INDICATIVE ANALYSIS OF BLENDING HYDROGEN IN GAS NETWORKS – UPDATE

A REPORT FOR THE DEPARTMENT OF INDUSTRY, SCIENCE, ENERGY AND RESOURCES

11 MAY 2020
Indicative analysis of blending hydrogen in gas networks

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EXECUTIVE SUMMARY

The scope of our engagement

Frontier Economics has been engaged by the Commonwealth Department of the Environment and Energy (now Industry, Science, Energy and Resources) (the Department) to undertake an indicative analysis of the economics of blending hydrogen in Australian natural gas distribution networks. Our analysis is limited to a specific gas distribution network servicing urban areas of Melbourne.

We have investigated the economics of blending hydrogen in a natural gas distribution network by examining a number of energy supply options, including options that involve blending hydrogen. While we consider that these cases we have examined are useful for understanding the economics of hydrogen blending at low rates in Victoria, and for understanding the factors that are likely to drive the economics of blending at higher rates or in other regions, it cannot be assumed that the results we find for the cases we investigate will necessarily apply in other regions or for blending at other rates. This report should be read as an assessment of the specific cases we have investigated and our findings cannot necessarily be extended to other cases (such as other locations or other rates of blending).

The energy supply options that we assessed

For the purposes of our analysis we have assumed that hydrogen blending occurs in Australian Gas Networks’ (AGN’s) distribution network in Victoria. In our view, AGN’s distribution network in Victoria offers a number of locations that would be suitable for injection of hydrogen produced using an electrolyser; specifically, there are a number of existing metered injection points on AGN’s distribution network that are located in reasonable proximity to existing electricity transmission lines (and existing generation plant).

We have assessed the costs and benefits of four energy supply options. We have compared the outcomes for these four options against outcomes in a Base Case, which represents business-as-usual outcomes in the electricity supply chain and the natural gas supply chain. The four energy supply options that we have assessed are the following:

1. **Hydrogen Blending Option** – under this energy supply option hydrogen is blended with natural gas in AGN’s distribution network to 10% by volume. Blending of hydrogen and natural gas occurs to ensure that the energy content of the blended gas is equal to the energy content of natural gas in the Base Case (this implies displacement of 3.17% of gas by energy content). Hydrogen is produced using an electrolyser and can be stored underground in depleted gas fields to meet seasonal fluctuations in energy demand.

2. **Hydrogen Blending Option with Pipeline Storage** – this energy supply option is the same as the Hydrogen Blending Option, but we assume that the only available hydrogen storage option is storage of hydrogen in pipelines as linepack. Storing hydrogen as linepack is substantially more expensive than underground storage. We examine this case given the uncertainty of the feasibility and economics of underground hydrogen storage in Victoria.

3. **Hydrogen Blending Option no Storage** – this energy supply option is the same as the Hydrogen Blending Option but we assume that hydrogen storage is not feasible. We examine this case given the uncertainty of the feasibility and economics of storing hydrogen either underground or as linepack in Victoria.
4. Electricity Switching Option – under this energy supply option the same amount of natural gas is displaced from AGN’s natural gas distribution network as in the Hydrogen Blending Options, but the displacement of gas is due to customers switching from gas supply to electricity supply.

For each of these four energy supply options we examine two cases for the commencement of the change to energy supply: the first case has blending or electricity switching (depending on the option) occurring from the commencement of financial year 2025; the second case has blending or electricity switching (depending on the option) occurring from the commencement of financial year 2030.

A high level comparison of these energy supply options is provided in Table 1.

**Our results**

A comparison of the results for these energy supply options is provided in Table 1. The results that are presented in Table 1 are the present value of the net benefit for each option (relative to the Base Case). The fact that the present value of the net benefit for each option is negative indicates that the present value of the costs under each option is higher than the present value of the costs under the Base Case. The incremental costs that are accounted for in the net present values in Table 1 include all the costs that are quantified in this report. Depending on the scenario, these costs can include changes in:

- electricity generation and storage costs
- electricity transmission and distribution costs
- gas production costs
- gas transmission costs
- hydrogen production costs
- hydrogen storage costs.

To account for the fact that for each of the four energy supply options we examine one case with the change commencing in 2025 and a second case with the change commencing in 2030, the net present value of the incremental costs are presented for two time periods: for the full modelling period from 2020 to 2050; and for the period from 2030 to 2050, on the basis that over this period all cases have equivalent gas displacement.

Based on our assessment of outcomes under the four energy supply options, we reach a number of conclusions:

- **The Base Case is the lowest cost option** – as seen in Table 1, the present value of the net benefit of each of the four energy supply options is negative, regardless of whether we assess the present value over the full modelling from 2020 to 2050 or over the period from 2030 to 2050. The reason for this is that each of the four energy supply options entails an incremental increase in costs relative to the Base Case.

Measured over the period from 2030 to 2050, the present value of the incremental costs is between:

- $101 million for the Electricity Switching Option (2025). This is based on incremental annual costs of between $17 million and $34 million each year (in real dollars).
- $165 million for the Hydrogen Blending Option no Storage (2030). This is based on incremental annual costs of between $16 million and $41 million each year (in real dollars).
To put these incremental annual costs in context, we estimate that the annual cost of gas supplied on AGN’s distribution network in Victoria was approximately $550 million in 2019.¹

- Of the gas displacement options, the lowest cost depends on when the gas displacement commences:
  - For the cases in which gas displacement commences in 2025, the Electricity Switching Option is the lowest cost – as seen in Table 1, the present value of the net benefit of the Electricity Switching Option (2025) is negative by the smallest amount.
  - For the cases in which gas displacement commences in 2030, the Hydrogen Blending Option is the lowest cost – as seen in Table 1, the present value of the net benefit of the Hydrogen Blending Option (2030) is negative by the smallest amount.

This is because the state of the electricity market is a key driver of incremental costs in the Electricity Switching Option. In particular, our modelling finds that the retirement of one or more units of Yallourn could be deferred (relative to the Base Case) if there is higher electricity demand, meaning that the higher electricity demand can make use of lower-cost, committed generation capacity. This is of particular benefit for the Electricity Switching Option, for which the increase in both peak electricity demand and, more generally, electricity consumption during high demand times, is higher than it is in the Hydrogen Blending Option. In the 2030 options, this benefit is reduced, since by 2030 the potential to meet higher demand by making use of existing generation capacity is less.

In the long term, the Hydrogen Blending Option has lower costs; a key reason for this is that the ability of the electrolyser to operate at times of low electricity prices (and low demand and/or high supply) means that the increase in electricity sector costs in the Hydrogen Blending Options are lower than they are in the Electricity Switching Options.

- Hydrogen options with no storage (or high cost storage) are significantly higher cost – as seen in Table 1, the Hydrogen Blending Option with Pipeline Storage and the Hydrogen Blending Option no Storage are both significantly higher cost than the other options for gas displacement. The reason is that the absence of storage means:
  - More hydrogen production capacity is needed to meet peak demand on AGN’s distribution network.
  - There is less opportunity to produce hydrogen at times of low electricity prices.

¹ This cost estimate is the sum of the smoothed allowed revenue for AGN’s distribution network in Victoria in 2019 ($224 million) and the estimated cost of the wholesale gas supplied on AGN’s distribution network in 2019 (calculated as the quantity of gas forecast to be supplied on the network in 2019 – 36.4 PJ – multiplied by the average price of gas on the Victorian Declared Wholesale Gas Market in 2019 – $8.75/GJ).
Table 1: Summary of energy supply options – assumptions and results

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<tr>
<th>ENERGY SUPPLY OPTION</th>
<th>GAS DISTRIBUTION NETWORK</th>
<th>GAS DISPLACEMENT COMMENCING</th>
<th>GAS QUANTITY DISPLACED</th>
<th>ALTERNATE FUEL</th>
<th>HYDROGEN STORAGE OPTION</th>
<th>PV OF NET BENEFIT AGAINST BASE CASE (2020 TO 2030)</th>
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<td>Base Case</td>
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<td><strong>2025 options</strong></td>
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<td>Hydrogen Blending Option</td>
<td>AGN</td>
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<td>-$160 million</td>
<td>-$107 million</td>
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What is driving these results?

Our analysis of incremental costs under the four energy supply options we examine indicate that the following factors are important to the results:

- **The timing of demand for additional electricity affects electricity generation costs.** Incremental costs of electricity generation account for a large proportion of the additional costs for each energy supply option: in the Electricity Switching Option incremental costs of electricity generation generally account for between 60% and 80% of all incremental costs (with the rest made up of electricity transmission and distribution costs), and in the Hydrogen Switching Options the incremental costs of electricity supply generally account for between 65% and 75% of total incremental costs (with the rest made up of the cost of hydrogen production and storage). The magnitude of these incremental costs of electricity generation is affected by the timing of this additional demand. Our electricity market modelling indicates that the average cost of additional electricity to operate the electrolyser in the Hydrogen Blending Option is about $30/MWh cheaper than the average cost of additional electricity to enable switching in the Electricity Switching Option. This is because in the Hydrogen Blending Option the electrolyser can operate at times when additional electricity is low cost, while in the Electricity Switching Option additional electricity is required at the times that customers currently use gas.

- **The availability of low-cost electricity generation changes costs over time.** Where there is additional electricity generation capacity (for instance, as a result of renewable schemes driving renewable investment that is not required to meet electricity demand) the cost of additional electricity generation can be low. This is a key reason for our modelling finding that the Electricity Switching Option is lower cost for the 2025 case but not for the 2030 case; during the 2020s our electricity market modelling finds that there is little difference in the cost of additional electricity demand between the Electricity Switching Option and the Hydrogen Blending Options, contributing to the Electricity Switching Option being lower cost overall.

- **The timing of demand for additional electricity affects electricity transmission costs.** We assume that there will not be additional costs to the electricity transmission network under the Hydrogen Blending Options because the electrolyser will have enough intra-day or intra-year flexibility to be able to avoid operating at times of peak demand on the transmission network. In contrast, under the Electricity Switching Option we assume that there will be additional costs to the electricity transmission network to reflect the calculated increase in peak demand by customers using electricity instead of gas.

- **The availability of hydrogen storage affects when electricity is used in hydrogen production.** As discussed, in the Hydrogen Blending Option – in which we assume that underground hydrogen storage is available – the electrolyser is able to operate much more flexibly in order to take advantage of times when the cost of additional electricity generation is low. Where hydrogen storage is expensive, or unavailable, this flexibility is diminished. The result is that the average cost of additional electricity generation in the options in which hydrogen storage is expensive or unavailable is about $15/MWh more expensive than under the Hydrogen Blending Option (that is, it falls about mid-way between the average cost of additional electricity generation in the Hydrogen Blending Option and the Electricity Switching Option). We assume, however, that even where hydrogen storage is expensive or unavailable the electrolyser will have enough intra-day operational flexibility to ensure that it does not operate at times of peak demand on the electricity transmission network (and so does not add to transmission network costs).

- **Different supply options entail some different categories of incremental costs.** All of the options that we have considered entail additional costs of wholesale electricity, as we discuss above. Beyond that, there are differences in the categories of incremental costs. The Hydrogen Blending Options entail additional capital and operating costs of hydrogen production and storage. The Electricity Switching Option entails additional capital and operating costs of electricity transmission (because times of peak demand cannot be avoided under the Electricity Switching Option) and of electricity
distribution (because additional electricity needs to be delivered to final customers, and because times of peak demand cannot be avoided). How the costs of hydrogen production and storage capacity compare with the costs of augmenting the electricity network is an important driver of the relative cost of the hydrogen blending compared with electricity switching.

• **Technology cost curves affect costs over time.** The estimates of hydrogen production costs that we use – sourced from the IEA – have capital costs that decline materially over time and efficiency that increases over time (presumably reflecting the fact that large-scale electrolysers are a new technology). The result of this is that the incremental cost of hydrogen production is lower for the case in which hydrogen blending commences in 2030 than the case in which hydrogen blending commences in 2025.

• **Avoided gas sector costs are the same under all options.** Since, by design, under each option we are avoiding the same amount of total gas consumption, and at the same times of the year, the avoided gas sector costs are the same under all options.

### Assumptions and limitations

Of course, our modelling and our estimates of costs and benefits are based on a range of input assumptions, particularly input assumptions about the costs of supplying and transporting electricity, natural gas and hydrogen. While this is an inevitable feature of modelling of this kind it is worth bearing in mind that our results will vary according to these assumptions. Particularly in developing industries – such as the hydrogen industry – there is significant uncertainty about long-term costs.

We also emphasise that we have investigated a number of specific cases relating to blending hydrogen in a natural gas distribution network. The specific cases that we have investigated:

• relate to blending hydrogen in a natural gas distribution network to a volume of 10%, or displacing the equivalent amount of natural gas by electricity switching

• assume that the blending or switching would commence in 2025 and 2030 and the blending would not increase above 10% by volume over the modelling period

• assume that blending occurs at a constant rate of 10% by volume

• assume that the blending will occur in Australian Gas Networks’ (AGN’s) distribution network in Victoria

• are based on a single set of business-as-usual assumptions for electricity and gas markets.
1 INTRODUCTION

Frontier Economics has been engaged by the Commonwealth Department of the Environment and Energy (now Industry, Science, Energy and Resources) (the Department) to undertake indicative analysis of the economics of blending hydrogen in Australian natural gas distribution networks.

1.1 Background

In December 2018, the Council of Australian Governments (COAG) Energy Council committed to a vision of making Australia a major player in a global hydrogen industry by 2030.

COAG Energy Council approved a high-level work plan and established the Hydrogen Working Group (comprising the National Hydrogen Strategy Steering Committee and taskforce). The work streams to be undertaken by the Hydrogen Working Group are as follows:

- Developing a hydrogen export industry
- Hydrogen in the gas network
- Hydrogen for transport
- Hydrogen to support electricity systems
- Hydrogen for industrial users; and
- Cross-cutting issues, including standards, regulation and labelling, research and innovation, safety and community engagement, governance, and hydrogen precincts and cities.

To support the work stream on hydrogen in the gas network, a high-level economic analysis is required of scenarios involving hydrogen blending in an existing Victoria gas distribution network for use by existing domestic and industrial users. The Department has engaged Frontier Economics to undertake this high-level economic analysis.

1.2 Frontier Economics’ engagement

Frontier Economics was originally engaged by the Department to undertake indicative analysis of the economics of blending hydrogen into Australian gas distribution networks. We were engaged to consider the expected costs and benefits of the introduction of hydrogen to 10% by volume into an Australian gas distribution network (with a focus on a Victorian urban network), and to consider how these costs and benefits change depending on the timeframes over which blending occurs. Factors to be considered in our analysis included:

- The cost of electricity generation to produce and supply hydrogen. This will include the cost of additional renewable generation over and above “business as usual” renewable generation.
- The cost of electricity distribution networks and/or transmission lines.
- The cost of gas distribution networks and/or transmission pipelines.

