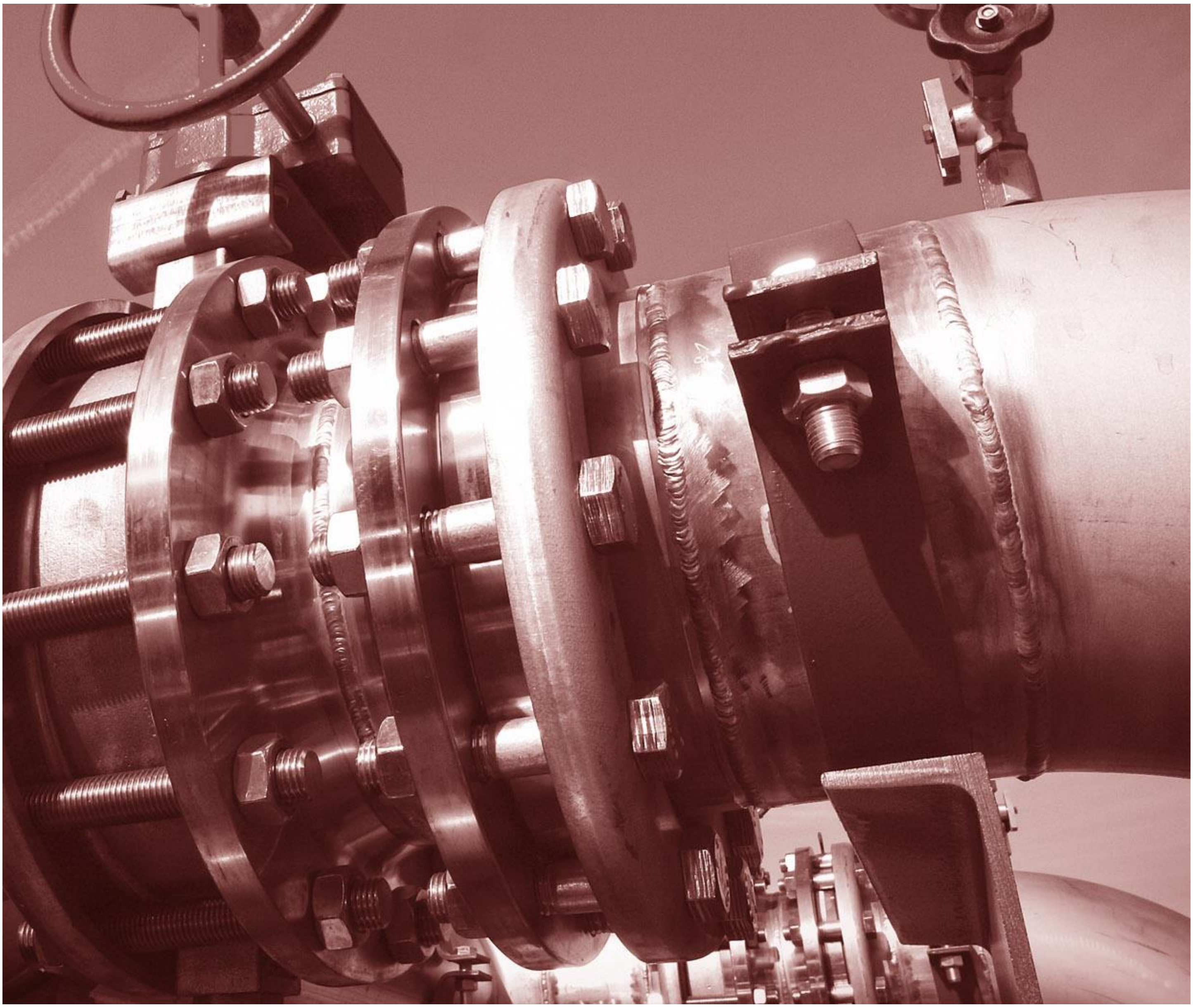
THE BENEFITS OF GAS INFRASTRUCTURE TO DECARBONISE AUSTRALIA

A REPORT FOR THE AUSTRALIAN GAS INDUSTRY

17 SEPTEMBER 2020



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EXECUTIVE SUMMARY

Objective of study

Frontier Economics has been engaged by Australian gas industry associations to undertake a study on the benefits of gas infrastructure to decarbonise Australia.

The objectives of this study are to determine and document an estimate of the value of gas infrastructure in 2050, accounting for Australia's carbon-emission commitments. Specifically, this includes:

1. Assessing the challenge in decarbonising Australia for the generation, storage and transport of energy
2. Developing and considering gas infrastructure scenarios for overcoming the challenges of decarbonisation
3. Valuing each gas infrastructure scenario
4. Considering policy implications for realising the value of the optimal gas infrastructure scenario

Scenarios and assumptions

The energy supply options that we assess are the following:

- **Base Case** – represents our view on a business as usual outcome for the electricity and gas sectors in 2050. The Base Case is the scenario against which costs and benefits in the other scenarios are compared.
- **Electrification scenario** – under this energy supply option, the intention is that all end-use natural gas consumption is replaced by customers switching from gas supply to electricity supply. However, as we discuss, our review suggests that complete electrification of gas consumption is likely to be impractical, particularly for industrial customers. For that reason, for industrial customers the Electrification scenario involves a mix of:
    - use of grid-sourced electricity
    - use of distributed electricity generation and storage
    - supply of heat through distributed solar thermal plant
    - use of hydrogen produced from on-site electrolysers supplied with grid-sourced electricity.

  Under each of these options end-use customers will no longer make use of gas infrastructure to meet their energy needs.
- **Renewable Fuels scenario** – under this energy supply option, hydrogen produced using alkaline electrolysis replaces all end-use natural gas consumption. Replacement occurs to ensure that the energy content of hydrogen is equal to the energy content of displaced natural gas.
- **Zero-carbon Fuels scenario** – under this energy supply option, hydrogen produced using steam methane reforming (SMR) of natural gas with carbon, capture and storage replaces all end-use natural gas consumption. The scenario is otherwise equivalent to the Renewable Fuels scenario.

Hydrogen use in the scenarios is used to represent net-zero carbon fuels. It may be that other net-zero carbon fuels, such as biogas or renewable gas could be used for some applications by 2050, although our scenarios have not specifically investigated these alternatives.

The assumptions that we have used to develop and analyse these scenarios are based on publicly available data primarily developed and published by market operators, regulators and government:

- We have relied on forecasts from the Australian Energy Market Operator (AEMO) to forecast electricity consumption and gas consumption in the Base Case.
- We have relied on industrial energy use data published by Department of the Environment and Energy as part of the *Australia Energy Statistics* to forecast gas consumption by industry in the Base Case.
- We have relied on various reports for the Australian Renewable Energy Agency (ARENA) to determine heat and feedstock requirements for industrial gas customers and to identify alternatives to gas for these industrial customers.
- We have relied on input assumptions developed by AEMO to undertake our electricity market modelling.
- We have relied on estimates from AEMO and the Australian Energy Regulator (AER) for the costs of electricity and gas transmission and gas production.
- We have relied on estimates from the International Energy Agency for estimates of the costs of producing, transporting and storing hydrogen.

Methodology

The methodology that we have adopted to estimate the costs and benefits of each scenario is, briefly, as follows:

- We estimate changes in natural gas consumption, electricity consumption and hydrogen consumption for each of the scenarios that we investigate. This first step essentially consists of determining how switching away from natural gas – as an end use fuel – will take place in each of the three scenarios that we investigate.
- Based on these changes in natural gas consumption, and assumptions about the costs of producing natural gas and transporting natural gas on the transmission and distribution networks, we can estimate changes in the costs of producing and transporting natural gas.
- Based on these changes in electricity consumption, and modelling of electricity market outcomes, we can estimate changes in the costs of generating and storing electricity. Using these same changes in electricity consumption, and assumptions about the costs of transporting electricity on the transmission and distribution networks, we can estimate changes in the costs of transporting electricity.
- Based on these changes in hydrogen consumption, and assumptions about the cost of hydrogen production, transmission and storage, we can estimate changes in the costs of producing, transporting and storing hydrogen.
- Having estimated each of these cost categories, we determine the net present value of the difference in annual costs in 2050 between each of the scenarios and the Base Case.

