario 2	$2,077,831	$752,500	$650,976	$626,635	$4,107,942
Scenario 3	$2,750,845	$1,560,600	$991,632	$954,554	$6,257,631

Distribution Licensed Pipelines Excluded from Assessment

Several licensed transmission pipelines with MAOP above 2800 kPag or high design factor, as listed in Table 17, were excluded from the assessment in this project. High pressure and high design factor pipe require a more detailed review on a case-by-case basis. Methods of assessment recommended for each pipeline are discussed in Table 15. Estimated costs to perform these assessments are summarised in Table 15, and the cost per network is shown in Table 16. Costs for in-line inspection (ILI) of pipelines have not been included but may be recommended in practice. These costs are for activities that are recommended for action before any level of hydrogen is introduced.

Table 32: Estimated unit costs for each type of pipeline assessment

Item[30]	Estimated cost
Engineering assessments	$50,000
Dig-up and scraping for material characterisation and hardness spot-tests	$50,000
Sample retrieval using:	
• Simple hot-tap	$250,000
• Stopple and bypass to remove section	$1,000,000
Testing material in air	$10,000
Testing in hydrogen	$200,000

30 Definitions

- Dig-up – A small excavation to expose the buried pipeline and remove a section of coating for the purposes of inspecting the pipe surface and potentially taking samples (scrapings) for characterisation of the material. Afterwards the pipeline is re-coated and re-buried.
- Hot-tap – Hot tapping equipment is used to cut out a circle of material from the pipe, to use for material testing.
- Stopple – Where one hot-tap would not retrieve enough material, two hot-taps, stopples and a temporary bypass are used to isolate a section of pipeline which can be cut out and replaced with a new piece.
- Test – air – Testing of material properties in air, focussing on actual yield strength, tensile strength and ductility determined through tensile testing, and then fracture properties determined through fracture testing. Fracture testing would use both Charpy and a J-R curve testing. Fatigue crack growth rate testing may also be completed.
- Test – hydrogen – Testing of material properties in hydrogen, focussing on the fracture properties as measured using J-R curve testing in a hydrogen chamber. Fatigue crack growth testing and tensile property testing may also be completed. Charpy is not feasible in a hydrogen environment.

Table 33: Estimated costs for pipeline assessment in each network

Item	AGN SA	
	QTY	Cost
Total engineering assessments	1	$12,500
Dig-up and scraping for material characterization and hardness spot-tests	-	-
Sample retrieval[31], using: • Simple hot-tap • Stopple and bypass to remove section	-	-
Testing material in air	3	$30,000
Testing in hydrogen	1	$200,000
Contingency – additional hot taps network-wide	2	$500,000
Totals		**$742,500**

Table 34: Pipelines excluded from assessment

Network	Pipeline License	Pipeline Name	MAOP (kPa)
AGN SA	SPL 11	Riverland Pipeline	9525

31 It has been assumed that there are no original spares of installed pipe available, except for Zaplock pipe.

Appendix B Economic Benefits

The AHC considered the broader economic benefits that would be achieved by 10% hydrogen in South Australia's gas distribution networks in addition to the feasibility assessment and cost build-up presented in the *10% Hydrogen Distribution Networks Study – South Australia* Report.

This analysis drew on different inputs and assumptions to the rest of the Report so that an economic impact assessment of whole-of-state benefits of state-wide blending could be made. These separate inputs and assumptions are detailed in this Appendix Section.

B.1 Assumptions and Analysis of Economic Impact Assessment

Key assumptions

The EIA's key assumptions and parameters expected for the construction and operation of 10% state-wide blending in South Australia by 2030 are outlined in Table 18.

Table 35: Key assumptions and parameters - 10% state-wide blending by 2030

Assumption	Parameter
Construction	
Project Timeframes	• Five-year construction period from 2025 to 2030.
Electricity Generation	• 360 GWh p.a. of renewable energy generation will be requiredto support the Project. Solar and wind energy is assumed.
	• 25%, or 30 MW, of new installed solar and wind energy capacity will need to be developed specifically to support theProject. The remaining 75% of renewable energy will be sourced from existing facilities.
	• Cost per installed MW of new renewable energy is estimated at $1,685,000. This value is based on benchmarking analysis of investment costs associated with a mix of proposed, approved and recently constructed utility scale solar and wind facilities across Australia.
	• By 2030, it is assumed 40% of construction investment for new renewable energy infrastructure will flow to South Australia, 10% will flow interstate and 50% will be associated with imports. These shares are based on high level construction trends for utility scale renewable energy projects over recent years, with a small uplift in share made for the period to 2030.
	• $100 represents the grid connection cost per kW of installed renewable energy.
Electrolyser	• 100 MW of electrolyser capacity will be required to support theProject. • Construction cost per MW of electrolyser capacity is estimatedat $1,700,000. • By 2030 it is assumed the electrolyser manufacturing industry will have been sufficiently established to service domestic markets. It is further assumed that 40% of construction investment for electrolysers will flow to South Australia, 20% will flow interstate and 40% will be associated with imports. • $22,000 is the cost to construct a Reverse Osmosis Desalination Plant to provide the required water (28,500ML/year) to the electrolysers.
Long-term Storage	• Not required for 10% hydrogen.

Assumption	Parameter
Distribution	• Not required for 10% hydrogen.
Operation	
Electricity generation	• Annual operational and maintenance cost per MW of renewable energy is estimated at $17,000.
Electrolyser	• Annual operational and maintenance cost per MW is estimated at $54,000.
	• 600 ML p.a. of additional water will be required for electrolysers.
	• Water cost per tonne of hydrogen is estimated at $14.
Short-term storage	• No new operational costs assumed.
Distribution	• No new operational costs assumed.

Note: financial parameters are expressed in constant 2021 AUD$.

Construction and Operational Analysis

For 10% hydrogen, several additional infrastructure investments would be required in key areas of the hydrogen supply chain, such as renewable electricity generation, hydrogen production and storage.

According to the EIA's key assumptions and parameters outlined in Table 18, the total construction costs required to achieve the 10% Hydrogen Blending Scenario for South Australia is estimated to be approximately $223.58 million (in 2021 dollars).

This cost would be spent evenly over the estimated five-year construction period from 2025 to 2030, which equates to an approximate spend of $44.72 million per annum.

Table 19 outlines the estimated construction costs, and the jurisdiction where this expenditure is expected to occur, with reference to the recommended infrastructure investments across each stage of the hydrogen supply chain.

Table 36: Estimated total construction costs - 10% hydrogen by 2030

Stage of hydrogen supply chain	**Construction costs** ($m)		
	Domestic		Imports
	South Australia	Rest of Australia	
Electricity generation	$23.22	$5.06	$25.28
Electrolyser	$68.02	$34.00	$68.00
Short-term (intra-day) storage	-	-	-
Distribution	-	-	-
Sub total	$91.24	$39.06	$93.28
Total	**$223.58**		

The EIA recommended that once construction was completed, ongoing operational and maintenance costs would be incurred. Table 20 outlines the estimated costs.

Table 37: Estimates operational and maintenance costs - 10% hydrogen by 2030

State of hydrogen supply chain	**Operational costs** ($m)
Electricity Generation	$0.51
Electrolyser (including water supply)	$5.40
Short-term Storage	-
Distribution	-
Total	**~$5.91**

The operational and maintenance cost estimates were calculated utilising a range of current industry benchmarks. These estimates would be expected to change over time as a result of technology improvements and as further details of the operational parameters of 10% hydrogen were developed.