Our analysis only includes known direct supply chain costs and benefits of the energy supply options outlined we investigate. While there are potential indirect costs and benefits from hydrogen blending, including energy security, emissions reduction, end user appliance switching or developing a hydrogen sector in Australia, these were not included in the analysis.
Our analysis assumed that initial blending of up to 10% by volume is to be done with a longer-term view to complete fuel substitution – given that key actions required to accommodate lower blends up to 10% will be to make the network “hydrogen ready”.

In line with the National Hydrogen Strategy, our analysis considered the introduction of hydrogen blending in 2025 and 2030.

In order to present the economics of embarking on the introduction of hydrogen use as a means of decarbonising the heat demand currently being met by natural gas, an analysis of the alternate scenario of electrification was required. This alternate case was for the purposes of comparison with the 10% hydrogen pathway from 2025 and 2030, presenting a high-level analysis of the costs to electrify the heat demand met by hydrogen under the hydrogen blending cases.

We provided a report to the Department in October 2019 setting out the results of this indicative analysis.²

We have now been engaged by the Department to update the indicative analysis that we undertook in 2019. Specifically, we are to update our indicative analysis to account for the following:

- To make use of the Integrated System Plan (ISP) input assumptions released by AEMO since the indicative analysis that we undertook in 2019. This input assumptions are summarised in Appendix A.
- To model two additional scenarios that incorporate hydrogen storage as linepack in gas pipelines.

1.3 About this report

This report is an update of the report that we provided to the Department in October 2019. This report is structured in the same way as our October 2019 report, as follows:

- Section 2 provides some background of blending hydrogen into the natural gas distribution network.
- Section 3 describes the energy supply options that we are assessing and sets out the likely impacts on the gas sector, electricity sector and hydrogen sector of these energy supply options.
- Section 4 describes our methodology.
- Section 5 presents our results.
- Section 6 provides our conclusions.

Given that this report is intended to provide an indicative analysis of the economics of blending hydrogen in Australian natural gas distribution networks, and that this project has been undertaken within a short timeframe, we have not undertaken partial equilibrium modelling of each sector that is affected by the cases that we are assessing. Rather, we have focused on undertaking partial equilibrium modelling of the sectors in which we would expect the most material differences in costs: the electricity generation sector and the hydrogen production sector. For other sectors we have assessed costs and benefits according to high level estimates of levelised costs or long run marginal costs.

We also note that our modelling and our estimates of costs and benefits are based on a range of input assumptions, particularly input assumptions about the costs of supplying and transporting electricity, natural gas and hydrogen. While this is an inevitable feature of modelling of this kind it is worth bearing in mind that our results will vary according to these assumptions. Particularly in developing industries – such as the hydrogen industry – there is significant uncertainty about long-term costs.

Finally, we note that we have investigated a number of specific cases relating to blending hydrogen in a natural gas distribution network. The specific cases that we have investigated:

- relate to blending hydrogen in a natural gas distribution network to a volume of 10%, or displacing the equivalent amount of natural gas by electricity switching
- assume that the blending or switching would commence in 2025 and 2030 and the blending would not increase above 10% by volume over the modelling period
- assume that the blending will occur in Australian Gas Networks’ (AGN’s) distribution network in Victoria
- are based on a single set of business-as-usual assumptions for electricity and gas markets.

While we consider that these cases are useful for understanding the economics of hydrogen blending at low rates in Victoria, and for understanding the factors that are likely to drive the economics of blending at higher rates or in other regions, it cannot be assumed that the results we find for the cases we investigate will necessarily apply in other regions or for blending at other rates. This report should be read as an assessment of the specific cases we have investigated and our findings cannot necessarily be extended to other cases (such as other locations or other rates of blending).
2 BACKGROUND TO BLENDING HYDROGEN IN AUSTRALIAN NATURAL GAS DISTRIBUTION NETWORKS

Hydrogen is a combustible gas that can be used in similar ways to natural gas. Pipeline networks could supply customers with 100% hydrogen or hydrogen could be blended with natural gas and supplied to customers.

This study is focused on the economic costs and benefits of blending hydrogen with natural gas for distribution in an existing distribution network in Victoria. This section provides an overview of the issues associated with blending hydrogen gas with natural gas.

2.1 Blending hydrogen with natural gas

There is global interest in investigating opportunities to blend hydrogen with natural gas in existing gas distribution networks.

Research and trials investigating the use of the gas network to supply hydrogen are underway in Australia and overseas. Most relevantly to our study:

- In New South Wales, Jemena Gas Networks is exploring a pilot project to demonstrate large-scale renewable energy storage and distribution on its existing gas pipeline infrastructure. Under the trial, a 500 kW electrolyser will be used to produce hydrogen, which will be injected into Jemena’s gas grid.\(^3\)

- In South Australia, Australian Gas Infrastructure Group (AGIG) is undertaking a project to produce hydrogen from a 1.25 MW electrolyser at Tonsley Innovation District in Adelaide, for injection (at up to 15%) into the local gas distribution network.\(^4\)

- In France, Engie is trialling the injection of hydrogen into the natural gas distribution network of a new neighbourhood, as part of the GRYHD demonstration project. An electrolyser will be used to produce hydrogen that will be injected into the gas distribution network at variable rates up to 20%.\(^5\)

- In the United Kingdom HyDeploy @ Keele involves a live trial of blending hydrogen into a natural gas network on part of the private gas network at Keele University in Staffordshire. A trial of blending hydrogen up to 20% commenced early in 2020. Under the trial, a 500 kW electrolyser is used to produce hydrogen.

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• In Germany, the Energiepark Mainz project has a 6 MW electrolysis hydrogen production unit. The electrolyser is connected to the local electricity network and produces hydrogen for injection into the local gas grid as well as a multi-use filling station. The facility has been in operation since 2017.

Other trials are looking at using 100% hydrogen in the distribution network. For instance, the H21 Leeds City Gate feasibility study investigated the technical and economic feasibility of converting the Leeds gas supply to hydrogen. This study confirmed that converting the gas network to 100% hydrogen is both technically possible and could be delivered at a realistic cost.6

2.2 Differences between hydrogen and natural gas

Hydrogen and natural gas have different characteristics, which may pose issues for blending hydrogen and natural gas in existing gas distribution networks.

Relevant physical properties of hydrogen are set out in Figure 1.

Figure 1: Physical properties of hydrogen

<table>
<thead>
<tr>
<th>Property</th>
<th>Hydrogen</th>
<th>Comparison</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (gaseous)</td>
<td>0.089 kg/m³ (0°C, 1 bar)</td>
<td>1/10 of natural gas</td>
</tr>
<tr>
<td>Density (liquid)</td>
<td>70.79 kg/m³ (-253°C, 1 bar)</td>
<td>1/6 of natural gas</td>
</tr>
<tr>
<td>Boiling point</td>
<td>-252.76°C (1 bar)</td>
<td>90°C below LNG</td>
</tr>
<tr>
<td>Energy per unit of mass (LHV)</td>
<td>120.1 MJ/kg</td>
<td>3x that of gasoline</td>
</tr>
<tr>
<td>Energy density (ambient cond., LHV)</td>
<td>0.01 MJ/L</td>
<td>1/3 of natural gas</td>
</tr>
<tr>
<td>Specific energy (liquefied, LHV)</td>
<td>8.5 MJ/L</td>
<td>1/3 of LNG</td>
</tr>
<tr>
<td>Flame velocity</td>
<td>346 cm/s</td>
<td>8x methane</td>
</tr>
<tr>
<td>Ignition range</td>
<td>4–77% in air by volume</td>
<td>6x wider than methane</td>
</tr>
<tr>
<td>Autoignition temperature</td>
<td>585°C</td>
<td>220°C for gasoline</td>
</tr>
<tr>
<td>Ignition energy</td>
<td>0.02 MJ</td>
<td>1/10 of methane</td>
</tr>
</tbody>
</table>

Source: IEA, The Future of Hydrogen; Seizing today’s opportunities, Report prepared by the IEA for the G20, Japan, June 2019

Some of the key implications of these physical properties for the use of hydrogen in the natural gas distribution network are as follows:

• While hydrogen contains more energy per unit of mass than natural gas or gasoline, hydrogen is lighter than natural gas or gasoline and so has a lower energy density per unit of volume. This means that a greater volume of hydrogen would need to be delivered through a pipeline network to provide a given quantity of energy than is the case for natural gas. However, hydrogen flows more quickly through a pipeline for a given pressure difference, which compensates for the different volume of hydrogen.

• Because metering in Australia’s natural gas network is based on the flow rate of gas, differences between the energy content of blended gas and natural gas will require changes in metering or changes in billing systems.

• Because of differences in the flame velocity and emissivity between hydrogen and natural gas, changes to the design of valves and burners are likely to be required at some point on the transition

6 HyDeploy website: https://hydeploy.co.uk/
to 100% hydrogen gas. However, studies suggest that conventional residential appliances can operate without upgrades with a concentration of hydrogen up to 20% by volume.

- Because hydrogen is odourless and is not visible when burning, odourants and flame enhancement additives are likely to be needed.
- Because hydrogen is more mobile than natural gas in many polymer materials, leakage rates for hydrogen in distribution systems is expected to be materially higher than leakage rates for natural gas. While estimates suggest that the increase in leakage will be economically insignificant, it has the potential to increase safety concerns and may increase the need for additional detection and monitoring devices.

There is also the potential for pipeline embrittlement to occur as a result of transport of 100% hydrogen in high pressure steel pipelines. However, these issues do not arise to the same extent for distribution networks where pressures are lower and pipeline materials tend to be different.

### 2.3 Producing hydrogen

There are a number of methods for producing hydrogen.

Hydrogen can be produced **electrochemically**, which involves using electricity to dissociate water into hydrogen and oxygen through a process known as electrolysis. Less than 0.1% of hydrogen production globally currently comes from electrolysis.

Hydrogen can be produced **thermochemically**, which involves using a fossil fuel or biomass feedstock to produce hydrogen. This is the most common approach to producing hydrogen today, with natural gas most commonly used as a feedstock for a steam methane reformer.

These pathways for producing hydrogen (and subsequently converting hydrogen into either ammonia or synthetic hydrocarbons) are summarised in **Figure 2**.

**Figure 2**: Pathways for producing hydrogen and hydrogen-based products

[Diagram showing pathways for producing hydrogen and hydrogen-based products]

*Source: IEA, the Future of Hydrogen; Seizing today’s opportunities, Report prepared by the IEA for the G20, Japan, June 2019.*

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For the purposes of this study, in the scenarios that we model, we assume that hydrogen will be produced using electrolysis rather than being produced thermochemically. There are three reasons for this:

- Natural gas prices in eastern Australia are currently very high, and most market observers – including AEMO – expect these high prices to persist. This makes thermochemical production of hydrogen in eastern Australia economically challenging. In contrast, high rates of renewable generation raise the prospect that low cost electricity will be available for electrolysis.

- Natural gas supply to the domestic market in eastern Australia remains tight. Over recent years the ACCC has reported that large gas users have faced difficulties securing long-term gas supply contracts. While the ACCC report that there has been some recent improvement in this regard, with uncertainty remaining about all prospects for delivering additional gas to the domestic market in eastern Australia, there remains significant uncertainty about the extent to which domestic gas users will be able to secure long-term supply.

- Without carbon capture and storage, producing hydrogen thermochemically results in significant carbon emissions. Whether or not investors face a direct cost for these emissions, investors in long-lived assets like hydrogen production facilities are likely to be concerned about their long-term exposure to carbon risk. Electrolysis using renewable electricity does not pose this same risk.

If it turns out that natural gas supply to the domestic market is greater than expected, and natural gas prices are lower than forecast, then it may be the case that thermochemical production of hydrogen turns out to be the preferred approach for producing hydrogen for blending. And, if it is economic to do so, carbon capture and storage can be used to avoid release into the atmosphere of the carbon emissions produced through thermochemical production of hydrogen. For this reason, we also examine the potential differences in costs and benefits for a case in which thermochemical production turns out to be the preferred technology for producing hydrogen. This is discussed in more detail in Section 5.3.

There are three main electrolysis technologies available today:

- Alkaline electrolysis is a mature technology that has been used at large scale in the past. The component parts are currently produced at scale (since they are the same parts used in commercial manufacture of chlorine and sodium hydroxide). Alkaline electrolysis currently has the lowest capital cost of the available electrolysis technologies. However, alkaline electrolyser have a poor current density (they require a large footprint) and produce low pressure hydrogen.

- Proton exchange membrane (PEM) electrolyser are a newer technology designed to address some of the drawbacks of alkaline electrolysis. PEM electrolyser are smaller and more flexible than alkaline electrolyser, and produce higher pressure hydrogen. However, PEM electrolyser currently have higher capital costs than alkaline electrolyser.

- Solid oxide electrolysis cells (SOEC) are the least developed technology and have not yet been commercialised. SOEC use ceramics as the electrolyte and have low material costs, and also have a high degree of electrical efficiency. However, SOEC currently have the highest capital cost.

For the purposes of this study we assume that hydrogen will be produced using alkaline electrolysis. The reason for this is that the assumptions that we use for the capital and operating costs of electrolyser (as discussed in Section 4.1) suggests that alkaline electrolyser will remain lower cost than the alternatives in both 2025 and 2030 and, additionally, alkaline electrolyser are more efficient than PEM electrolyser.
3 IMPACTS OF ENERGY SUPPLY OPTIONS

In order to identify the costs and benefits of the energy supply options that we are investigating it is useful to first map the impacts of each of these options on each stage of the relevant energy supply chain.

This section defines the energy supply options we are investigating and maps the direct impacts of these options on the electricity, gas and hydrogen supply chains. This section also discusses broader impacts of the energy supply options.

3.1 Defining our energy supply options

As part of our original engagement by the Department, the energy supply options that we were engaged to assess were the following:

- Hydrogen Blending Option – under this energy supply option, hydrogen is blended with natural gas in the natural gas distribution network to 10% by volume. Blending occurs to ensure that the energy content of the blended gas is equal to the energy content of natural gas in the Base Case. We examine two cases for the timing of hydrogen blending: blending occurs from the commencement of financial year 2025 and blending occurs from the commencement of financial year 2030. We have assumed that blending occurs in Australian Gas Networks’ (AGN’s) distribution network in Victoria. In our view, AGN’s distribution network in Victoria offers a number of locations where existing metered injection points on the gas distribution network are located in reasonable proximity to existing electricity transmission lines and existing generation plant. This is discussed in more detail in Appendix B.

- Hydrogen Blending Option no Storage – this option is the same as the Hydrogen Blending Option but we assume that hydrogen storage is not feasible. We examine this case given the uncertainty of the feasibility and economics of underground hydrogen storage in Victoria. We examine the same two cases for the timing of hydrogen blending: blending occurs from the commencement of financial year 2025 and blending occurs from the commencement of financial year 2030.

- Electricity Switching Option – under this energy supply option, the same amount of natural gas is displaced from AGN’s natural gas distribution network as in the Hydrogen Blending Options, but the displacement of gas is due to customers switching from gas supply to electricity supply. We examine the same two cases for the timing of electricity switching: switching occurs from the commencement of financial year 2025 and switching occurs from the commencement of financial year 2030.