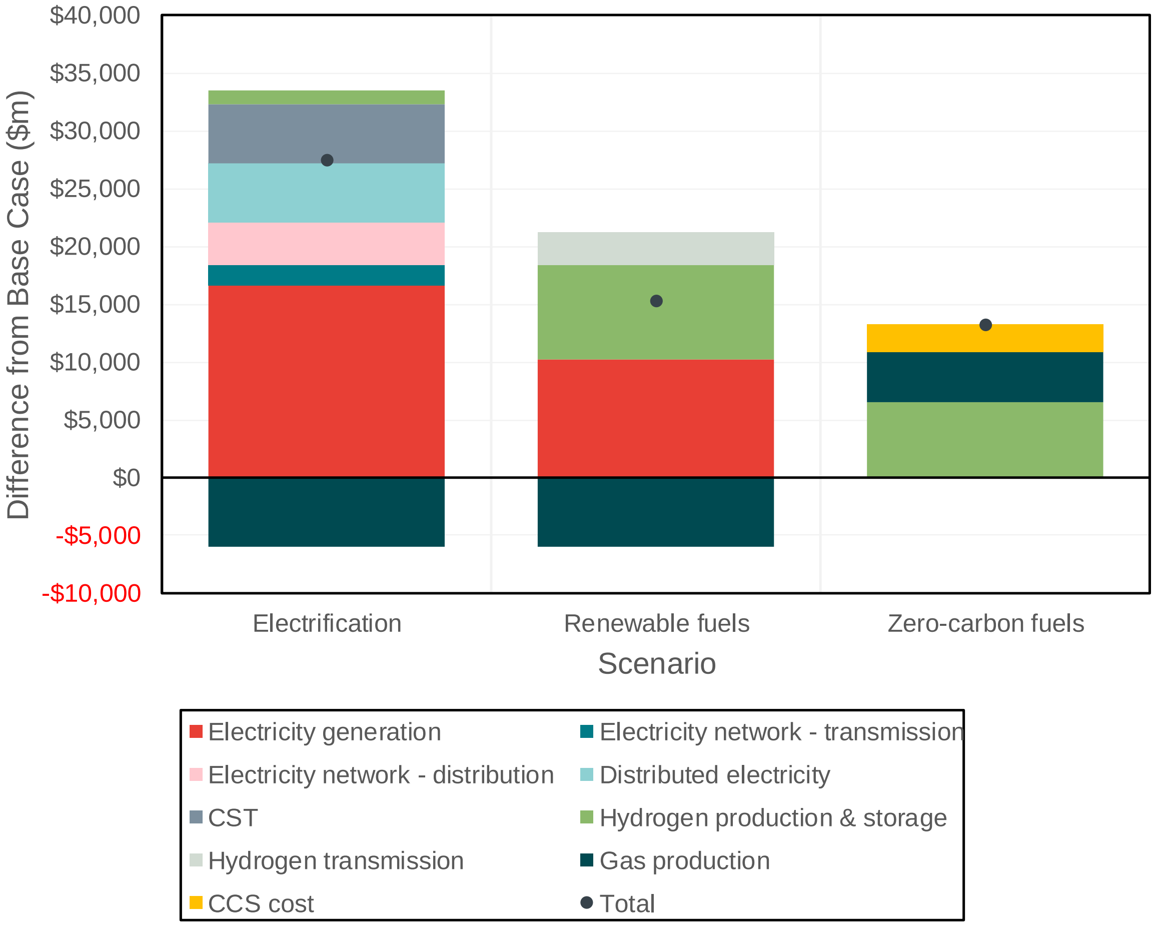
Major conclusions and policy outcomes

Based on the results of our analysis, we reach the following conclusions:

- Each of the three scenarios that we examine can reach net zero emissions from the stationary energy sector in 2050 (although entail additional costs in doing so). In contrast, in the Base Case, there are continued emissions associated with the end-use of natural gas that would need to be offset to reach net zero emissions.

- Gaseous fuels are essential as industrial feedstock in all of the scenarios. If gaseous fuels (either natural gas, hydrogen, biogas or renewable methane) are not available, the industries that rely on this feedstock would not be viable.
- For industries that use gas for heat, there is uncertainty about the practicality of switching these energy requirements entirely to grid-sourced electricity. Particularly for higher temperature requirements, it is unclear that grid sourced electricity is a practical alternative for all applications.
- Each of the three scenarios that we consider is more costly in 2050 than the Base Case (that is, incremental costs relative to the Base Case are positive). This is consistent with the expectation that shifting away from our Base Case of consumption of electricity and gas to a scenario that meets net zero emissions from the stationary energy sector will be costly. This is illustrated in the results of our cost-benefit analysis presented in **Figure 1**, which shows differences in annual costs in 2050 relative to the Base Case.
- Of the three scenarios, **the most costly is the Electrification scenario**. There are two key reasons that this scenario is costly. First, even in 2050, the costs of generation to meet the energy needs of industrial customers using gas in the Base Case are significant. Second, there are significant additional electricity network costs associated with the Electrification scenario. Meeting the energy needs for residential, commercial and some industrial customers that are currently meet by natural gas, using grid-sourced electricity, and doing so while continuing to supply Base Case electricity demand, requires additional capacity on the transmission and distribution networks, at material additional cost.
- **The Renewable Fuels scenario is lower cost than the Electrification scenario**. What we see is that the combined cost of building electrolysers and supplying them with electricity in order to replace all gas consumption is lower than the combined cost of the mix of grid-sourced electricity, distributed electricity generation and storage, solar thermal heat generation and hydrogen that is required in the Electrification scenario. While there are significant additional costs of electricity production and of hydrogen production, transmission and storage in the Renewable Fuels scenario, the ongoing use of the gas distribution network in this scenario means that there are not additional costs of energy distribution in this scenario (as there are in the Electrification scenario). Since the operation of electrolysers can be optimised to times of lowest cost electricity, the average cost of additional electricity is lower in the Renewable Fuels scenario than the Electrification scenario.
- **The Zero-carbon Fuels scenario is lower cost than both the Renewable Fuels scenario and the Electrification scenario**. The cost saving for the Zero-carbon Fuels scenario relative to the Renewable Fuels scenario is largely driven by the fact that the gas used by the SMR is lower cost than the electricity used in the electrolyser. The fact that the gas delivered to the SMR can make use of existing gas transmission assets (which are no longer required for delivering gas to end customers) whereas the delivery of hydrogen from the electrolyser is assumed to require new investment in hydrogen transmission pipelines, also accounts for some of the cost saving. Against this, the SMR requires additional cost to capture and store carbon, but this additional cost does not outweigh the savings from using gas rather than electricity.

Figure 1: Cost-benefit analysis summary by components ($2020)



Source: Frontier Economics' modelling

Based on this result, we conclude the following:

- Making continued use of existing assets to deliver energy, such as the existing gas transmission and distribution network, where possible, can help avoid the material costs of investing in new assets to deliver energy, such as augmentation of the electricity transmission and distribution network.
- Our finding that both the Renewable Fuels scenario and the Zero-carbon Fuels scenario is lower cost than the Electrification scenario suggests that there is value in continuing to make use of Australia's gas network and Australia's natural gas resources to deliver gaseous fuels to end-use customers.
- Our finding that both the Renewable Fuels scenario and the Zero-carbon Fuels scenario is lower cost than the Electrification scenario suggests that policies to achieve net zero emissions should be broad-based and should not focus solely on promoting the electrification of all stationary energy end-use.
- There is significant uncertainty about technological developments and costs over the period to 2050. This means that the actual costs of the scenarios that we have examined will change over time, and new alternative scenarios will emerge over time. Policies to achieve net zero emissions that are broad-based, rather than focused solely on promoting the electrification of all stationary energy end-use, will enable energy sector participants and their customers to respond flexibly to these technology and cost changes to lower costs.

1 INTRODUCTION

Frontier Economics has been engaged by Australian gas industry associations to undertake a study on the benefits of gas infrastructure to decarbonise Australia.

1.1 Background

Australia has committed to reducing its carbon emissions by 26-28 per cent on 2005 levels by 2030, as part of the Paris Agreement. Alongside this, each state government in Australia has target, objective or aspiration of achieving net zero emissions by 2050.

Within this context, the gas industry is interested in understanding the role for gas infrastructure in the future, having regard to options for reducing carbon emissions, including options for the development of a domestic hydrogen industry.

The objectives of this project are to determine and document an estimate of the value of gas infrastructure in 2050, accounting for Australia's carbon-emission commitments. Specifically, this will include undertaking the following stages of work:

1. Assess the challenge in decarbonising Australia for the generation, storage and transport of energy
2. Develop and consider gas infrastructure scenarios for overcoming the challenges of decarbonisation
3. Value each gas infrastructure scenario
4. Consider policy implications for realising the value of the optimal gas infrastructure scenario

1.2 Frontier Economics' engagement

We have been engaged to consider the expected costs and benefits of substituting the end-use of natural gas with alternative fuel sources – specifically hydrogen or renewable electricity – on a path to decarbonisation. 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.
- The cost of hydrogen transmission pipelines.

Our analysis is to focus on outcomes in Australia in 2050, and to assume that the Australian energy sector would be 100% carbon neutral by 2050. Our analysis does not address transition from 2020 to 2050, but deals only with outcomes in 2050. The analysis focusses on the domestic gas industry and does not assess implications for the LNG industry or possible development of a hydrogen export industry.

We have been engaged to examine three separate scenarios for 2050 that are consistent with net zero emissions by 2050 for the electricity and gas sectors:

- **Electrification scenario**: Replacement of end-use of gas with electricity with net zero emissions. As we discuss in this report, there are significant practical difficulties with this scenario which has led us to investigate a scenario that involves partial switching to electricity.

- **Renewable Fuels scenario**: Replacement of end-use of gas with hydrogen produced through electrolysis.
- **Zero-carbon Fuels scenario**: Replacement of end-use of gas with hydrogen produced through steam methane reforming of natural gas with carbon, capture and sequestration.

The intention is to compare the relative economic costs of these three alternative paths to meeting energy requirements that are forecast to be met by the electricity and gas sectors in the base case, but to do so while meeting a target of net zero emissions.

1.3 About this report

This report is structured as follows:

- Section 2 describes the Base Case, which is the scenario against which costs and benefits in the other scenarios are compared.
- 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.

2 THE BASE CASE

This section describes the Base Case in 2050. The Base Case represents our view on a business as usual outcome for the electricity and gas sectors in 2050. The Base Case is the scenario against which costs and benefits in the other scenarios are compared.

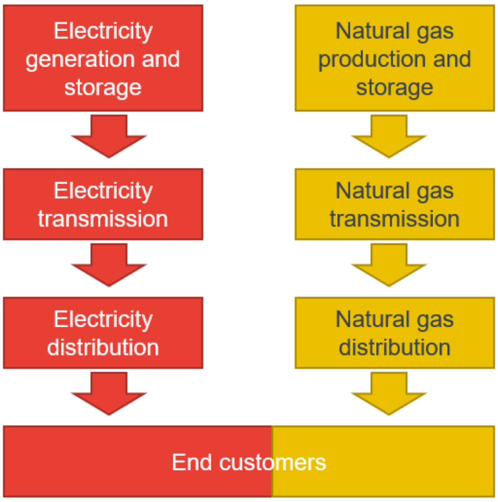
2.1 Base Case energy supply

Figure 2 provides a depiction of the energy supply to gas customers. All gas customers 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 2: Energy supply to end customers – Base Case



Source: Frontier Economics

The Base Case is not based on the assumption that all energy supply will be net zero emissions by 2050. The Base Case is based on the assumption that electricity supply in 2050 will be net zero emissions (as are the other scenarios that we examine). However, the Base Case is based on the assumption that gas will continue to be supplied to end customers (including residential, commercial and industrial customers) and that there will be carbon emissions associated with this end use of gas. As a result, each of the scenarios that we investigate will result in a reduction in carbon emissions relative to the Base Case.

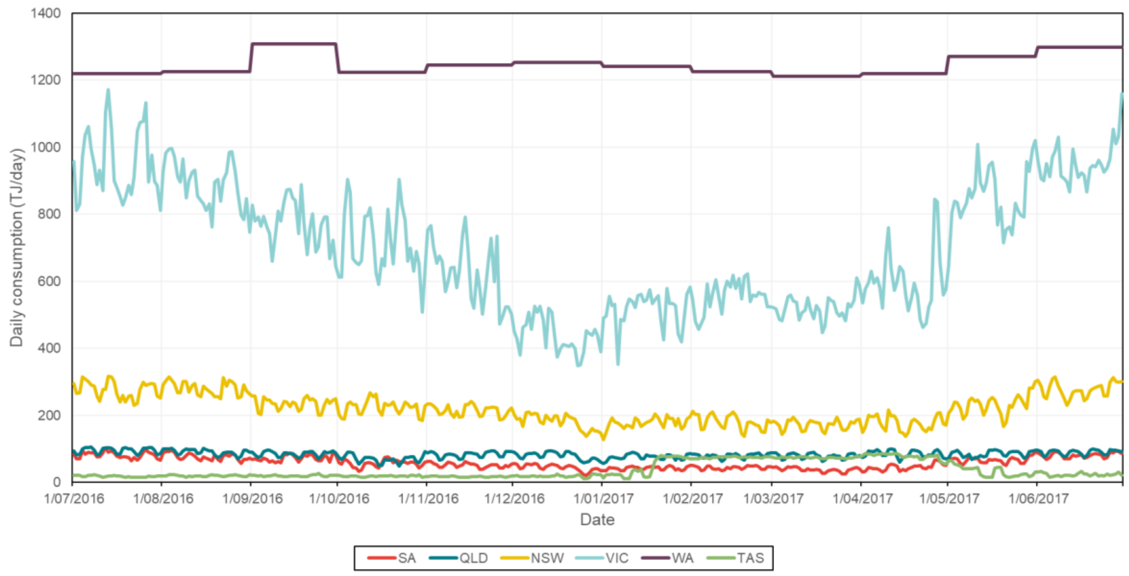
2.2 Base Case end-use natural gas consumption in 2050

To estimate the amount of end-use natural gas consumption in the Base Case we need forecasts of natural gas consumption in Australia in 2050. Because the timing of energy supply affects the costs of energy supply, we need these forecasts to be daily forecasts of natural gas consumption. It is also important that the forecasts are split by end use, as this will affect how some of the gas is replaced.

First, we develop residential, commercial and industrial daily forecasts of natural gas consumption as follows:

- We begin with a profile for daily gas consumption for 2050 for each state, which can be seen in **Figure 3**. 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. We use the historical data from financial year 2016/17, because this is the historical period 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 adjust the historical daily gas consumption for each region for financial year 2016/17 to account for forecast changes in annual gas consumption until 2050. The forecasts that we use are from AEMO's 2019 GSOO, which are shown in **Figure 4**; 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. It is important to note that this is only for residential, commercial and industrial customers. The gas demand from gas-powered generation is accounted for when we undertake separate electricity market modelling – given that we are assuming the electricity sector must meet a target of net zero emissions by 2050, and given the cost trajectories for renewable generation and for storage, our electricity sector modelling – as described in Appendix A – indicates that there will be no material use of gas for electricity generation in 2050 in any case. Given that our report focuses on domestic end-use of gas, our analysis does not consider LNG exports.

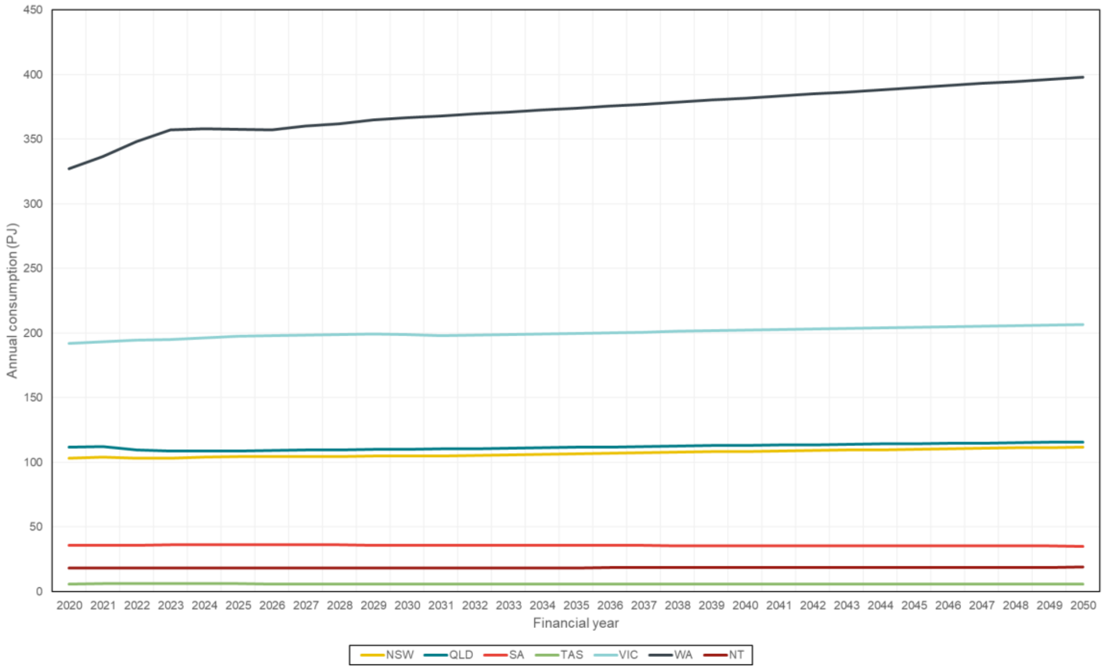
Figure 3: Estimated daily gas consumption for states in Australia for 2017/18



Source: Frontier Economics analysis of data from AEMO

Note: The Australian Capital Territory is included with NSW.