For this updated analysis we update our assessment of each of these options, including each timing variant of the options. In addition, we examine a fourth energy supply option:

- Hydrogen Blending Option with Pipeline Storage – this option is the same as the Hydrogen Blending Option but we assume that the only available hydrogen storage option is storage of hydrogen as linepack. As discussed in Section 4 storing hydrogen as linepack is substantially more expensive than underground hydrogen storage. Like the Hydrogen Blending Option no Storage option, this option is examined given the uncertainty of the feasibility and economics of underground hydrogen storage in Victoria.

We compare outcomes for these four energy supply options – including each timing variant of the options – against outcomes in a Base Case. The Base Case represents business-as-usual outcomes in the electricity supply chain and the natural gas supply chain.
3.2 Base Case energy supply

**Figure 3** provides a depiction of the energy supply to customers connected to AGN’s Victorian gas distribution network. All customers connected to a gas distribution network will also be connected to the electricity network; these customers will meet their energy needs using a combination of electricity supply and gas supply.

The physical supply chain for the supply of electricity to customers consists of the generation and storage of electricity, the transport of electricity from generators to local distribution networks using long-distance high-voltage transmission lines, and the local distribution of electricity to customers.

The physical supply chain for the supply of natural gas to customers consists of the production and storage of natural gas, the transport of gas from production and storage facilities to local distribution networks using long-distance high-pressure transmission pipelines, and the local distribution of gas to customers.

**Figure 3**: Energy supply to end customers – Base Case

![Diagram of energy supply to end customers – Base Case](source: Frontier Economics)

3.3 Hydrogen Blending Options – energy supply and impacts

The Hydrogen Blending Options bring about some changes to the energy supply to affected customers. **Figure 4** provides a depiction of the energy supply to customers connected to AGN’s Victorian gas distribution network under the Hydrogen Blending Options.

There are two important changes under the Hydrogen Blending Options:

- Hydrogen gas is produced and blended into the natural gas distribution network, displacing some natural gas.
- Electricity is supplied to the electrolyser, increasing the demand for electricity.
Figure 4: Energy supply to end customers – Hydrogen Blending Options

![Diagram showing energy supply to end customers with hydrogen blending options]

Source: Frontier Economics

Figure 5, Figure 6 and Figure 7 highlight the impacts – and corresponding direct supply chain costs and benefits – of the changes in energy supply arrangements in the Hydrogen Blending Options on the electricity supply sector, the gas supply sector and the hydrogen supply sector, respectively.

For the electricity supply sector, the production of hydrogen using the electrolyser leads to an increase in electricity generation. Depending on the timing of the operation of the electrolyser this could also lead to a change in the storage of electricity – it may be that the electrolyser operates at times when there is surplus electricity that would be stored in the Base Case. These changes in electricity generation and storage would be expected to result in an increase in the total costs of generation and storage, driven both by an increase in fuel and operating costs and a potential increase in generation capacity. Depending on the location of the electrolyser relative to generators, there may also be the need to transport additional electricity on the transmission network, which may lead to an increase transmission costs.

For the natural gas supply sector, the blending of hydrogen into the natural gas distribution network results in reduced production and transmission of natural gas. These reductions in gas production and transmission would be expected to result in a decrease in the total costs of gas production and transport, driven by both a decrease in operating and capital costs. For the gas distribution network, the blending of hydrogen gas with natural gas could result in changes to the costs of operating the distribution network due to the different physical characteristics of hydrogen gas. For gas customers, the blending of hydrogen gas with natural gas could result in additional costs as a result of the need to retrofit existing appliances to burn blended gas.

For the hydrogen supply sector, the need to produce hydrogen for blending requires the construction and operation of the electrolyser. There will be additional capital and operating costs associated with the electrolyser (the additional costs of electricity used for electrolysis are accounted for by the changes in the costs of the electricity supply sector). There may also be additional capital and operating costs associated with storage of hydrogen (either in underground storage or as pipeline linepack) if storage is feasible and economic.
Figure 5: Electricity sector impacts – Hydrogen Blending Options

Figure 6: Gas sector impacts – Hydrogen Blending Options

Source: Frontier Economics
3.4 Electricity Switching Option – energy supply and impacts

The Electricity Switching Option brings about some changes to the energy supply to affected customers. **Figure 8** provides a depiction of the energy supply to customers connected to AGN’s Victorian gas distribution network under the Electricity Switching Option.

There are two important changes under the Electricity Switching Option:

- Switching from gas to electricity appliances reduces the need to produce and transport natural gas.
- Switching from gas to electricity appliances increases the need to generate and transport electricity.
Figure 8: Energy supply to end customers – Electricity Switching Option

Source: Frontier Economics

Figure 9 and Figure 10 highlight the impacts – and corresponding direct supply chain costs and benefits – of the changes in energy supply arrangements in the Electricity Switching Option on the electricity supply sector and the gas supply sector, respectively.

For the electricity supply sector, switching from gas appliances to electric appliances leads to an increase in the generation, transmission and distribution of electricity. Depending on the timing of the increase in demand for electricity this could also lead to a change in the storage of electricity. These changes in electricity generation and transport would be expected to result in an increase in the total costs of generation and transport, driven both by an increase in fuel and operating costs and a likely increase in generation capacity and transport.

For the natural gas supply sector, switching from gas appliances to electric appliances results in reduced production, transmission and distribution of natural gas. These reductions in gas production and transport may result in a decrease in the total costs of gas production and transport, driven by both a decrease in operation and capital costs.

For customers, switching from gas appliances to electric appliances could result in additional appliance costs.
Figure 9: Electricity sector impacts – Electricity Switching Option

Source: Frontier Economics

Figure 10: Gas sector impacts – Electricity Switching Option

Source: Frontier Economics
4 METHODOLOGY

This section describes the methodology that we have adopted for estimating the direct supply chain costs and benefits of the energy supply options that we are investigating:

- The first step is to estimate changes in natural gas consumption, electricity consumption and hydrogen consumption in the energy supply options that we investigate. Our approach is discussed in Section 4.1.
- Based on estimated changes in natural gas consumption, we can estimate changes in the costs of producing and transporting natural gas. Our approach is discussed in Section 4.2.
- Based on estimated changes in electricity consumption, we can estimate changes in the costs of producing, storing and transporting electricity. Our approach is discussed in Section 4.3.
- Based on estimated changes in hydrogen consumption, we can estimate changes in the costs of producing and storing hydrogen. Our approach is discussed in Section 4.4.

4.1 Changes in natural gas, hydrogen and electricity consumption

Changes in natural gas consumption

The starting point for estimating changes in natural gas consumption, electricity consumption and hydrogen consumption is to assess the reduction in natural gas consumption. To do this we need forecasts of Base Case natural gas consumption on AGNs Victorian distribution business for the duration of our modelling period. Because the timing of energy supply affects the costs of energy supply, we need these Base Case forecasts to be daily forecasts of natural gas consumption. We develop these daily forecasts of natural gas consumption as follows:

- We begin with a profile for daily gas consumption for a base year. Our view is that the best estimate of a profile for daily gas consumption is historical daily gas consumption; this historical data captures the variability in gas consumption over the course of the year. Because we do not have historical daily gas consumption for AGN’s Victorian distribution business we use historical daily gas consumption for the Victorian Declared Wholesale Gas Market (DWGM) as a proxy for daily gas consumption for AGN’s Victorian distribution business. We use the historical data from financial year 2016/17, because this is the historical data that we use in our electricity market modelling; using the same base year ensures that our base year for our gas and electricity analysis reflects the same weather conditions.
- We scale the daily gas consumption for the DWGM for financial year 2016/17 to match annual gas consumption for AGN’s Victorian distribution business, as reported in AGN’s post tax revenue model submitted to the Australia Energy Regulator. This gives us an estimate of the historical daily gas consumption for AGN’s Victorian distribution network for financial year 2016/17, which is shown in Figure 11.
- We increase the historical daily gas consumption for AGN’s Victorian distribution network for financial year 2017 to account for forecast changes in annual gas consumption over our modelling period. Because we do not have long-term forecasts of annual gas consumption for AGN’s Victorian distribution network we use forecasts of growth in annual gas consumption for Victoria as a whole as a proxy for forecasts of growth in annual gas consumption for AGN’s Victorian distribution network. The forecasts for Victoria that we use are from AEMO’s 2019 GSOF, which are shown in Figure
beyond the end of AEMO’s forecast period we roll out growth in annual gas consumption according to the average annual growth rate over the last five years of AEMO’s forecast period.

**Figure 11:** Estimated daily gas consumption for AGN’s Victorian distribution network for 2017/18

![Daily Gas Consumption Chart](image1)

*Source: Frontier Economics analysis of data from AEMO and AGN*

**Figure 12:** Forecast annual gas consumption for AGN’s Victorian distribution network

![Annual Gas Consumption Chart](image2)

*Source: Frontier Economics analysis of data from AEMO and AGN*

Having developed these daily forecasts of natural gas consumption for the Base Case, we then determine the amount of gas to be displaced from AGN’s natural gas network in order to bring about a

---

8 Because we are interested in forecast growth for AGN’s gas distribution network, when calculating AEMO’s forecasts of growth in annual gas consumption we calculate growth in annual gas consumption excluding gas consumption by gas-fired generators. This reflects the fact that gas-fired generators tend to be connected to the gas transmission network rather than the gas distribution network.
10% blend of hydrogen that delivers that same amount of energy to end users. Our calculation is that to achieve this, 3.17% of natural gas would be displaced from the natural gas network. We assume that this 3.17% of gas displacement occurs throughout the year in proportion to daily Base Case gas consumption (in other words, we assume that blending occurs at a constant rate of 10% by volume), and that this same amount of gas displacement occurs in both the Hydrogen Blending Options and the Electricity Switching Option. This results in the revised daily profile of gas consumption shown in Figure 13, and the revised annual gas consumption shown in Figure 14.

Figure 13: Estimated daily gas consumption for AGN’s Victorian distribution network for 2024/25 – all cases

![Figure 13: Estimated daily gas consumption for AGN’s Victorian distribution network for 2024/25 – all cases](image)

Source: Frontier Economics analysis of data from AEMO and AGN

Figure 14: Forecast annual gas consumption for AGN’s Victorian distribution network – all cases

![Figure 14: Forecast annual gas consumption for AGN’s Victorian distribution network – all cases](image)

Source: Frontier Economics analysis of data from AEMO and AGN
Changes in hydrogen consumption

The amount of gas to be displaced from the natural gas network in order to bring about a 10% blend of hydrogen in the Hydrogen Blending Options implies the amount of hydrogen to be produced to displace this gas. Measured in energy terms, the hydrogen to be produced exactly matches the natural gas displaced. This is shown in Figure 15.

Figure 15: Estimated daily gas and hydrogen consumption for AGN’s Victorian distribution network for 2024/25

Changes in electricity consumption due to hydrogen production

Calculating the amount of electricity required to produce the required amount of hydrogen in the Hydrogen Blending Options requires an optimisation of hydrogen production and hydrogen storage (although we exclude hydrogen storage in the Hydrogen Blending Option no Storage). We undertake this optimisation by calculating the lowest cost means of producing and storing hydrogen in order to provide the required daily profile of hydrogen. This optimisation is based on assumptions about the cost of producing and storing hydrogen, and assumptions about the average daily price of electricity. The assumptions that we use are as follows:

- The assumptions on costs and technical characteristics for hydrogen production using an electrolyser are set out in Table 2. We use these assumptions in each of the Hydrogen Blending Options (the Hydrogen Blending Option, the Hydrogen Blending Option no Storage and the Hydrogen Blending Option with Pipeline Storage).

- The assumptions on costs and technical characteristics for hydrogen storage that are used in the Hydrogen Blending Option are based on storage in depleted gas fields, which is estimated to have lower capital costs than alternate storage technologies. These assumptions are set out in Table 3.

- The assumptions on costs and technical characteristics for hydrogen storage that are used in the Hydrogen Blending Option with Pipeline Storage are based on storage in compressed gas pipelines. These assumptions are based on public data on the cost of building and operating gas pipelines and compressor stations in Australia. These assumptions are set out in Table 4.

- The electricity prices that we use are from our Base Case electricity market modelling.
Table 2: Costs and characteristics of hydrogen production using electrolysis

<table>
<thead>
<tr>
<th></th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production capex ($/kWe)</td>
<td>$1,064</td>
<td>$845</td>
</tr>
<tr>
<td>Production opex (% of capex)</td>
<td>2%</td>
<td>2%</td>
</tr>
<tr>
<td>Production efficiency (%, LHV)</td>
<td>67.25%</td>
<td>68.00%</td>
</tr>
<tr>
<td>Production life (years)</td>
<td>24</td>
<td>27</td>
</tr>
</tbody>
</table>


Table 3: Costs and characteristics of hydrogen storage – depleted gas field

<table>
<thead>
<tr>
<th></th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage capex ($/GJ)</td>
<td>$48.39</td>
<td>$48.39</td>
</tr>
<tr>
<td>Storage opex ($/GJ/a)</td>
<td>$0.18</td>
<td>$0.18</td>
</tr>
<tr>
<td>Storage losses (%)</td>
<td>0.50%</td>
<td>0.50%</td>
</tr>
<tr>
<td>Storage life (years)</td>
<td>30</td>
<td>30</td>
</tr>
</tbody>
</table>


Table 4: Costs and characteristics of hydrogen storage – pipeline storage

<table>
<thead>
<tr>
<th></th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage capex ($/GJ)</td>
<td>$1,600</td>
<td>$1,600</td>
</tr>
<tr>
<td>Storage opex (% of capex)</td>
<td>3%</td>
<td>3%</td>
</tr>
<tr>
<td>Storage losses (%)</td>
<td>0.00%</td>
<td>0.00%</td>
</tr>
<tr>
<td>Storage life (years)</td>
<td>30</td>
<td>30</td>
</tr>
</tbody>
</table>

Source: Frontier Economics.

There is uncertainty about the best hydrogen storage option in Victoria and, therefore, the cost of that storage. There are a number of options for storage of hydrogen, including compression in salt caverns, aquifers or depleted gas fields, compressed pressure vessels, pipeline storage and storage of liquified hydrogen. The costs and technical capabilities of these storage options differ.

For the purposes of the Hydrogen Blending Option we have assumed that storage in depleted gas fields is possible, and have based the costs of storage (as set out in Table 3) on that assumption. Under the Hydrogen Blending Option, our optimisation finds that it is least cost to invest in both hydrogen production and hydrogen storage so that hydrogen can be produced throughout the year at times when electricity prices are at their lowest, and stored hydrogen can then be used to meet the increased demand for hydrogen in the natural gas distribution network during winter. This optimisation implies that...
the increase in electricity consumption for use in the electrolyser will occur at low price periods of the year.

For the purposes of the Hydrogen Blending Option with Pipeline Storage we have assumed that storage in pipelines is the most economic option, and have based the costs of storage (as set out in Table 4) on that assumption. Under the Hydrogen Blending Option with Pipeline Storage, our optimisation finds that it is least cost to invest in both hydrogen production and hydrogen storage, but that there is less investment in hydrogen storage (because of the higher capital cost) and more investment in hydrogen production (because less storage means more hydrogen production capacity is required to meet peak demand).

For the purposes of the Hydrogen Blending Option no Storage we have assumed that no form of hydrogen storage is economic, which means that hydrogen has to be produced each day to meet that days’ demand for hydrogen. This limits the extent to which hydrogen production can be scheduled to occur at times of low electricity prices.

Changes in electricity consumption due to electricity switching

Calculating the amount of electricity required to displace natural gas in the Electricity Switching Case is also somewhat complex. The reason is that the relative efficiency of natural gas appliances and electricity appliances is different, which means that the amount of energy input required to provide the equivalent energy output is different. This is most apparent for space heating, with reverse cycle air conditioning having a much higher coefficient of performance than gas space heaters.

To account for the different efficiency of reverse cycle air conditioning and gas space heaters we first need to estimate how much of the daily gas consumption to be displaced from AGN’s gas distribution network is used for space heating. Because we do not have data on daily gas use by appliance type, we have made the following simplifying assumptions:

- The average amount of gas used in the summer months (October through to March inclusive) is a reasonable representation of the amount of gas that will be used year round for purposes other than space heating (that is, for cooking, water heating or commercial use).
- The gas used in winter months (April to September) in excess of this average amount that is used is a reasonable representation of the amount of gas that will be used for space heating.

Having calculated the amount of the daily gas consumption displaced from the gas distribution network that is accounted for by space heating load, we can then account for the different efficiency of reverse cycle air conditioning and gas space heaters. We use an assumed coefficient of performance for space heating of 0.73, based on the mid-point of the efficiency of flued gas heaters reported by Alinta Energy, to calculate the amount of heat energy provided by this amount of gas used for space heating. We then use an assumed coefficient of performance for reverse cycle air conditioning of 2.5, based on a fact sheet published by Department of the Environment and Energy, to calculate the amount of electricity required to produce this same amount of heat energy. Adding this to the base load energy used for purposes other than space heating (which, for the purposes of simplicity, we assume is the same as the amount of energy used for those purposes for gas appliances) provides an estimate of the total electrical energy required to displace the daily gas consumption from the gas distribution network. This is depicted in Figure 16; it is apparent from Figure 16 that under this approach a lower amount of electrical energy is required in winter to displace a given amount of gas energy (due to the higher efficiency of reverse cycle air conditioning) but for the rest of the year the same amount of electrical energy is required to

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Indicative analysis of blending hydrogen in gas networks

Displace a given amount of gas energy. Based on this approach, Figure 17 shows annual electricity demand for the Base Case and the Electricity Switching Option. It is clear from Figure 17 that the additional electricity consumption resulting from switching 3.17% of gas demand on AGNs gas distribution network to electricity is only a very small proportion of Victoria’s total electricity consumption.

**Figure 16**: Electrical energy required to displace gas energy

![Figure 16: Electrical energy required to displace gas energy](image)

*Source: Frontier Economics*

**Figure 17**: Annual electricity demand in Victoria

![Figure 17: Annual electricity demand in Victoria](image)

*Source: Frontier Economics analysis of data from AEMO*
4.2 Changes in costs of producing and transporting natural gas

Changes in gas production costs

As discussed in Section 3, there is a decrease in gas production in both the Hydrogen Blending Options and the Electricity Switching Option. A decrease in gas production is likely to result in deferred investment in new gas production capacity and reduced costs of operating new and existing gas production facilities.

While a decrease in gas production is likely to result in a reduction in capital and operating costs, we note that the decrease in gas production is, by design, the same in the Hydrogen Blending Options and the Electricity Switching Option. This means that estimating the change in gas production costs will not drive differences in the total costs or benefits between the Hydrogen Blending Options and the Electricity Switching Option, since the difference in gas production costs will be the same.

Nevertheless, we calculate changes in the costs of gas production by multiplying the change in annual gas production each year by an estimate of the levelised cost of gas production.

The change in annual gas production is based on the estimated changes in gas consumption that we calculate for the Hydrogen Blending Options and the Electricity Switching Option, as discussed in Section 4.1.

The levelized cost of gas production that we use is based on estimates of the levelised cost of gas production developed as an input into AEMO’s Gas Statement of Opportunities (GSOO). Given that AEMO has identified that undeveloped gas fields will be required from the early 2020s in order to meet forecast gas demand as existing fields decline, we assume that marginal gas supply during the modelling period will come from undeveloped 2P or 2C reserves. We base the levelised cost of production on the average of AEMO’s estimates of levelised costs for all undeveloped 2P or 2C reserves in eastern Australia.

This levelised cost is $6.62/GJ, which we assume is expressed in $2019.

Changes in gas transmission costs

As discussed in Section 3, there is a decrease in gas transmission in both the Hydrogen Blending Options and the Electricity Switching Option. A decrease in gas transmission is likely to result in deferred pipeline investment and therefore a reduction in capital costs in the Hydrogen Blending Options and the Electricity Switching Option relative to the Base Case; because investment in pipeline capacity is likely to be required during the modelling period, a reduction in demand is likely to enable some part of this investment in new capacity to be deferred. Investment in pipeline capacity is likely to be required for two reasons:

• There is expected to be growth in total gas demand in most regions of eastern Australia, according to AEMO’s forecasts.

• Investment in pipeline capacity is likely to be necessary to bring new sources of gas to market as existing fields decline, according to AEMO’s forecasts.

While a decrease in gas transmission is likely to result in a reduction in capital costs, we note that the decrease in gas transmission is, by design, the same in the Hydrogen Blending Options and the Electricity Switching Option. This means that estimating the change in gas transmission costs will not drive differences in the total costs or benefits between the Hydrogen Blending Options and the Electricity Switching Option, since the difference in gas transmission costs will be the same.

Nevertheless, we calculate changes in the costs of gas transmission by multiplying the change in annual gas transmission each year by an estimate of the levelised cost of gas transmission.
The change in gas transmission is based on the estimated changes in gas consumption that we calculate for the Hydrogen Blending Options and the Electricity Switching Option, as discussed in Section 4.1.

As a proxy for the levelized cost of gas transmission we use estimates of the tariffs for gas transportation. In our experience, gas transportation tariffs are a reasonable proxy for levelized costs: gas transportation tariffs are generally in line with what is required to provide a return on and of capital investment over the expected life of the pipeline, plus operating costs. Given that we are assessing a change in gas transmission to Victoria, the proxy for levelised cost that we use is the gas transportation tariffs for the pipelines that would transport gas from Queensland’s coal seam methane gas fields to Victoria (that is, the South West Queensland Pipeline and the Moomba to Sydney Pipeline).

The multi-asset tariff offered by APA Group for transport from Wallumbilla to the Declared Wholesale Gas Market (DWGM) in Victoria is $2.00/GJ/day of MDQ,\(^\text{11}\) which we assume is expressed in $2019.

Changes in gas distribution costs

As discussed in Section 3, gas distribution costs may change in the Hydrogen Blending Options and the Electricity Switching Option for different reasons.

In the Hydrogen Blending Options there is an increase in the total volume of gas that needs to be delivered to provide a given amount of energy (due to the lower energy density of hydrogen) and there is also a change in the physical properties of the gas in the distribution network. While both of these changes have the potential to require modifications to the gas distribution network, and therefore result in additional costs, we are assuming that the gas distribution network is able to manage a hydrogen blend of 10% without modification or additional cost. This is consistent with a number of studies of hydrogen blending.\(^\text{12}\)

In the Electricity Switching Option there is a decrease in gas flows on the gas distribution network. It is not clear that this will result in any reduction in costs. The reason is that AGN’s gas distribution network, like a number of other gas distribution networks in Australia, is forecasting reductions in gas demand in the Base Case. With forecast reductions in gas demand there is likely little need for capital expenditure to increase the capacity of the gas distribution network; consequently, there is also little prospect that further reductions in gas demand will bring about reductions or deferrals of capital expenditure. This is particularly the case given that we have been asked to assume that the cases that we are examining are part of a longer term strategy of complete fuel substitution.

4.3 Changes in costs of generating and transporting electricity

Changes in generation costs

As discussed in Section 3, there is an increase in electricity generation (and potentially storage) in both the Hydrogen Blending Options and the Electricity Switching Option, although the magnitude and timing of the increase is different between the four options. An increase in electricity generation is likely to result in a requirement for additional investment in new generation capacity and increased costs of operating new and existing generators.

We estimate changes in the costs of generating (and storing) electricity by using our wholesale electricity market models – WHIRLYGIG and SYNC.


\(^{12}\) See, for example: CSIRO, National Hydrogen Roadmap: Pathways to an economically sustainable hydrogen industry in Australia, 2018.
WHIRLYGIG is a long-term investment model for electricity markets. WHIRLYGIG relies on a detailed representation of the electricity system and, based on this, optimises total generation cost in the electricity market, calculating the least cost mix of existing generation plant and new generation plant options to meet demand. Because WHIRLYGIG models both investment in, and operation of, utility-scale generation, WHIRLYGIG can be used to estimate the change in total generation costs that results from the change in electricity demand that occurs in the Hydrogen Blending Options and the Electricity Switching Option.

SYNC is an electricity market dispatch model that focuses on detailed short-term (half-hourly or less) fluctuations in demand, supply and system constraints. SYNC relies on a detailed representation of the electricity system and, based on this, determines market-clearing dispatch and pricing outcomes. SYNC makes use of investment outcomes modelled in WHIRLYGIG and uses a long-term forecast of bidding patterns. The model focuses on factors that affect short term price fluctuations and volatility in the wholesale market. These include half-hourly fluctuations in demand and intermittent wind and solar generation, ramping constraints and start-up costs of different technologies. SYNC provides a dispatch and wholesale price forecast at a half-hourly level.

Our Base Case modelling for WHIRLYGIG and SYNC uses a set of standard input assumptions, which are, for the most part, aligned with the input assumptions developed by the Australian Energy Market Operator (AEMO) for the Integrated System Plan (ISP). These standard input assumptions include constraints to ensure modelled outcomes are consistent with existing policies, such as the Large-scale Renewable Energy Target (LRET), the Victorian Renewable Energy Target (VRET) and the Queensland Renewable Energy Target (QRET). More detail on our modelling approach and modelling assumptions are provided in Appendix A.

Because we are interested in the costs and benefits of the Hydrogen Blending Options and the Electricity Switching Option from the point of view of the economy as a whole, we do not investigate the electricity procurement strategies that an operator of a hydrogen plant might adopt. It may be that an operator of a hydrogen plant is content to take the risk of purchasing from the spot market, or it may be that an operator of a hydrogen plant seeks to manage that risk through signing financial derivatives or a power purchase agreement (PPAs). The operator of a hydrogen plant may even decide to construct its own generation plant (although we consider it unlikely that it would decide not to connect that plant to the grid, given the potential benefits of trading through the NEM that are available). Whatever the case, the relevant change in costs and benefits are driven by changes in system-wide investment and dispatch decisions, which we think are best estimated using market modelling of the type described above.

Changes in transmission costs

As discussed in Section 3, there is an increase in electricity transmission in both the Hydrogen Blending Options and the Electricity Switching Option, although the magnitude and timing of the increase is different between the two options.

Under the Hydrogen Blending Option, the operator of the electrolyser is able to operate the plant in order to avoid times of high network tariffs and high wholesale electricity prices. In so doing, the operator of the electrolyser is able to avoid operating the plant at times of peak demand and, therefore, avoid contributing to an increase in peak demand on the transmission network. As a result, there should be no increase in transmission costs under the Hydrogen Blending Option.

Under the Hydrogen Blending Option with Pipeline Storage, the operator of the electrolyser is also able to operate the plant in order to avoid times of high network tariffs; although the amount of hydrogen storage is much lower in the Hydrogen Blending Option with Pipeline Storage, we consider that it is likely sufficient that there should be no increase in transmission costs.
Under the Hydrogen Blending Option no Storage, the operator of the electrolyser operates the plant in order to match the daily demand for hydrogen, but we assume that the operator is able to do so without operating the plant at times of highest network tariffs and wholesale prices during the day. In so doing, we assume the operator of the electrolyser is able to avoid contributing to an increase in peak demand and so avoid increased transmission costs (by operating overnight and during the morning on high electricity demand days, for instance). This is an option under the Hydrogen Blending Option no Storage, in part, because hydrogen can be stored during the day as linepack in the gas pipeline network, along with natural gas. This is an option even with existing infrastructure, and without additional investment in pipeline storage. While there is likely to be a limit to the extent to which the operator is able to operate over night and during the morning to avoid peak electricity demand while at the same time maintaining a reasonably consistent blend of hydrogen in the gas network, we expect that there would be sufficient flexibility to avoid the relatively short periods of peak electricity demand.

An increase in electricity transmission is likely to result in additional investment in transmission capacity and therefore an increase in capital costs in the Electricity Switching Option relative to the Base Case; because investment in transmission capacity is likely to be required during the modelling period, an increase in demand is likely to drive the need for additional capacity. We assume demand will relevantly increase for this option but not for the hydrogen options because we assume that additional electric appliances will not be turned off at peak times on the network in the same way that the hydrogen electrolyser can be turned off at peak times. Investment in transmission capacity is likely to be required for two reasons:

- There is expected to be growth in total electricity demand in most regions of eastern Australia, according to AEMO’s forecasts.
- Investment in transmission capacity is likely to be necessary to bring new sources of electricity to market as the generation mix in the NEM changes.

Given that AGN’s gas distribution network is in Victoria, we estimate changes in transmission costs for the Electricity Switching Option for AusNet Services’ electricity transmission network in Victoria.

We estimate changes in the costs for AusNet Services’ electricity transmission network based on an estimate of the change in flows on the transmission network and a benchmark cost for AusNet Services’ electricity transmission network. Since electricity network costs are principally driven by peak demand, the change in flow that is relevant is the change in peak demand, and the benchmark cost that is relevant is the cost per unit of peak demand.

For the Electricity Switching Option the change in peak demand for AusNet Services’ electricity transmission network is the same as the change in peak demand for AusNet Services’ electricity distribution network. The reason is that we are assuming that all affected customers are connected to the distribution network, and the increase in electricity consumption for these customers is supplied by transmission-connected generators. We discuss the change in peak demand for AusNet Services’ electricity distribution network in the section below.

Ideally, the benchmark cost that we would use for AusNet Services’ electricity transmission network would be an estimate of the long run marginal cost (LRMC) for the transmission network. However, since transmission network service providers are not required to publish an estimate of LRMC, we will use as a proxy the LRMC for sub transmission supply on AusNet Services’ electricity distribution network, as published by AusNet Services in its approved Tariff Structure Statement. This LRMC is $16.08/kVA, which we assume is expressed in $2017.

13 AusNet Electricity Services Pty Ltd, Addendum to Approved Tariff Structure Statement 2017-20, 7 September 2017.
This LRMC is calculated using an Average Incremental Cost (AIC) approach, which means that it is the net present value (NPV) of total capital and operating costs over the forecast period divided by the NPV of growth in peak demand over the forecast period.