Figure 4: Forecast annual gas consumption for states in Australia



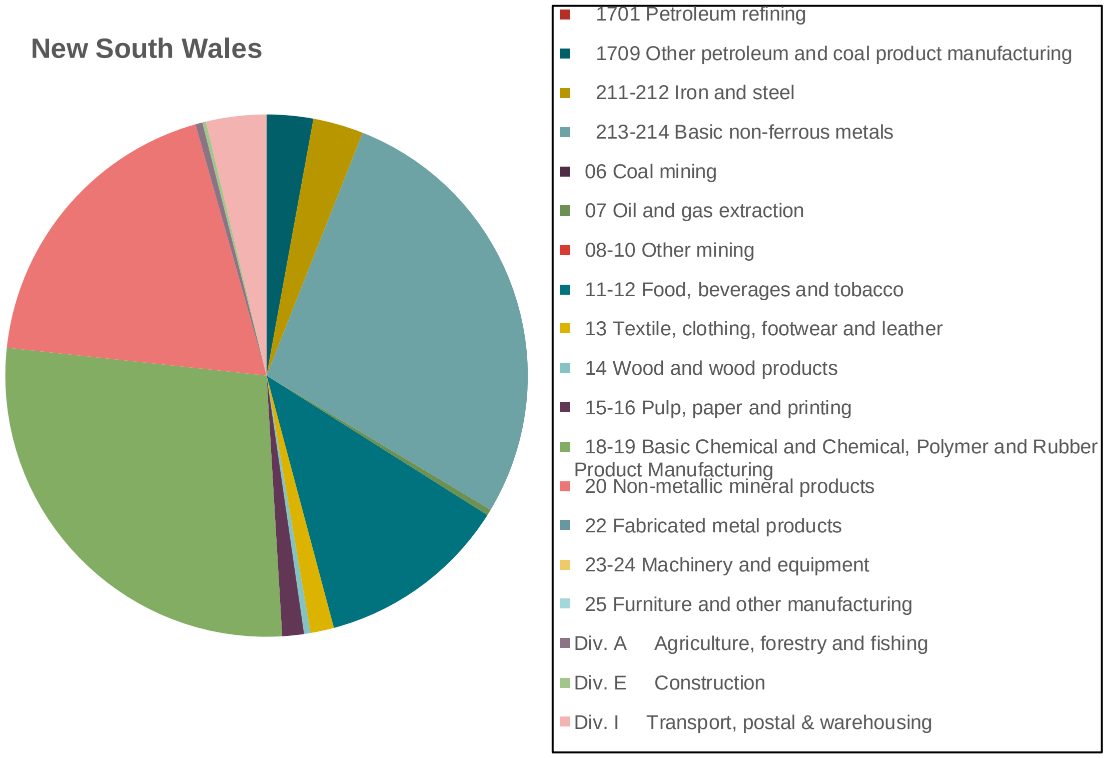
Source: Frontier Economics analysis of data from AEMO

Since we do not have public forecasts of long-term gas demand for the Northern Territory, we assume that existing gas consumption for industrial purposes remains constant at current levels (and existing gas consumption for gas generation is displaced by a shift to renewable generation and storage).

Industrial gas use by sector

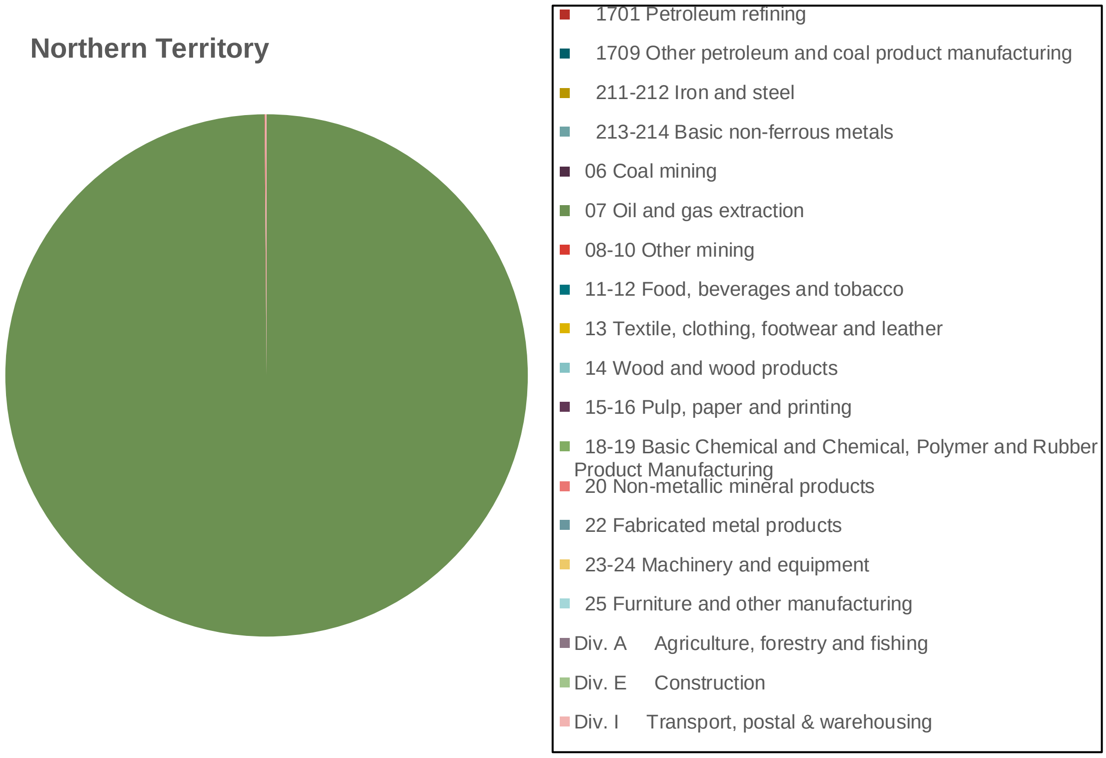
We can combine these estimates with data on industrial gas use by sector, published by the Department of the Environment and Energy as part of the *Australia Energy Statistics*. These statistics provide information on gas use by the industrial sector in 2017/18 for each jurisdiction in Australia, as summarised in **Figure 5** through **Figure 11**. **Figure 5** through **Figure 11** show the share of total industrial gas use in each jurisdiction accounted for by each industrial sector. These estimates are then rolled forward to estimates for 2050 based on forecast growth in industrial gas use from AEMO (as discussed in Section 4.1.1). It is important that the forecasts are split by industrial sector, as this will affect how some end-use of gas is replaced with alternatives.

Figure 5: Proportion of industrial gas use by sector in 2017/18 – New South Wales



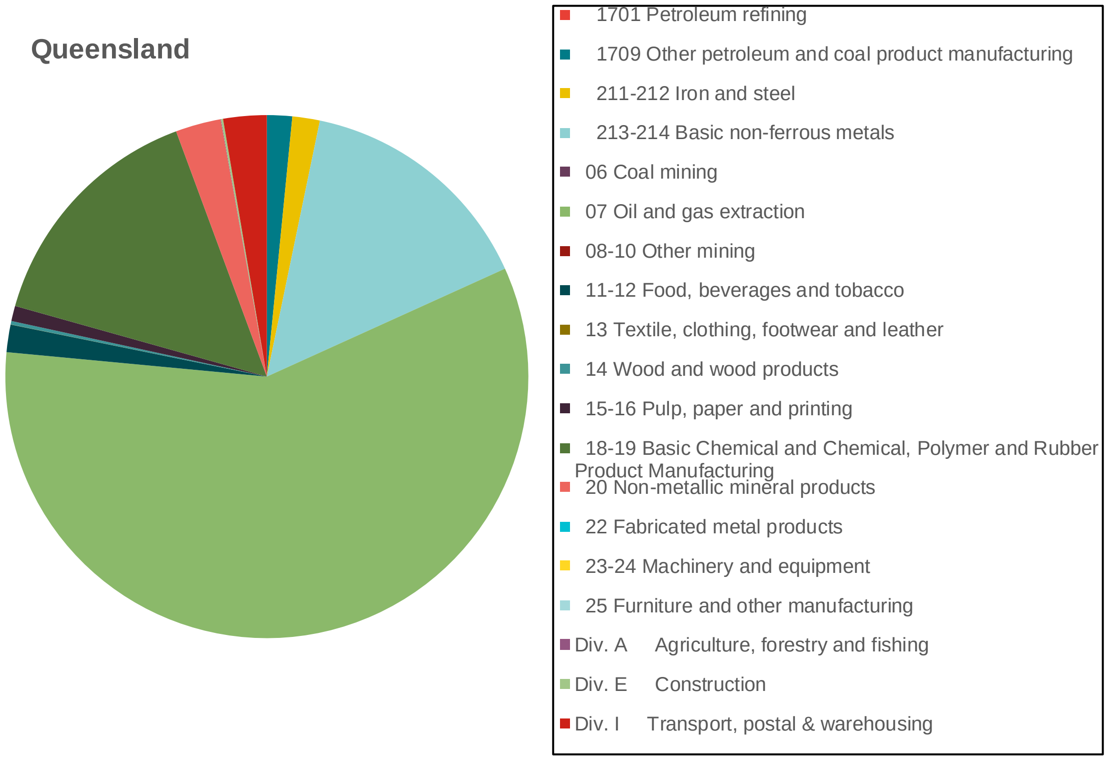
Source: Australia Energy Statistics, Table F. Note: includes ACT.

Figure 6: Proportion of industrial gas use by sector in 2017/18 – Northern Territory



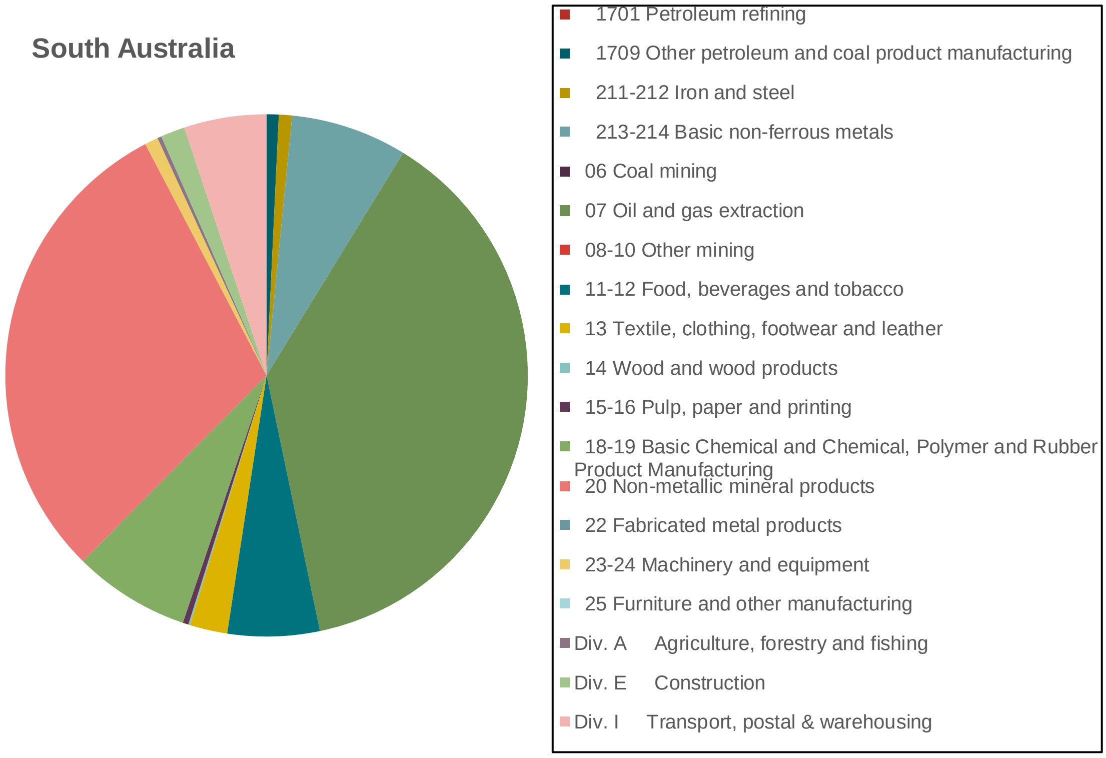
Source: Australia Energy Statistics, Table F.

Figure 7: Proportion of industrial gas use by sector in 2017/18 – Queensland



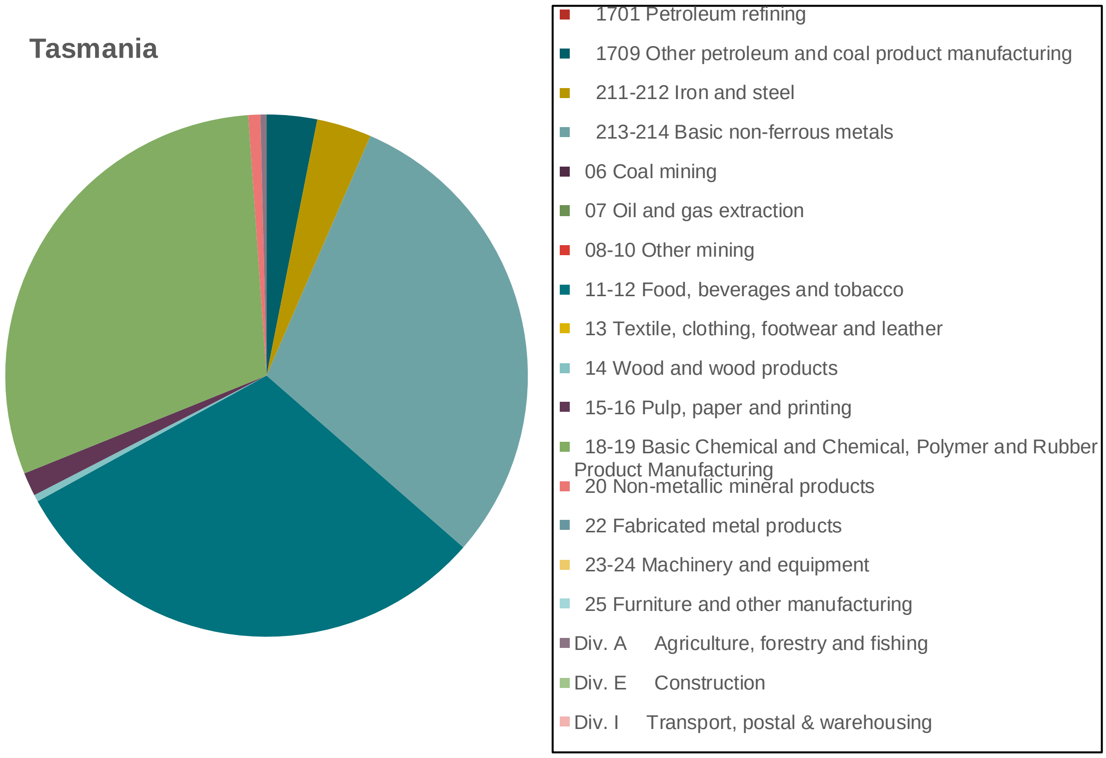
Source: Australia Energy Statistics, Table F.