Because the AIC accounts for both capital and operating costs, we are implicitly assuming that the increase in peak demand in the Electricity Switching Option requires augmentation of the transmission network. Given that we are assessing costs and benefits over the period to 2050, this seems appropriate. However, we note that if the increase in peak demand in the Electricity Switching Option can in fact be delivered using existing capacity on the transmission network our estimate of the change in transmission costs will be overstated.

Changes in distribution costs

As discussed in Section 3, there is an increase in electricity distribution only in the Electricity Switching Option, which sees greater electricity consumption by end customers. Given that most electricity distribution networks in Australia have spare capacity on many parts of their network, it is not obvious that an increase in electricity distribution in the Electricity Switching Option will lead to the need for investment in new capacity in the near term. However, since we are undertaking long-term modelling, we think it is appropriate to assume that an increase in electricity distribution will result in the need for investment in additional capacity.

Given the overlap between AGN’s gas distribution network and AusNet Services’ electricity distribution network, we estimate changes in distribution costs for the Electricity Switching Option by assuming that all changes in electricity consumption occur on AusNet Services’ electricity distribution network.

We estimate changes in the costs for AusNet Services’ electricity distribution network based on an estimate of the change in flows on the distribution network and a benchmark cost for AusNet Services’ electricity distribution network. Since electricity network costs are principally driven by peak demand, the change in flow that is relevant is the change in peak demand, and the benchmark cost that is relevant is the cost per unit of peak demand.

We estimate the change in peak demand for AusNet Services’ electricity distribution network by using the estimated changes in electricity consumption discussed that we calculate for the Electricity Switching Option in Section 4.1. The difference between peak demand in the Base Case and peak demand in the Electricity Switching Option provides a measure of the increase in peak demand on AusNet Services’ electricity distribution network.

The benchmark cost that we use for AusNet Services’ electricity distribution network is the estimate of the LRMC for low voltage supply on AusNet Services’ electricity distribution network, as published by AusNet Services in its approved Tariff Structure Statement.\(^{14}\)

This LRMC is $88.70/kVA, which we assume is expressed in $2017.

This LRMC is calculated using the same Average Incremental Cost (AIC) approach as is used to calculate the LRMC for sub transmission supply on AusNet Services’ electricity distribution network.

4.4 Changes in costs of producing and storing hydrogen

As discussed in Section 3, hydrogen production and storage is required in the Hydrogen Blending Option and the Hydrogen Blending Option with Pipeline Storage; hydrogen production (but no storage) is required in the Hydrogen Blending Option no Storage. As well as the increase in the cost of generating and transporting electricity that this requires (and which is accounted for in our estimates of electricity

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\(^{14}\) AusNet Electricity Services Pty Ltd, Addendum to Approved Tariff Structure Statement 2017-20, 7 September 2017.
generation and transmission costs) there are also capital and operating costs associated with this hydrogen production and storage.

The optimisation model of hydrogen production and storage that we have built (as discussed in Section 4.1) determines the amount of hydrogen production capacity and, if relevant, hydrogen storage capacity that is required in order to minimise the total cost of hydrogen production. We use the estimates of capital and operating costs of hydrogen production and storage that are set out in Table 2, Table 3 and Table 4 to determine the total capital and operating costs of this.

We assume that the operating costs set out in Table 2 include the costs of procuring water for use in the electrolyser. Electrolysers use a material amount of water – alkaline electrolysers are estimated to use 13 litres of water for each kilogram of hydrogen producer. This implies that the amount of water required to produce hydrogen to blend in AGN’s natural gas distribution network to a volume of 10% is 132,355 kLs per year. For context, this represents less than 0.1% of the annual capacity of the desalination plant at Wonthaggi. At an estimated cost of bulk water supply in Victoria of $2.50/kL this would imply a cost of bulk water of $330,887 per year. This is roughly 10% of our estimate of total operating costs for the electrolyser for the year, which indicates that it is not unreasonable to assume that the costs of procuring water for use in the electrolyser are already included in estimates of operating costs.

Likewise, we assume that the capital costs set out in Table 2 include land costs. Alkaline electrolysers are estimated to require 0.095 square meters per kW of capacity. Based on the modelled size of the electrolyser in the Hydrogen Blending Option, this implies a plant size of 7,375 square meters, or 1.82 acres. At a reported cost for industrial land in Melbourne of $238 per square meter, this equates to a land cost of $1.75 million, or $22.61/kW. This is roughly 2% of our estimate of capital costs for the electrolyser, which indicates that it is not unreasonable to assume that land costs are already included in estimates of capital costs.

**4.5 Summary of changes in costs**

Based on the discussion in Section 4.2 through Section 4.4, our approach to accounting for the changes in costs in the natural gas, electricity and hydrogen sectors is summarised in Table 5.
Table 5: Summary of treatment of costs

<table>
<thead>
<tr>
<th>SECTOR AND SUPPLY CHAIN</th>
<th>COST IMPACT INCLUDED, FOR OPTIONS IN WHICH RELEVANT CONSUMPTION CHANGES?</th>
<th>APPROACH TO ESTIMATING COST IMPACT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas production</td>
<td>Yes</td>
<td>Difference in cost based on AEMO estimate of levelized cost of gas production.</td>
</tr>
<tr>
<td>Gas transmission</td>
<td>Yes</td>
<td>Difference in cost based on transport tariff as proxy for levelized costs.</td>
</tr>
<tr>
<td>Gas distribution</td>
<td>No – since Base Case has falling demand on distribution network, further reductions in demand will not result in deferred investment.</td>
<td>-</td>
</tr>
<tr>
<td>Electricity generation</td>
<td>Yes</td>
<td>Difference in cost based on Frontier Economics' modelling of capital, fuel and operating costs.</td>
</tr>
<tr>
<td>Electricity transmission</td>
<td>Yes – in the Electricity Switching Option, because demand cannot be time-shifted. No – in the Hydrogen Blending Options, because we assume that the electrolyser will not operate at time of peak electricity network demand.</td>
<td>Difference in cost based on estimate of LRMC of network.</td>
</tr>
<tr>
<td>Electricity distribution</td>
<td>Yes</td>
<td>Difference in cost based on estimate of LRMC of network.</td>
</tr>
<tr>
<td>Hydrogen production</td>
<td>Yes</td>
<td>Difference in cost based on IEA estimates of capital and operating costs.</td>
</tr>
<tr>
<td>Hydrogen storage</td>
<td>Yes</td>
<td>Difference in cost based on DNV GL estimates of capital and operating costs.</td>
</tr>
</tbody>
</table>
5 RESULTS

This section presents the results of our modelling.

First, we present the results of our electricity sector modelling, highlighting the changes in investment in generation and storage plant, and the changes in operation of generation and storage plant, under the Hydrogen Blending Options and Electricity Switching Option, relative to the Base Case.

Second, we present the results of our cost benefit assessment. We present annual changes in costs under the Hydrogen Blending Options and Electricity Switching Option, relative to the Base Case, as well as a comparison of the 2025 Options and the 2030 Options.

5.1 Electricity sector modelling

Base Case Results

Figure 18 shows the year-on-year cumulative investment in new generation capacity in the NEM in the Base Case, by technology/fuel classification. We see significant investment in new renewables (primarily wind and solar PV) and open-cycle gas turbines (OCGT) and significant investment in pumped-storage hydro plant. Much of the investment occurs as existing coal-fired power stations retire.

Figure 18: Cumulative new generation investment – Base Case

Source: Frontier Economics’ modelling

Figure 19 shows the total installed generation capacity in the NEM in the Base Case (including both existing generation capacity in the NEM and the new investment seen in Figure 18). Figure 19 shows the shift in the generation mix in the NEM from one dominated by black coal and brown coal to one that is increasingly dominated by renewable generation, backed by storage.
Figure 19: Total installed capacity – Base Case

Figure 20 shows the total generation dispatch from plant in the NEM in the Base Case. As in Figure 19, it is clear that there is a substantial change over time in the mix of generation supplying electricity in the NEM. Dispatch from black coal and brown coal decreases significantly, while dispatch from wind and solar PV increases substantially.
Hydrogen Blending Option (2025)

Figure 21 shows the year-on-year cumulative investment differences in the NEM between the Base Case and the Hydrogen Blending Option (2025), by technology/fuel classification. Values above zero indicate that investment in a technology/fuel classification is greater in the scenario than in the Base Case for that particular year. Values below zero indicate that investment in a technology/fuel classification is lower in the scenario than in the Base Case for that particular year. Where there is a difference only for a period—such as the lower investment in wind generation in 2028/29 and 2029/30 seen in Figure 21—this reflects a difference in the timing of investment; in this case, investment in wind that occurs in 2028/29 and 2029/30 in the Base Case is deferred until 2030/31.

Figure 21 shows that overall investment is higher in the Hydrogen Blending Case (2025) than in the Base Case. This is due to the increase in electricity demand to meet hydrogen production requirements. This investment is made up primarily of renewable technologies—wind and utility-scale solar PV—reflecting the fact that this is the least cost mix of generation to build.

Figure 21 also shows an increase in investment in pumped-storage hydro capacity in the Hydrogen Blending Option (2025), almost exactly matched by a reduction in gas peaking plant. This reflects the fact that pumped hydro storage is able to take advantage of the increased investment in renewables, complementing them better than gas peaking plant. There is no material net increase in dispatchable capacity or storage capacity because the electrolyser operates at times of low prices (and low demand and/or high supply) which means that the electrolyser does not contribute to the need for additional capacity to meet peak demand or to manage solar and wind droughts.

In the Hydrogen Blending Option (2025), due to the increased demand compared to the Base Case, a unit of Yallourn W retires three years later than the Base Case, deferring some investment in wind and solar until 2030/31, when the retirement schedules realign.

Figure 21: Investment differences – Hydrogen Blending Option (2025)

![Bar chart showing investment differences](source: Frontier Economics' modelling)

Figure 22 illustrates the year-on-year output differences between the Base Case and the Hydrogen Blending Option (2025) by technology/fuel classification. Values above zero indicate that differences in output of a technology/fuel classification are greater in the scenario than in the Base Case for that particular year. Values below zero indicate that differences in output of a technology/fuel classification
are lower in the scenario than in the Base Case. The black line is the net difference in output between scenarios, which reflects the load added by hydrogen production and associated losses from transmission and storage in the NEM.

**Figure 22** reflects the increased output of the incremental renewable investment outlined in **Figure 21**. A combination of new renewable investment and increased dispatch from existing coal and, to a lesser extent, other fuels, are utilised to meet the incremental load added by hydrogen production. Years 2027/28 to 2029/30 show the effect of a unit of Yallourn W pushing back its retirement, increasing brown coal output compared to the Base Case, while decreasing black coal output and, to a lesser extent, other forms of generation. The reduction in dispatch of wind plant that occurs in 2028/29 and 2029/30 (displaced by additional generation from Yallourn) is a result of delayed investment in wind plant due to the delayed Yallourn W unit retirement, as seen in **Figure 21**.

**Figure 22**: Output differences – Hydrogen Blending Option (2025)

![Figure 22: Output differences – Hydrogen Blending Option (2025)](image)

*Source: Frontier Economics’ modelling*
Hydrogen Blending Option with Pipeline Storage (2025)

**Figure 23** shows the year-on-year cumulative investment differences in the NEM between the Base Case and the Hydrogen Blending Option with Pipeline Storage (2025), by technology/fuel classification. As with **Figure 21**, values above zero indicate that investment in a technology/fuel classification is greater in the scenario than in the Base Case for that particular year. Values below zero indicate that investment in a technology/fuel classification is lower in the scenario than in the Base Case for that particular year.

**Figure 23** shows that the investment differences for the Hydrogen Blending Option with Pipeline Storage (2025) are similar to the investment differences for the Hydrogen Blending Option (2025). The key change is that there is greater additional investment in storage (in the form of pumped hydro generation) in the Hydrogen Blending Option with Pipeline Storage (2025). In simple terms, the additional cost and therefore reduced investment in hydrogen storage in this case means that additional electricity storage is required. Without hydrogen storage, the electrolyser has to operate (and therefore use electricity) when customers use gas; providing electricity to the electrolyser at these times requires additional storage so that the additional electricity produced from renewable sources can be provided to the electrolyser at the times that it requires electricity.

In the Hydrogen Blending Option with Pipeline Storage (2025), due to the increased demand compared to the Base Case, a unit of Yallourn W retires three years later, deferring investment in gas mid-merit until 2030/31, when the retirement schedules realign.

**Figure 23**: Investment differences – Hydrogen Blending Option with Pipeline Storage (2025)

![Graph showing investment differences](source)

*Source: Frontier Economics’ modelling*

**Figure 24** reflects the increased output of the incremental renewable investment outlined in **Figure 23**. A combination of new renewable investment and increased generation from black coal in New South Wales and Queensland and, to a lesser extent, other fuels, are utilised to meet the incremental load added by the electrolyser. As in the Hydrogen Blending Option (2025), the timing of retirement of a Yallourn W unit means that in 2027/28 to 2029/30 brown coal output is increased as compared to the Base Case, replacing some output from black coal, deferring wind investment and resulting in some reduction in output from other forms of generation. After this, the increased demand is met by increased output from renewables and, to a lesser extent, black coal.
Figure 24: Output differences – Hydrogen Blending Option with Pipeline Storage (2025)

Source: Frontier Economics' modelling
Hydrogen Blending Option no Storage (2025)

Figure 25 shows the year-on-year cumulative investment differences in the NEM between the Base Case and the Hydrogen Blending Option no Storage (2025), by technology/fuel classification. As with Figure 21, values above zero indicate that investment in a technology/fuel classification is greater in the scenario than in the Base Case for that particular year. Values below zero indicate that investment in a technology/fuel classification is lower in the scenario than in the Base Case for that particular year.

Figure 25 shows that the investment differences for the Hydrogen Blending Option no Storage (2025) and very similar to the investment differences for the Hydrogen Blending Option (2025). The key change is that there is greater additional investment in storage in the Hydrogen Blending Option no Storage (2025); in simple terms, the unavailability of hydrogen storage in this case means that additional electricity storage is required. This replaces the need to build peaking gas plant, as the storage is able to firm up renewable generation.

In the Hydrogen Blending Option no Storage (2025), due to the increased demand compared to the Base Case, a unit of Yallourn W delays retiring by one year in 2024/25 and a second unit of Yallourn W from 2027/28 till 2030/31, where afterwards the investment in renewables and pumped hydro increases to meet the increased demand.