Figure 8: Proportion of industrial gas use by sector in 2017/18 – South Australia



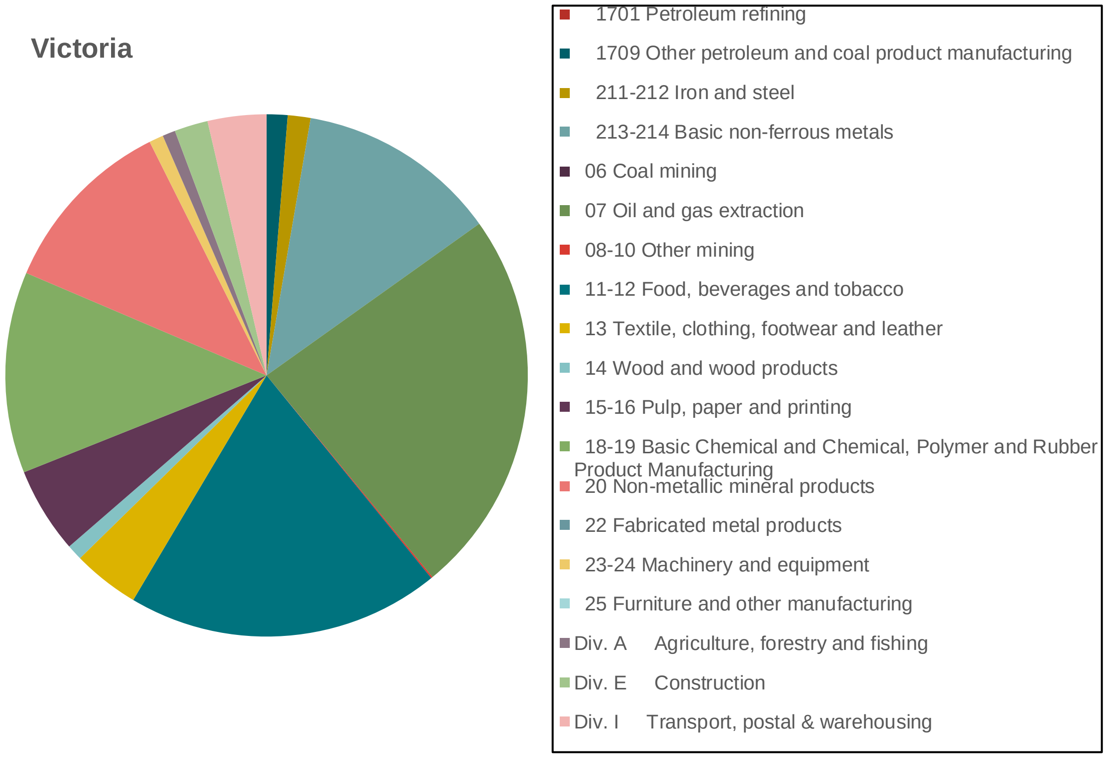
Source: Australia Energy Statistics, Table F.

Figure 9: Proportion of industrial gas use by sector in 2017/18 – Tasmania



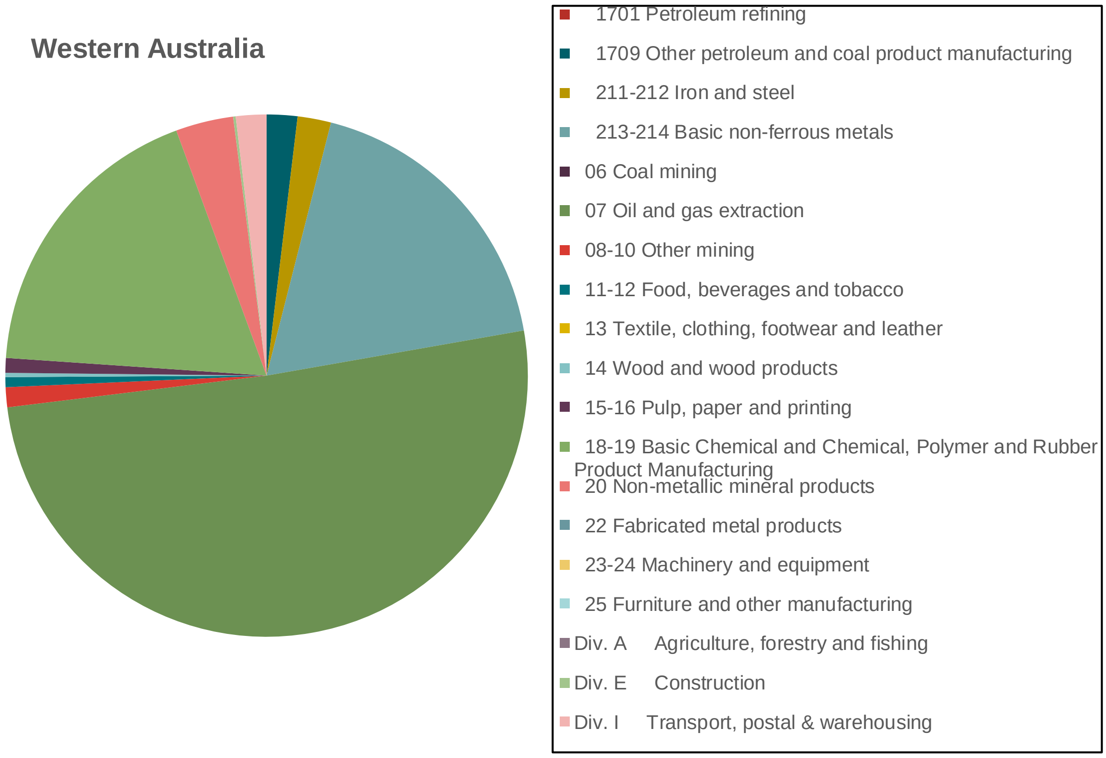
Source: Australia Energy Statistics, Table F.

Figure 10: Proportion of industrial gas use by sector in 2017/18 – Victoria



Source: Australia Energy Statistics, Table F.

Figure 11: Proportion of industrial gas use by sector in 2017/18 – Western Australia



Source: Australia Energy Statistics, Table F.

2.3 Base Case electricity supply

We model outcomes for the electricity sector in the Base Case (and ultimately for the scenarios) using our wholesale electricity market 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. 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 Renewable Fuels scenario and the Electrification scenario.

Our Base Case modelling for *WHIRLYGIG* uses a set of standard input assumptions, which are, for the most part, aligned with the input assumptions used by the Australian Energy Market Operator (AEMO) for the Integrated System Plan (ISP). We include a constraint to ensure that in 2050 the electricity sector achieves net zero emissions. More detail on our modelling approach and modelling assumptions are provided in Appendix A.

3 IMPACTS OF ENERGY SUPPLY OPTIONS

In order to identify the costs and benefits of the energy supply options that we are investigating in our 3 scenarios, it is useful to first map the impacts of each of these scenarios on each stage of the relevant energy supply chain.

This section defines the energy supply options we are investigating in our 3 scenarios 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 discussed, the energy supply options that we assess are the following:

- **Electrification scenario** – under this energy supply option, the intention is that all end-use natural gas consumption is replaced by customers switching from gas supply to electricity supply. However, as we discuss, our review suggests that complete electrification of gas consumption is likely to be impractical, particularly for industrial customers. For that reason, for industrial customers the Electrification scenario involves a mix of:
  - use of grid-sourced electricity
  - use of distributed electricity generation and storage
  - supply of heat through distributed solar thermal plant
  - use of hydrogen produced from on-site electrolysers supplied with grid-sourced electricity.

  Under each of these options end-use customers will no longer make use of gas infrastructure to meet their energy needs.
- **Renewable Fuels scenario** – under this energy supply option, hydrogen produced using alkaline electrolysis replaces all end-use natural gas consumption. Replacement occurs to ensure that the energy content of hydrogen is equal to the energy content of displaced natural gas. We have assumed that electrolysers generally will be located close to generation sites with a new network of hydrogen transmission pipelines that transport hydrogen to existing natural gas distribution networks. These distribution networks can be used to supply hydrogen to residential, commercial and industrial customers. For industrial customers that are currently directly connected to a gas transmission pipeline, we have assumed that by 2050 they will likewise be directly connected to a hydrogen transmission pipeline.
- **Zero-carbon Fuels scenario** – under this energy supply option, hydrogen produced using steam methane reforming of natural gas with carbon, capture and storage replaces all end-use natural gas consumption. We have assumed that the hydrogen production plant will be located near to the connection points with the existing natural gas distribution networks so that the existing network of transmission pipelines can be used to supply the hydrogen production plant and the existing gas distribution network can be used to supply customers.

Hydrogen use in the scenarios is used to represent net-zero carbon fuels. It may be that other net-zero carbon fuels, such as biogas or renewable gas could be used for some applications by 2050, although our scenarios have not specifically investigated these alternatives.

We compare outcomes for these three energy supply 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 Electrification scenario – energy supply and impacts

The Electrification scenario brings about some changes to the energy supply to customers relative to the Base Case (which is discussed in Section 2.1). Our research, discussed further in Section 4, suggests that to meet energy needs currently supplied by gas, complete reliance on grid-sourced electricity is unlikely, particularly for industrial customers. Instead, in the Electrification scenario we assume that customers rely on a mix of:

- use of grid-sourced electricity
- use of distributed electricity generation and storage
- supply of heat through distributed solar thermal plant
- use of hydrogen produced from on-site electrolysers supplied with grid-sourced electricity.

Figure 12 provides a depiction of the energy supply to gas customers under the Electrification scenario.

Based on this, there are four important changes under the Electrification scenario compared to the Base Case:

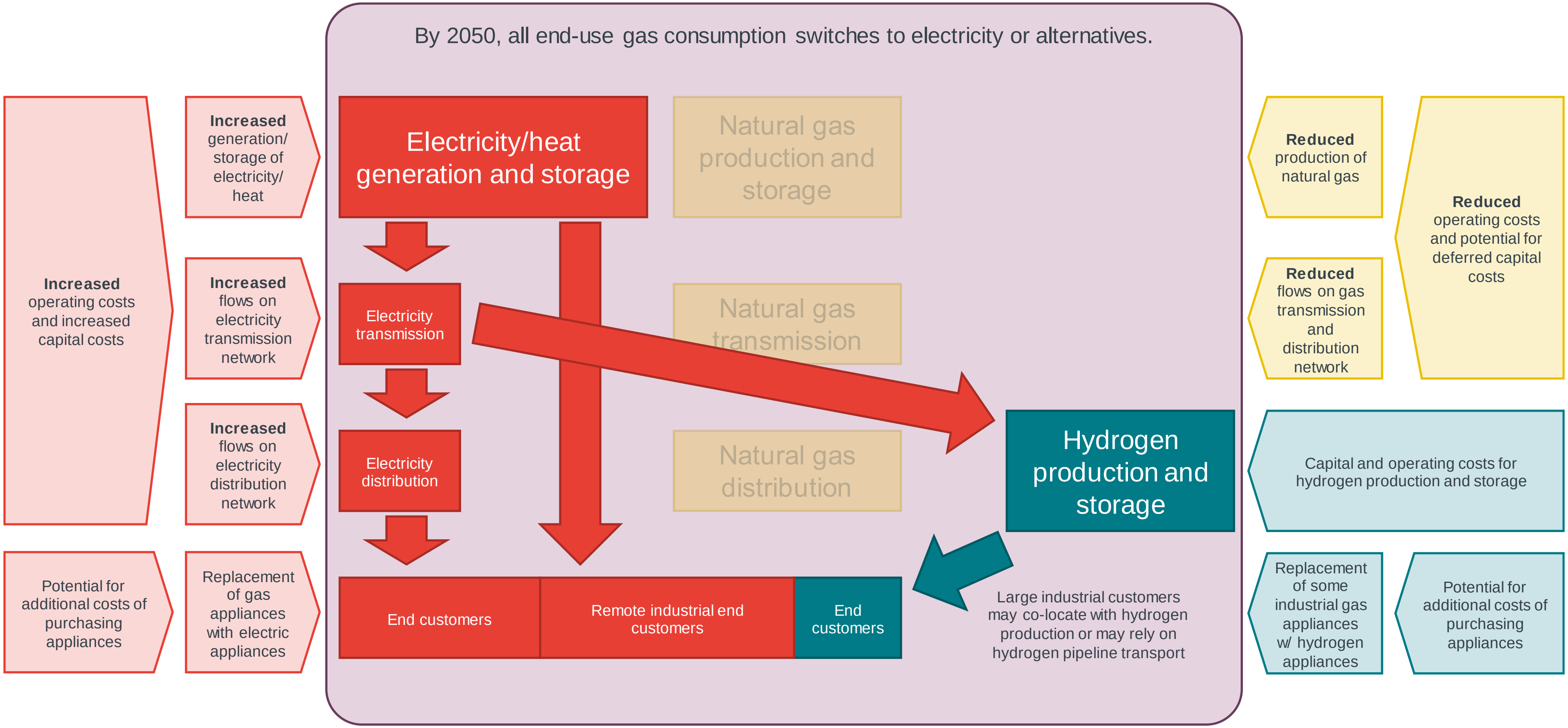
- Switching from gas to electric appliances for residential and commercial customers, and for some industrial customers, *increases* the need to generate and transport grid-sourced electricity.
- Switching from gas to distributed generation and storage for certain industrial purposes and for remote sites *increases* the need for 'on-site' generation of electricity or heat.
- Switching from gas to hydrogen for certain industrial purposes – for high temperature requirements or feedstock requirements – *requires* production of hydrogen.
- Switching from gas to these alternatives, *decreases* the need to produce and transport natural gas.

Figure 12 also highlights the impacts – and corresponding direct supply chain costs and benefits – of the changes in energy supply arrangements in the Electrification scenario:

- For the *electricity supply sector*, switching from gas to electric appliances by residential and commercial customers, and by some industrial customers, will lead to an increase in the generation, storage, 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. This increase in electricity generation, transmission and distribution would be expected to result in an increase in total capital and operating costs.
- For industrial customers switching from gas to *'on-site' generation and storage* of electricity or heat will lead to an increase in capital and operating costs.
- For the *hydrogen supply sector*, switching from gas to hydrogen by some industrial customers will lead to an increase in production of hydrogen. This increase in hydrogen production will require an increase in electricity supply (further increasing costs in the electricity supply sector) and result in an increase in capital and operating costs for the electrolyser.
- For the *natural gas supply sector*, switching from gas appliances to electric appliances results in removed production, transmission and distribution of natural gas. These removals in gas production and transport 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*, the replacement of natural gas with electricity could result in additional costs as a result of the need to change appliances. However, we assume that by 2050 any gas appliances would have to be replaced, and so switching to electricity does not incur an increase in appliance switching costs. This reflects the focus in this report on comparing annual costs in 2050, rather than costs during the transition to the scenarios that we assess.

Figure 12: Energy supply to end customers – Electrification scenario



Source: Frontier Economics

3.3 Renewable Fuels scenario – energy supply and impacts

The Renewable Fuels scenario brings about some changes to the energy supply to customers relative to the Base Case (which is discussed in Section 2.1). **Figure 13** provides a depiction of the energy supply to customers under the Renewable Fuels scenario.

There are two important changes under the Renewable Fuels scenario compared to the Base Case:

- hydrogen gas is produced, transported and injected into the natural gas distribution network and supplied directly to customers, displacing all end-use of natural gas
- electricity is supplied to the electrolyser, increasing demand for electricity.

Figure 13 also highlights the impacts – and corresponding direct supply chain costs and benefits – of the changes in energy supply arrangements in the Renewable Fuels scenario on the electricity supply sector, the gas supply sector and the hydrogen supply sector, respectively.