Figure 25: Investment differences – Hydrogen Blending Option no Storage (2025)

Figure 26 reflects the increased output of the incremental renewable investment outlined in Figure 25. A combination of new renewable investment and increased generation from black coal in New South Wales and Queensland and, to a lesser extent, other fuels, are utilised to meet the incremental load added by electrification. As in the Hydrogen Blending Option (2025), the timing of retirement of Yallourn W units means that in 2024/25 and from 2027/28 to 2030/31 brown coal output is increased as compared to the Base Case, replacing some output from black coal, deferring some wind investment and resulting in some reduction in output from other forms of generation. After this, the increased demand is met by increased output from renewables and, to a lesser extent, black coal.
Figure 26: Output differences – Hydrogen Blending Option no Storage, 2025

Source: Frontier Economics’ modelling
Electricity Switching Option (2025)

Figure 27 shows the year-on-year cumulative investment differences in the NEM between the Base Case and the Electricity Switching Option (2025), by technology/fuel classification. As with Figure 21, values above zero indicate that investment in a technology/fuel classification is greater in the scenario than in the Base for that particular year. Values below zero indicate that investment in a technology/fuel classification is lower in the scenario than in the Base Case for that particular year.

Figure 27 shows that overall investment is higher in the Electricity Switching Option (2025) than in the Base Case, due primarily to increased demand for electricity due to switching. This investment is made up of renewable technologies – utility-scale solar PV and wind – to meet increased annual consumption, and additional gas peaking plant, and a small of pumped hydro, to meet the peak demand increase from the increase in electrical appliances. This occurs to manage the intermittency of the additional renewable generation and to meet the increase in peak demand resulting from greater use of electrical appliances. Unlike in the Hydrogen Blending Option (2025) there is a material net increase in dispatchable capacity to meet peak demand.

Compared with the outcomes in the Hydrogen Blending Option (2025) there is less additional investment in renewable generation technologies – solar PV and wind – because the increase in annual consumption is lower. However, there is also material additional investment in gas peaking plant to meet higher peak demand.

In the Electricity Switching Option (2025), due to the increased demand compared to the Base Case, a unit of Yallourn W retires four years later in 2030/31, deferring investment in renewables and gas peaking plant until 2031/32, when the retirement schedules realign.

Figure 27: Investment differences – Electricity Switching Option, 2025

Figure 28 reflects the increased output of the incremental investment outlined in Figure 27. A combination of new renewable investment and increased generation from black coal in New South Wales and Queensland and, to a lesser extent, other fuels, are utilised to meet the incremental load added by electrification. As in the Hydrogen Blending Option (2025), the timing of retirement of a Yallourn W unit means that in 2028 to 2030 brown coal output is increased as compared to the Base...
Case, replacing some output from black coal and deferring wind investment. After this, the increased demand is met by increased output from renewables and black coal.

The main differences between the Electricity Switching Option (2025) and the Hydrogen Blending Option (2025) stem from the differences in Yallourn unit retirements and the differences in the increase in annual consumption of electricity. In the Electricity Switching Option (2025), a Yallourn unit retires one year later which is evident in the increased brown coal output in 2031. After this happens, the retirement schedules match and the only material output differences are driven by the increased annual consumption. The Electricity Switching Option (2025) has a lower increase in annual consumption than the Hydrogen Blending Option (2025) which is evident in the lower renewables output from 2032 onwards.

**Figure 28: Output differences – Electricity Switching Option (2025)**

![Graph showing output differences](image)

*Source: Frontier Economics’ modelling*
Hydrogen Blending Option (2030)

Figure 29 shows the year-on-year cumulative investment differences in the NEM between the Base Case and the Hydrogen Blending Option (2030), by technology/fuel classification. Values above zero indicate that investment in a technology/fuel classification is greater in the scenario than in the Base Case for that particular year. Values below zero indicate that investment in a technology/fuel classification is lower in the scenario than in the Base Case for that particular year.

Figure 29 shows that overall investment is higher in the Hydrogen Blending Case (2030) than in the Base Case. This is due to the increase in electricity demand to meet hydrogen production requirements. This investment is made up primarily of renewable technologies – wind and utility-scale solar PV – reflecting the fact that this is the least cost mix of generation to build.

Figure 29 also shows an increase in investment in pumped-storage hydro capacity in the Hydrogen Blending Option (2030), almost exactly matched by a reduction in gas peaking plant. This reflects the fact that pumped hydro storage is able to take advantage of the increased investment in renewables, complementing them better than gas peaking plant. There is no material net increase in dispatchable capacity or storage capacity because the electrolyser operates at times of low prices (and low demand and/or high supply) which means that the electrolyser does not contribute to the need for additional capacity to meet peak demand or to manage solar and wind droughts.

**Figure 29: Investment differences – Hydrogen Blending Option (2030)**

![Figure 29: Investment differences – Hydrogen Blending Option (2030)](image)

Source: Frontier Economics' modelling

Figure 30 illustrates the year-on-year output differences between the Base Case and the Hydrogen Blending Option (2030) by technology/fuel classification. Values above zero indicate that differences in output of a technology/fuel classification are greater in the scenario than in the Base Case for that particular year. Values below zero indicate that differences in output of a technology/fuel classification are lower in the scenario than in the Base Case. The black line is the net difference in output between scenarios, which reflects the load added by hydrogen production and associated losses from transmission and storage in the NEM.

Figure 30 reflects the increased output of the incremental renewable investment outlined in Figure 29. A combination of new renewable investment and increased dispatch from existing coal and, to a lesser extent, other fuels, are utilised to meet the incremental load added by hydrogen production. The timing...
and level of renewable entry in the Hydrogen Blending Option (2030) means that in some years, coal generation is lower than the Base Case, and in other years, it is higher than the Base Case to meet the incremental hydrogen load not being met by the additional renewables.

**Figure 30**: Output differences – Hydrogen Blending Option (2030)
Hydrogen Blending Option with Pipeline Storage (2030)

Figure 31 shows the year-on-year cumulative investment differences in the NEM between the Base Case and the Hydrogen Blending Option with Pipeline Storage (2030), by technology/fuel classification. As with Figure 29, values above zero indicate that investment in a technology/fuel classification is greater in the scenario than in the Base Case for that particular year. Values below zero indicate that investment in a technology/fuel classification is lower in the scenario than in the Base Case for that particular year.

Figure 31 shows that the investment differences for the Hydrogen Blending Option with Pipeline Storage (2030) are very similar to the investment differences for the Hydrogen Blending Option (2030). The key change is that there is greater additional investment in storage (in the form of pumped hydro generation) in the Hydrogen Blending Option with Pipeline Storage (2030); in simple terms, the additional cost and therefore reduced investment in hydrogen storage in this case means that additional electricity storage is required. This replaces the need to build peaking gas plant, as the storage is able to firm up renewable generation.

Figure 31: Investment differences – Hydrogen Blending Option with Pipeline Storage (2030)

Figure 32 reflects the increased output of the incremental renewable investment outlined in Figure 31. A combination of new renewable investment and increased dispatch from existing coal and, to a lesser extent, other fuels, are utilised to meet the incremental load added by the hydrogen production. The timing and level of renewable entry in the Hydrogen Blending Option with Pipeline Storage (2030) means that in some years, coal generation is lower than the Base Case, and in other years, it is higher than the Base Case to meet the incremental hydrogen load not being met by the additional renewables.
**Figure 32**: Output differences – Hydrogen Blending Option with Pipeline Storage (2030)

Source: Frontier Economics’ modelling
Hydrogen Blending Option no Storage (2030)

Figure 33 shows the year-on-year cumulative investment differences in the NEM between the Base Case and the Hydrogen Blending Option no Storage (2030), by technology/fuel classification. As with Figure 29, values above zero indicate that investment in a technology/fuel classification is greater in the scenario than in the Base Case for that particular year. Values below zero indicate that investment in a technology/fuel classification is lower in the scenario than in the Base Case for that particular year.

Figure 33 shows that the investment differences for the Hydrogen Blending Option no Storage (2030) are very similar to the investment differences for the Hydrogen Blending Option (2030). The key change is that there is greater additional investment in storage in the Hydrogen Blending Option no Storage (2030); in simple terms, the unavailability of hydrogen storage in this case means that additional electricity storage is required. This replaces the need to build peaking gas plant, as the storage is able to firm up renewable generation.

Figure 33: Investment differences – Hydrogen Blending Option no Storage (2030)

![Figure 33: Investment differences – Hydrogen Blending Option no Storage (2030)](image)

Source: Frontier Economics’ modelling

Figure 34 reflects the increased output of the incremental renewable investment outlined in Figure 33. A combination of new renewable investment and increased dispatch from existing coal and, to a lesser extent, other fuels, are utilised to meet the incremental load added by the hydrogen production. The timing and level of renewable entry in the Hydrogen Blending Option no Storage (2030) means that in some years, coal generation is lower than the Base Case, and in other years, it is higher than the Base Case to meet the incremental hydrogen load not being met by the additional renewables.
Figure 34: Output differences – Hydrogen Blending Option no Storage (2030)

Source: Frontier Economics' modelling
Electricity Switching Option (2030)

Figure 35 shows the year-on-year cumulative investment differences in the NEM between the Base Case and the Electricity Switching Option (2030), by technology/fuel classification. As with Figure 29, values above zero indicate that investment in a technology/fuel classification is greater in the scenario than in the Base Case for that particular year. Values below zero indicate that investment in a technology/fuel classification is lower in the scenario than in the Base Case for that particular year.

Figure 35 shows that overall investment is higher in the Electricity Switching Option (2030) than in the Base Case, due primarily to increased demand for electricity due to switching. This investment is made up of renewable technologies; predominantly utility-scale solar PV and wind. Gas peaking plant, and a small amount of additional pumped hydro, is also built to meet the peak demand increase from the increase in electrical appliances.

Compared with the outcomes in the Hydrogen Blending Option (2030) there is less additional investment in renewable generation technologies – solar PV and wind – because the increase in annual consumption is lower. However, there is also material additional investment in gas peaking plant to meet higher peak demand.

Figure 35: Investment differences – Electricity Switching Option, 2030

Figure 36 reflects the increased output of the incremental renewable investment outlined in Figure 35. A combination of new renewable investment, new investment in gas peaking plant, and increased dispatch from existing coal and, to a lesser extent, other fuels, are utilised to meet the incremental load added by the hydrogen production.

The main differences between the Electricity Switching Option (2030) and the Hydrogen Blending Option (2030) stem from the differences in increase in electricity demand. The Electricity Switching Option (2030) has a lower increase in demand than the Hydrogen Blending Option (2030) which is evident in the lower renewables output from 2030 onwards.
Figure 36: Output differences – Electricity Switching Option, 2030

Source: Frontier Economics' modelling
5.2 Cost benefit assessment

Hydrogen Blending Option (2025)

Figure 37 shows the annual cost difference between the Hydrogen Blending Option (2025) and the Base Case. Values above zero indicate that costs are higher for the Hydrogen Blending Option (2025) than the Base Case; values below zero indicate that costs are lower for the Hydrogen Blending Option (2025) than the Base Case. Two versions of these results are shown: the top set of results show costs aggregated by sector, the bottom set of results show a more detailed breakdown of costs. These annual cost differences reflect the amortisation of any additional capital costs in the hydrogen, electricity or gas sectors over the life of the assets.

From 2025, hydrogen blending commences. Therefore, annual hydrogen sector costs (the costs of producing and storing hydrogen) start at $9.5 million in 2025 and rise to $10 million in 2050, with ~94% of the hydrogen sector costs being associated with hydrogen production and the rest being associated with hydrogen storage. This reflects the relatively higher cost of hydrogen production relative to hydrogen storage.

Annual electricity production costs increase in 2025 as compared to the Base Case, and for all years thereafter, as additional electricity is produced to operate the hydrogen electrolyser. The additional costs vary by year, but are generally in the range of $15 million to $30 million. Electricity production costs are lower in one year – in 2029/30 – than the other years because this is the year in which the most new generation investment in the Hydrogen Blending Option (2025) is deferred as a result of the one unit of Yallourn power station retiring several years later. While this delayed retirement results in higher fixed operating costs, fuel costs and investment costs are lower.

Electricity network costs do not increase as it is cost minimising to invest in hydrogen storage and have the electrolyser only operate during off-peak periods.

Annual gas sector costs fall by $12 million in 2025 as compared to the Base Case as some natural gas consumption on the AGN Distribution Network is displaced by hydrogen. This cost reduction increases to $13 million by 2050.
Figure 37: Annual Cost Comparison – Hydrogen Blending Option (2025) against the Base Case

Source: Frontier Economics
Hydrogen Blending Option with Pipeline Storage (2025)

Figure 38 shows the annual cost difference between the Hydrogen Blending Option with Pipeline Storage (2025) and the Base Case. Values above zero indicate that costs are higher for the Hydrogen Blending Option with Pipeline Storage (2025) than the Base Case; values below zero indicate that costs are lower for the Hydrogen Blending Option with Pipeline Storage (2025) than the Base Case. Two versions of these results are shown: the top set of results show costs aggregated by sector, the bottom set of results show a more detailed breakdown of costs. These annual cost differences reflect the amortisation of any additional capital costs in the hydrogen, electricity or gas sectors over the life of the assets.

From 2025, hydrogen blending commences. Therefore, annual hydrogen sector costs (the costs of producing and storing hydrogen) start at $10 million in 2025 and rise to $11 million in 2050, with ~92% of the hydrogen sector costs being associated with hydrogen production and the rest being associated with hydrogen storage.

Annual electricity production costs increase in 2025 as compared to the Base Case, and for all years thereafter, as additional electricity is produced to operate the hydrogen electrolyser. The additional costs vary by year, but are generally in the range of $15 million to $50 million. The difference in electricity production costs are higher in all years, although in 2030 this difference is small due to the extra Yallourn unit staying operating longer in the Hydrogen Blending Option with Pipeline Storage (2025) than the Base Case (reflecting higher electricity demand for hydrogen production). While this delayed retirement results in higher fixed operating costs, fuel costs and investment costs are lower.

Electricity network costs do not increase as it is cost minimising to invest in hydrogen storage and have the electrolyser only operate during off-peak periods.

Annual gas sector costs fall by $12 million in 2025 as compared to the Base Case as some natural gas consumption on the AGN Distribution Network is displaced by hydrogen. This cost reduction increases to $13 million by 2050.
Figure 38: Annual Cost Comparison – Hydrogen Blending Option with Pipeline Storage (2025) against the Base Case

Source: Frontier Economics
Hydrogen Blending Option no Storage (2025)

Figure 39 shows the annual cost difference between the Hydrogen Blending Option no Storage (2025) and the Base Case. Values above zero indicate that costs are higher for the Hydrogen Blending Option no Storage (2025) than the Base Case; values below zero indicate that costs are lower for the Hydrogen Blending Option no Storage (2025) than the Base Case. Two versions of these results are shown: the top set of results show costs aggregated by sector, the bottom set of results show a more detailed breakdown of costs. These annual cost differences reflect the amortisation of any additional capital costs in the hydrogen, electricity or gas sectors over the life of the assets.

Comparing Figure 37 and Figure 39 it is clear that the costs are materially higher where hydrogen storage is not an option:

- Additional hydrogen production capacity is required in order to meet demand for hydrogen on peak days without any storage, resulting in higher hydrogen production costs.
- With little opportunity to schedule hydrogen production for periods of low electricity costs, the costs of electricity required for hydrogen production are materially higher.

These additional costs due to the need to produce hydrogen each day to meet daily demand more than outweigh the savings from not having to build and operate a hydrogen storage facility. As discussed in the context of the Hydrogen Blending Option (2025), the direct costs of hydrogen storage are relatively small relative to hydrogen production (representing only 6% of hydrogen sector costs in the Hydrogen Blending Option (2025)), which means that the savings from avoiding these direct costs are also relatively small. Indeed, the savings from not having to build and operate a hydrogen storage facility (which are around $0.5 million per annum) are smaller than even the additional costs of hydrogen production capacity required to meet peak daily demand (which are around $2 million per annum).

In short, if hydrogen storage is not a feasible and economic option, the cost of blending hydrogen in the natural gas network increases materially.
**Figure 39:** Annual Cost Comparison – Hydrogen Blending Option no Storage (2025) against the Base Case

*Source: Frontier Economics*
Electricity Switching Option (2025)

Figure 40 shows the annual cost difference between the Electricity Switching Option (2025) and the Base Case. Values above zero indicate that costs are higher for the Electricity Switching Option (2025) than the Base Case; values below zero indicate that costs are lower for the Electricity Switching Option (2025) than the Base Case. Two versions of these results are shown: the top set of results show costs aggregated by sector, the bottom set of results show a more detailed breakdown of costs. These annual cost differences reflect the amortisation of any additional capital costs in the hydrogen, electricity or gas sectors over the life of the assets.

From 2025, electricity switching commences. Annual electricity production and network costs increase in 2025 as compared to the Base Case, as additional electricity is produced and transported to customers, to displace natural gas consumption.

The annual increase in electricity production costs vary year on year. Electricity production costs are generally higher, as a result of the additional costs of meeting higher electricity demand. Generally, the increase in electricity production costs is between $13 million and $40 million. Electricity production costs are almost equal to the Base Case in a few years as a result of the one unit of Yallourn power station retiring several years later in the Electricity Switching Option (2025) than the Base Case (reflecting higher electricity demand for hydrogen production). While this delayed retirement results in higher fixed operating costs, fuel costs and investment costs are lower.

Annual electricity transport costs increase by $7.5 million in 2025 as compared to the Base Case as additional electricity is transported. This cost is $8 million by 2050.

Annual gas sector costs fall by $12 million in 2025 as compared to the Base Case as some natural gas consumption on the AGN Distribution Network is displaced by electricity. This cost reduction increases to $13 million by 2050. This decrease in costs is the same as in the Hydrogen Blending Case because there is an equivalent reduction in gas production and transport.
Figure 40: Annual Cost Comparison – Electricity Switching Option (2025) against the Base Case

Source: Frontier Economics
Hydrogen Blending Option (2030)

Figure 41 shows the annual cost difference between the Hydrogen Blending Option (2030) and the Base Case. Values above zero indicate that costs are higher for the Hydrogen Blending Option (2030) than the Base Case; values below zero indicate that costs are lower for the Hydrogen Blending Option (2030) than the Base Case. Two versions of these results are shown: the top set of results show costs aggregated by sector, the bottom set of results show a more detailed breakdown of costs. These annual cost differences reflect the amortisation of any additional capital costs in the hydrogen, electricity or gas sectors over the life of the assets.

From 2030, hydrogen blending commences. Therefore, annual hydrogen sector costs (the costs of producing and storing hydrogen) start at $8.5 million in 2030 and rise to $9 million in 2050, with ~91% of the hydrogen sector costs being associated with hydrogen production and the rest being associated with hydrogen storage. This reflects the relatively higher cost of hydrogen production relative to hydrogen storage.

Annual electricity production costs increase in 2030 as compared to the Base Case, and for all years thereafter, as additional electricity is produced to operate the hydrogen electrolyser. The additional costs vary by year, but are generally in the range of $15 million to $30 million.

Electricity network costs do not increase as it is cost minimising to invest in hydrogen storage and have the electrolyser only operate during off-peak periods.

Annual gas sector costs fall by $12 million in 2030 as compared to the Base Case as some natural gas consumption on the AGN Distribution Network is displaced by hydrogen. This cost reduction increases to $13 million by 2050.
Figure 41: Annual Cost Comparison – Hydrogen Blending Option (2030) against the Base Case

Source: Frontier Economics
Hydrogen Blending Option with Pipeline Storage (2030)

Figure 42 shows the annual cost difference between the Hydrogen Blending Option with Pipeline Storage (2030) and the Base Case. Values above zero indicate that costs are higher for the Hydrogen Blending Option with Pipeline Storage (2030) than the Base Case; values below zero indicate that costs are lower for the Hydrogen Blending Option with Pipeline Storage (2030) than the Base Case. Two versions of these results are shown: the top set of results show costs aggregated by sector, the bottom set of results show a more detailed breakdown of costs. These annual cost differences reflect the amortisation of any additional capital costs in the hydrogen, electricity or gas sectors over the life of the assets.

From 2030, hydrogen blending commences. Therefore, annual hydrogen sector costs (the costs of producing and storing hydrogen) start at $8 million in 2030 and stay stable until 2050, with ~91% of the hydrogen sector costs being associated with hydrogen production and the rest being associated with hydrogen storage.

Annual electricity production costs increase in 2030 as compared to the Base Case, and for almost all years thereafter, as additional electricity is produced to operate the hydrogen electrolyser. The additional costs vary by year, but are generally in the range of $2 million to $45 million.

Electricity network costs do not increase as it is cost minimising to invest in hydrogen storage and have the electrolyser only operate during off-peak periods.

Annual gas sector costs fall by $12 million in 2030 as compared to the Base Case as some natural gas consumption on the AGN Distribution Network is displaced by hydrogen. This cost reduction increases to $13 million by 2050.
Figure 42: Annual Cost Comparison – Hydrogen Blending Option with Pipeline Storage (2030) against the Base Case

Source: Frontier Economics
Hydrogen Blending Option no Storage (2030)

Figure 43 shows the annual cost difference between the Hydrogen Blending Option no Storage (2030) and the Base Case. Values above zero indicate that costs are higher for the Hydrogen Blending Option no Storage (2030) than the Base Case; values below zero indicate that costs are lower for the Hydrogen Blending Option no Storage (2030) than the Base Case. Two versions of these results are shown: the top set of results show costs aggregated by sector, the bottom set of results show a more detailed breakdown of costs. These annual cost differences reflect the amortisation of any additional capital costs in the hydrogen, electricity or gas sectors over the life of the assets.

Comparing Figure 41 and Figure 43 it is clear that the costs are materially higher where hydrogen storage is not an option:

- Additional hydrogen production capacity is required in order to meet demand for hydrogen on peak days without any storage, resulting in higher hydrogen production costs.
- With little opportunity to schedule hydrogen production for periods of low electricity costs, the costs of electricity required for hydrogen production are materially higher.

These additional costs due to the need to produce hydrogen each day to meet daily demand more than outweigh the savings from not having to build and operate a hydrogen storage facility. As discussed in the context of the Hydrogen Blending Option (2030), the direct costs of hydrogen storage are relatively small relative to hydrogen production (representing only 9% of hydrogen sector costs), which means that the savings from avoiding this direct cost are also relatively small. Indeed, the savings from not having to build and operate a hydrogen storage facility (which are around $0.7 million per annum) are mostly the same as the additional costs of hydrogen production capacity required to meet peak daily demand (which are also around $0.7 million per annum). Most of the savings from hydrogen storage come from being able to produce hydrogen at periods of low electricity prices, because hydrogen storage enables the shifting of supply to higher demand periods.

In short, if hydrogen storage is not a feasible and economic option, the cost of blending hydrogen in the natural gas network increases materially.
Figure 43: Annual Cost Comparison – Hydrogen Blending Option no Storage (2030) against the Base Case

Source: Frontier Economics
Electricity Switching Option (2030)

**Figure 44** shows the annual cost difference between the Electricity Switching Option (2030) and the Base Case. Values above zero indicate that costs are higher for the Electricity Switching Option (2030) than the Base Case; values below zero indicate that costs are lower for the Electricity Switching Option (2030) than the Base Case. Two versions of these results are shown: the top set of results show costs aggregated by sector, the bottom set of results show a more detailed breakdown of costs. These annual cost differences reflect the amortisation of any additional capital costs in the hydrogen, electricity or gas sectors over the life of the assets.

From 2020 to 2030, there are slight differences in electricity production costs as investment in the electricity system responds to the expectation of higher demand from 2030. From 2030, electricity switching commences. Annual electricity production and network costs increase in 2030 as compared to the Base Case as additional electricity is produced and transported to customers, to displace natural gas consumption.

The annual increase in electricity production costs vary year on year. Electricity production costs are generally higher, as a result of the additional costs of meeting higher electricity demand. Generally, the increase in electricity production costs is between $15 million and $40 million.

Annual electricity transport costs increase by $7.5 million in 2030 as compared to the Base Case as additional electricity is transported. This cost is $8 million by 2050.

Annual gas sector costs fall by $12 million in 2030 as compared to the Base Case as some natural gas consumption on the AGN Distribution Network is displaced by electricity. This cost reduction increases to $13 million by 2050. This decrease in costs is the same as in the Hydrogen Blending Case because there is an equivalent reduction in gas production and transport.
Figure 44: Annual Cost Comparison – Electricity Switching Option (2030) against the Base Case

Source: Frontier Economics
Summary and comparison

Figure 45 shows the annual cost difference between the Hydrogen Blending Option (2025) and the Electricity Switching Option (2025). Values above zero indicate that costs are higher for the Hydrogen Blending Option (2025) than the Electricity Switching Option (2025); values below zero indicate that costs are lower for the Hydrogen Blending Option (2025) than the Electricity Switching Option (2025). Two versions of these results are shown: the top set of results show costs aggregated by sector, the bottom set of results show a more detailed breakdown of costs.

From 2025, natural gas is substituted by hydrogen and electricity for the 2 cases respectively.

Electricity production costs for the Electricity Switching Option (2025) are lower than in the Hydrogen Blending Option (2025) until 2030/31; thereafter electricity production costs are higher for the Electricity Switching Option (2025). The main factor at play is the fact that the increased peak demand in the Electricity Switching Option can be met by extending the life of a Yallourn unit, thus using sunk capital to meet increased demand. However, after Yallourn retires, the Electricity Switching Option (2025) must invest in extra capacity to meet the increase in peak demand. Delaying this capital investment until 2031/32 however, is what drives the lower NPV for the Electricity Switching Option compared to the Hydrogen Blending Option.

Electricity network costs for the Hydrogen Blending Option are lower than in the Electricity Switching Option because the operation of the hydrogen electrolyser means that there is no need for increased capacity on the electricity network.
Figure 45: Annual Cost Comparison – Hydrogen Blending Option (2025) against Electricity Switching Option (2025)
Figure 46 shows the annual cost difference between the Hydrogen Blending Option (2030) and the Electricity Switching Option (2030). Values above zero indicate that costs are higher for the Hydrogen Blending Option (2030) than the Electricity Switching Option (2030); values below zero indicate that costs are lower for the Hydrogen Blending Option (2030) than the Electricity Switching Option (2030). Two versions of these results are shown: the top set of results show costs aggregated by sector, the bottom set of results show a more detailed breakdown of costs.

From 2030, natural gas is substituted by hydrogen and electricity for the 2 cases respectively.

Electricity production costs for the Hydrogen Blending Option (2030) are lower than in the Electricity Switching Option (2030), except in year 2030. The main factors at play is the fact that hydrogen can be easily stored means that the hydrogen electrolyser can be operated at times that result in lower additional electricity generation costs than in the Electricity Switching Option (2030).

Electricity network costs for the Hydrogen Blending Option are lower than in the Electricity Switching Option because the operation of the hydrogen electrolyser means that there is no need for increased capacity on the electricity network.
**Figure 46**: Annual Cost Comparison – Hydrogen Blending Option (2030) against Electricity Switching Option (2030)
5.3 Indicative costs and benefits of steam methane reforming

As discussed in Section 2.3, for the purposes of this study, in the scenarios that we have modelled, we assume that hydrogen will be produced using electrolysis rather than being produced thermochemically. We noted earlier that where hydrogen is produced from natural gas, there are three key factors that influence the cost of production:

- Natural gas prices in eastern Australia have recently been above long-term averages, although they have fallen in recent months. Most forecasts of future gas prices – including from AEMO – are for gas prices to remain above long-term averages.
- Natural gas supply to the domestic market in eastern Australia remains tight.
- The capital cost of steam methane reforming are forecasts to be higher than the capital costs of electrolysis, particularly in the steam methane reforming incorporate carbon capture and storage (CCS).

Without CCS, producing hydrogen thermochemically results in significant carbon emissions. While most hydrogen is produced using steam reforming of natural gas, there are indications that the use of natural gas is more expensive than other methods of production (such as electrolysis). The capital and operating costs of steam methane reforming are around 25% higher (or 65% higher with CCS) than electrolysis in 2030 and close to two times (or two-and-a-half times for CCS) the capital costs of electrolysis in 2050 (as the capital costs of electrolysis continue to fall in the long term).

While we have not modelled thermochemical hydrogen production, we have undertaken some analysis to assess the relative costs compared to hydrogen production using electrolysis. Specifically, we have compared the costs of hydrogen production using electrolysis (used in the Hydrogen Blending Options) with the costs of hydrogen production using steam methane reforming (steam methane reforming). Our analysis revealed the following:

- The forecast cost of gas supply and transmission to supply the steam methane reformer is lower than the forecast of cost of electricity supply and transmission to supply the electrolyser.
- There remain carbon emissions even with steam methane reforming with CCS (the IEA estimates 1 kgCO₂/kgH₂), while electrolysis supplied with 100% renewable electricity has no associated carbon emissions. While there is currently no direct cost of carbon emissions in Australia, these carbon emissions may be considered a long-term risk for investors due to the potential for policy change in relation to carbon emissions.

How these various factors interact, and which technology will ultimately be cheaper, will depend on circumstances in electricity and gas markets. Where additional electricity is available at low cost – as we forecast that it will be during the 2020s – this makes it more likely that electrolysis will be the lower cost option for producing hydrogen. Where gas prices are lower – for instance, if global LNG prices and, therefore, LNG net-back prices remain low in the long term – this makes it more likely that steam methane reforming will be the lower cost option for producing hydrogen.

Note that this analysis is based on a comparison of electrolysis with steam methane reforming based on the assumption that the feedstock for the steam methane reformer will be natural gas delivered through the gas transmission network in eastern Australia (with the gas production and gas transmission costs associated with that).

An alternative to steam methane reforming with natural gas is to produce hydrogen through coal gasification. The Hydrogen Energy Supply Chain (HESC) in Victoria is developing a pilot project to demonstrate a fully integrated supply chain between Australia and Japan in which hydrogen is produced using existing coal gasification technologies from Victorian brown in the Latrobe Valley. While estimates from the IEA suggest that coal gasification with CCS has a higher capital cost than steam methane reforming, the relative cost difference between the technologies will depend on the cost of coal and the cost of CO₂ capture and storage. It is also possible that electrolysis will become more competitive as the cost of electrolysis continues to fall.
reforming with CCS, the lower cost of brown coal may nevertheless mean that coal gasification with CCS is economic.
6 CONCLUSIONS

As discussed in Section 5, we have quantified the direct costs of the Base Case and each of the options that we have analysed in each of the electricity sector, the gas sector and the hydrogen sector. Table 6 reports the net present value (NPV) of the difference in these direct costs for the options compared with the Base Case. These NPVs are calculated over the full modelling period to 2050.

There are a number of key conclusions that can be drawn from Table 6:

- The NPV of the direct costs of each of the options is higher than the NPV of the direct costs in the Base Case; in other words, direct costs increase under each of these options relative to the Base Case. However, it is important to bear in mind that there are a number of costs and benefits that are not accounted for in this comparison, as discussed further below.

- For the 2025 options, the NPV of the direct costs of the Hydrogen Blending Option is higher than the NPV of the direct costs of the Electricity Switching Option. For the 2030 options, this is reversed, with the NPV of the direct costs of the Hydrogen Blending Option lower than the NPV of the direct costs of the Electricity Switching Option. In the 2025 options, retirement of one or more units of Yallourn can be deferred if there is higher demand, meaning that the higher demand can make use of committed capital. This is of particular benefit for the Electricity Switching Option, for which the increase in both peak electricity demand and annual electricity consumption is higher than in the Hydrogen Blending Option. In the 2030 options, this benefit is reduced, since by 2030 the potential to meet higher demand by making use of existing capital is less. In the long term, the Hydrogen Blending Option has lower costs; a key reason for this is that the ability of the electrolyser to operate at times of low electricity prices (and low demand and/or high supply) means that the increase in electricity sector costs in the Hydrogen Blending Options are lower than they are in the Electricity Switching Options.

- The NPV of the direct costs of the Hydrogen Blending Options with no storage or with pipeline storage are much higher than the NPV of the direct costs of the Hydrogen Blending Options with underground storage. As discussed, the reason is the need for additional electrolyser capacity and higher electricity sector costs without storage or with expensive storage.

- While the NPV of the direct costs of the 2030 options are lower than the NPV of the direct costs of the 2025 options, part of this difference is due to the fact that the increase in costs in the 2030 options occurs later in the period, so that there are fewer years of higher costs accounted for in the NPVs shown in Table 6. The NPV results in Table 7 only cover the period from 2030 to 2050 and shows that the direct costs of the 2030 options are still lower than those of the 2025 options, reflecting the benefit of waiting for lower capital costs for renewable electricity generation and electrolysers in 2030.
Table 6: NPV of cost difference against Base Case – from 2020 to 2050

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<tr>
<th>SCENARIO</th>
<th>PV OF NET BENEFIT AGAINST BASE CASE ($)</th>
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<td>Hydrogen Blending Option (2025)</td>
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Source: Frontier Economics

Table 7: NPV of cost difference against Base Case – from 2030 to 2050

<table>
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<tr>
<th>SCENARIO</th>
<th>PV OF NET BENEFIT AGAINST BASE CASE ($)</th>
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</tr>
<tr>
<td>Hydrogen Blending Option with Pipeline Storage (2025)</td>
<td>-$159 million</td>
</tr>
<tr>
<td>Hydrogen Blending Option no Storage (2025)</td>
<td>-$158 million</td>
</tr>
<tr>
<td>Electricity Switching Option (2025)</td>
<td>-$101 million</td>
</tr>
<tr>
<td>Hydrogen Blending Option (2030)</td>
<td>-$105 million</td>
</tr>
<tr>
<td>Hydrogen Blending Option with Pipeline Storage (2030)</td>
<td>-$159 million</td>
</tr>
<tr>
<td>Hydrogen Blending Option no Storage (2030)</td>
<td>-$165 million</td>
</tr>
<tr>
<td>Electricity Switching Option (2030)</td>
<td>-$121 million</td>
</tr>
</tbody>
</table>

Source: Frontier Economics

Depending on how the electricity switching cases are implemented, there may be additional appliance costs due to customers replacing operating gas appliances with new electric appliances. Based on the number of appliances that would likely need to be switched in the electricity switching options, and the cost of these appliances, the additional cost of replacing appliances in the electricity switching options...
could be between the low tens of millions of dollars and around a hundred million dollars. Accounting for this would materially increase the net increase in costs for the electricity switching options.
A ELECTRICITY MODELLING METHODOLOGY AND ASSUMPTIONS

We model long-term investment outcomes in Victoria and the rest of the NEM using our long-term optimisation model, WHIRLYGIG.

WHIRLYGIG is a long-term investment model for electricity markets. WHIRLYGIG relies on a detailed representation of the electricity system and, based on this, optimises total generation cost in the electricity market, calculating the least cost mix of existing generation plant and new generation plant options to meet demand. The model incorporates policy or regulatory obligations facing the generation sector, such as a renewable energy target, and calculates the cost of meeting these obligations. WHIRLYGIG provides a forecast of the least cost investment path as well as least cost dispatch. WHIRLYGIG provides an estimate of the long run marginal cost (LRMC) of electricity and the marginal cost of meeting any policy obligations. An overview of WHIRLYGIG is provided in Figure 47.

WHIRLYGIG includes a representation of demand and supply conditions in each of the regions of the NEM, including the capacity of interconnectors between the regions. WHIRLYGIG does not include existing intra-regional network constraints, largely because there is no robust way to forecast these network constraints in the long-term without detailed network modelling undertaken by the transmission network service providers.
Figure 47: WHIRLYGIG schematic

In order to model long-term investment and retirement decisions over the long-term modelling period, WHIRLYGIG models 80 representative demand points for each year, rather than the full 17,520 half hours of the year. WHIRLYGIG also models additional demand points that represent peak demand outcomes for a 1-in-10 year (POE10). These representative demand points are defined to capture a diverse range of outcomes for demand (ensuring we account for periods of high demand), solar PV generation and wind generation (ensuring we account for periods of low generation) across seasons. WHIRLYGIG includes dispatch of the power system for each one of these 80 representative demand points for each year, to ensure demand can be met at each point, having regard to the level of intermittent generation for that point.

Nevertheless, it is clear that modelling sequential half-hourly outcomes is important for a robust assessment of dispatch and prices in the context of a generation mix that increasingly consists of variable wind and solar generation. For this reason, we model dispatch and pricing making use of our half-hourly dispatch model – SYNC.

Modelling expected half-hourly dispatch and wholesale prices

We model dispatch and wholesale price outcomes in Victoria and the rest of the NEM using our electricity market dispatch model, SYNC.
SYNC is an electricity market dispatch model that focuses on detailed short-term (half-hourly) fluctuations in demand, supply and system constraints. SYNC relies on a detailed representation of the electricity system and, based on this, determines market-clearing dispatch and pricing outcomes. SYNC makes use of investment outcomes modelled in WHIRLYGIG and uses a long-term forecast of bidding patterns. The model focuses on factors that affect short term price fluctuations and volatility in the wholesale market. These include half-hourly fluctuations in demand and intermittent wind and solar generation, ramping constraints as well as start-up costs of different technologies. SYNC provides a dispatch and wholesale price forecast at a half-hourly level. An overview of SYNC is provided in Figure 48.

SYNC includes a representation of demand and supply conditions in each of the regions of the NEM, including interconnectors between the regions. SYNC does not include existing intra-regional network constraints, largely because there is no robust way to forecast these network constraints in the long-term without detailed network modelling undertaken by the transmission network service providers.

Once we have modelled SYNC, we test whether the results are consistent with the investment outcomes in WHIRLYGIG and, if not, adjust our WHIRLYGIG modelling accordingly and repeat our modelling process.

We note that this sequential modelling approach – with investment decisions modelled in a long-term model with a simplified demand duration curve and dispatch and wholesale prices modelled in a half-hourly dispatch model – is consistent with the modelling framework adopted by AEMO for its Integrated System Plan.
This section sets out the key input assumptions that we have used in our Base Case electricity market modelling.

Our Base Case consists of a series of “most likely” or central predictions for all inputs and assumptions. We draw on information published by the Australian Energy Market Operator (AEMO) as part of the development of the 2020 Integrated System Plan (ISP) for these Base Case assumptions.
Demand forecast

Our Base Case demand inputs are based on the central scenario of AEMO’s December 2019 update to its Integrated System Plan report, as shown in Figure 49 (for annual consumption) and Figure 50 (for annual maximum demand, for 50% probability of exceedance (POE) and 10% POE).

AEMO’s demand forecast takes into account the contribution by rooftop PV and non-utility battery to annual consumption and peak demand. In other words, its operational energy forecast excludes consumption met by rooftop PV, and accounts for rooftop PV and non-utility battery’s contribution to peak demand. In addition, AEMO also forecasts energy consumption that is “saved” due to improvements in energy efficiency measures. Our Base Case demand forecast reflects the neutral forecast for these components as part of operational demand forecasts.

Figure 49: Energy consumption forecast (Operational, sent-out, GWh)

Source: AEMO 2020 ISP input assumptions with Frontier Economics extrapolation post 2037/38.
Figure 50: Maximum demand forecast (Operational, sent-out, MW)

Source: AEMO 2020 ISP input assumptions with Frontier Economics extrapolation post 2037/38.

**Generation options**

The options we include for new generation plant are those that are included in the CSIRO’s Electricity Generation Technology Cost Projections report, which is the source of capital costs proposed in AEMO’s ISP consultation report.

These new generation plant options are:

- High Efficiency, Low Emissions Black coal
- Nuclear
- CCGT
- OCGT
- Biomass - steam turbine
- Utility PV
- Wind - onshore
- Solar thermal with storage (6hrs storage)
- Large Scale Battery Storage (2hrs storage)
- Pumped Hydro (6hrs storage).

Consistent with CSIROs report we are assuming that all of these technologies will be ready for commercial deployment during the modelling period. We dont consider this to be an unrealistic assumption: each of these technologies have already been deployed on a commercial scale somewhere in the world.
We have retained nuclear as an option but recognise that constructing a nuclear power plant is not consistent with current policy.

**Gas prices**

Our gas price forecasts are sourced from AEMO’s ISP modelling assumptions.\(^{15}\)

The average combined cycle gas turbine (CCGT) gas prices used in our modelling for each region are shown in **Figure 51**. The corresponding open cycle gas turbine (OCGT) gas prices are 50 per cent higher.

**Figure 51**: Average gas prices for CCGT plants

\[\text{Gas prices (delivered, $/GJ, real 2018/19)}\]

\[\text{Financial year (ending 30th June)}\]

Source: AEMO 2019 ISP modelling assumptions

**Capital Costs**

The capital costs for new entrant power station are based on CSIRO’s two-degree scenario in its Electricity Generation Technology Cost Projections report, which is the source of capital costs proposed in AEMO’s ISP consultation report.

**Figure 52** shows the capital cost used in our Base Case for thermal and renewable technologies.

While the cost of traditional and mature gas and coal technologies are predicted to remain stable, there are significant cost reductions in new renewable technologies such as solar and battery.

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\(^{15}\) AEMO, *Integrated System Plan modelling assumptions*. Available here: 
These capital costs are used in all our modelling scenarios.

**Figure 52:** Capital costs

![Graph showing capital costs](image)

*Source: AEMO 2019 ISP modelling assumptions*

### Renewable and climate change policies

#### Emission target

Consistent with AEMO’s 2019 ISP assumptions, we do not model an explicit emissions constraint. All emissions reduction occurs from other national targets (LRET, VRET and QRET) and any scheduled or modelled coal retirements.

**LRET**

We model the legislated Large-scale Renewable Energy Target (LRET), which will reach 33 TWh in 2020 in all scenarios. We model this as a national target.

Due to the large amount of committed Large-scale Generation Certificate (LGC) producing generators entering the market, no LGC price is provided by the model. In other words, the marginal cost of meeting this target is zero, since there is enough committed capacity to achieve it already.
Renewable energy targets in Victoria and Queensland

We model the Victorian Renewable Energy Target (VRET), which seeks to source 40 per cent of the state’s energy generation from renewable plant\textsuperscript{16} by 2025 and the Queensland energy pathway to achieving 50 per cent renewable energy generation (QRET) by 2030.

\textbf{Figure 53} and \textbf{Figure 54} show the additional capacity provided by utility level wind and solar PV plant under VRET\textsuperscript{17} and QRET\textsuperscript{18} that we include in our modelling. These are additional to the contribution to the target made by forecast rooftop PV, existing renewable plant and plant already in the pipeline.

\textbf{Figure 53:} Additional utility QRET capacity

![Graph showing additional utility QRET capacity](image)

\textit{Source: Frontier Economics analysis}

\textsuperscript{16} Including rooftop PV and existing hydro.


Indicative analysis of blending hydrogen in gas networks

**Figure 54:** Additional utility VRET capacity

![Graph showing additional utility VRET capacity](image)

*Source: Frontier Economics analysis*

**Plant retirement**

In all scenarios we model the retirement of existing black and brown coal baseload plant. We assume that these stations will not operate beyond the assumed technical end life as in AEMO’s 2019 ISP consultation report, shown in Figure 55. Most of these stations will reach their 50-year technical life limit by these assumed end years.

In addition, we model economic retirement where it is not economic for a plant to remain operating up to these retirement dates.
Figure 55: Announced or technical last year (inclusive) of operation of baseload coal plant

Source: AEMO 2019 ISP modelling assumptions
Our indicative analysis of the economics of blending hydrogen into Australian gas distribution networks is not intended to identify or model specific investments at specific locations. Nevertheless, it is useful to consider whether AGN’s distribution network in Victoria is likely to be well located for injection of hydrogen.

Our view is that AGN’s distribution network in Victoria is likely to be well located for injection of hydrogen if there are locations at which existing metered injection points on the gas distribution network are located in reasonable proximity to existing electricity transmission lines and existing generation plant. We are assuming that locating the hydrogen production facility close to an existing injection point will enable injection of hydrogen to the gas distribution network that will achieve a relatively consistent blend of natural gas and hydrogen across the network. In the event that hydrogen needs to be injected at a number of individual injection points to maintain a relatively consistent blend, there would be additional cost of transporting hydrogen from the point of production to these various injection points. Given that electricity costs are a key component of the costs of an electrolyser, we assume that an electrolyser will seek to be directly connected to a transmission line in order to achieve lower electricity prices.

Our high level analysis of network maps for AGN’s distribution network (as shown in Figure 56) and for the electricity transmission network in Victoria (as shown in Figure 57) suggests that this is the case.

For instance, comparing Figure 56 and Figure 57 shows the following:

- AGN’s Mornington Operations Area is located in the same area as the major transmission lines that run from the brown coal generators in the La Trobe Valley into Melbourne. There are a number of existing metered injection points within the Mornington Operations Area that are located in reasonable proximity to these transmission lines. There are also existing metered injection points in reasonable proximity to the brown coal generators in the La Trobe Valley.
- AGN’s Thomastown Operations Area has a number of existing metered injection points towards the northern end of Melbourne, in reasonable proximity to the transmission lines through this area.
Figure 56: AGN’s Victorian gas network map

Source: AGN
Figure 57: Transmission infrastructure map

Source: AEMO