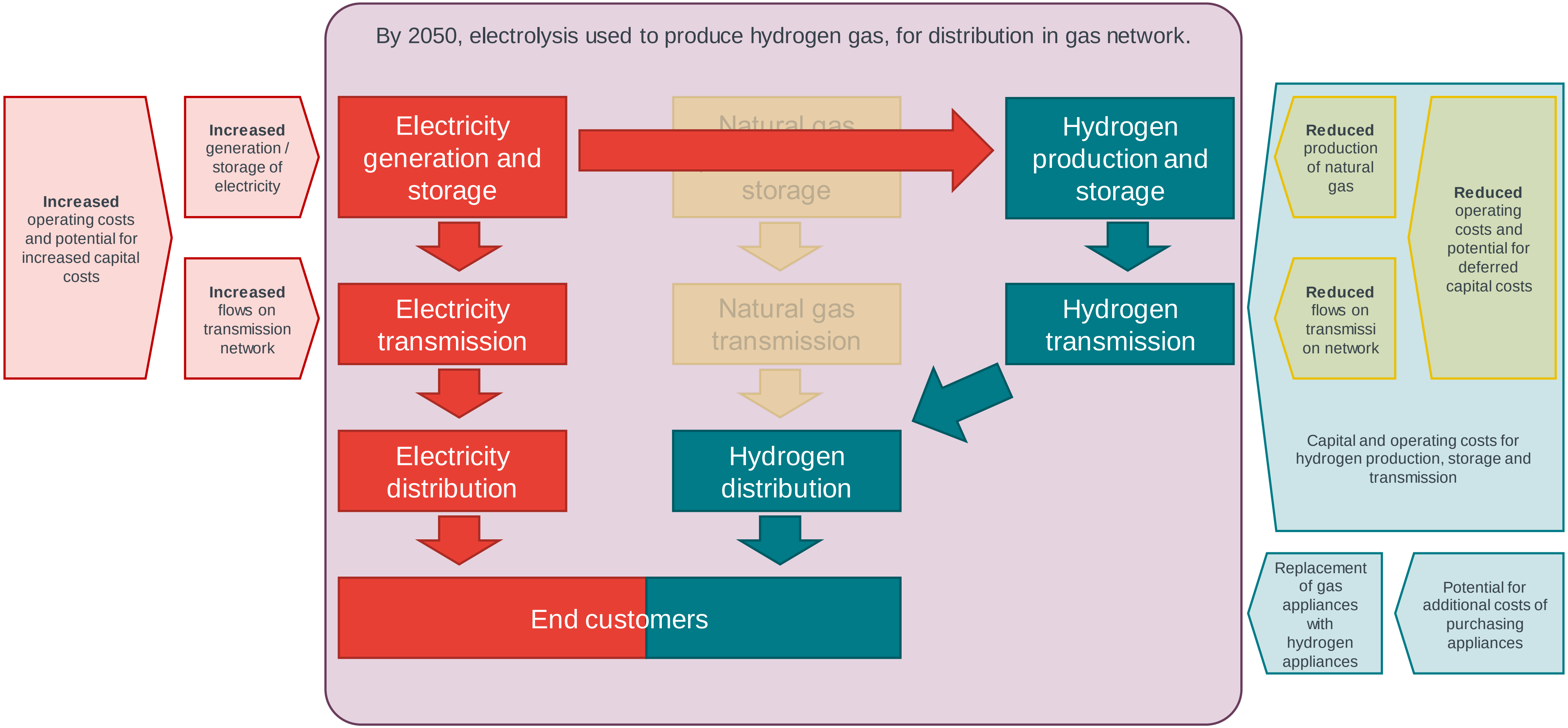
For the *electricity supply sector*, the production of hydrogen using the electrolyser leads to an increase in electricity generation. Depending on the timing of the operation of the electrolyser this could also lead to a change in the storage of electricity – it may be that the electrolyser operates at times when there is surplus electricity that would be stored in the Base Case, therefore reducing the amount of electricity storage. 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.

For the *natural gas supply sector*, the replacement of natural gas by hydrogen in 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 replacement of natural gas with hydrogen gas could result in changes to the costs of operating the distribution network due to the different physical characteristics of hydrogen gas.

For the *hydrogen supply sector*, the need to produce hydrogen for replacing end-use of natural gas requires the construction and operation of electrolysers and transmission capacity. 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. Because we assumed that electrolysers are located near electricity generation, a hydrogen transmission network is required to transport hydrogen from the electrolysers to distribution networks and commercial and industrial customers. There will be additional capital and operating costs associated with this hydrogen transmission network.

For *customers*, the replacement of natural gas with hydrogen gas could result in additional costs as a result of the need to retrofit existing appliances to burn hydrogen gas. However, we assume that by 2050 any gas appliances would have to be replaced, and so switching to hydrogen does not incur an increase in appliance costs. This reflects the focus in this report on comparing annual costs in 2050, rather than costs during the transition to the scenarios that we assess.

Figure 13: Energy supply to end customers – Renewable Fuels scenario



Source: Frontier Economics

3.4 Zero-carbon Fuels – energy supply and impacts

The Zero-carbon Fuels scenario brings about some changes to the energy supply to customers relative to the Base Case (which is discussed in Section 2.1). **Figure 14** provides a depiction of the energy supply to customers connected to a typical gas distribution network under the Zero-carbon Fuels scenario.

There are four important changes under the Zero-carbon Fuels scenario compared to the Base Case:

- hydrogen gas is produced and injected into the natural gas distribution network, replacing all of the natural gas
- natural gas is supplied to the steam methane reformer, increasing the demand for natural gas
- carbon from the steam methane reformer is captured and stored
- more natural gas flows along the gas transmission network.

Figure 14 also highlights the impacts – and corresponding direct supply chain costs and benefits – of the changes in energy supply arrangements in the Zero-carbon Fuels scenario on the electricity supply sector, the gas supply sector and the hydrogen supply sector, respectively.

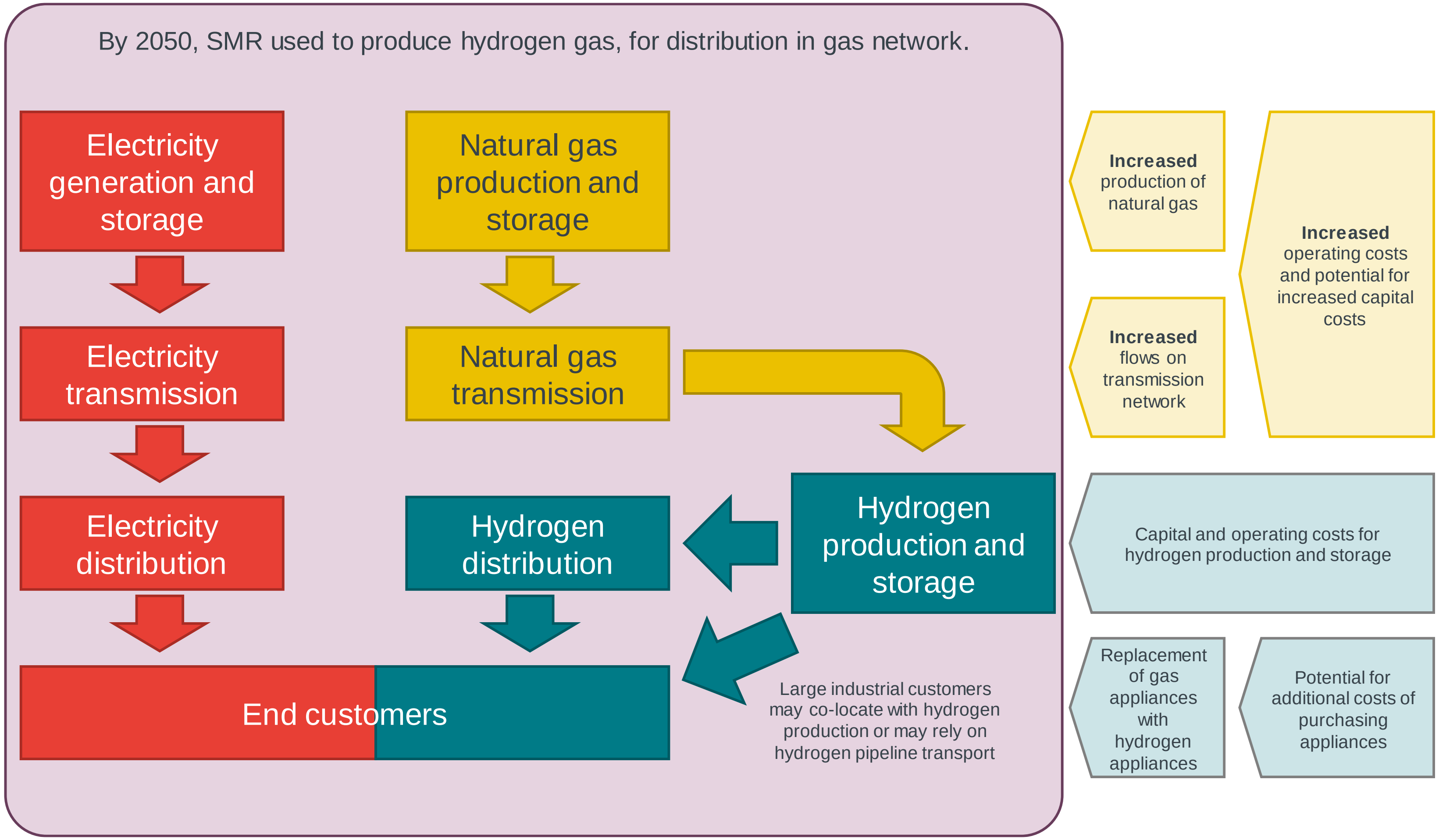
Since steam methane reforming utilises a chemical reaction with natural gas to produce hydrogen, we have assumed that there will be no material change in the *electricity supply sector*. There is likely to be some increase in electricity use as a result of the electricity requirements of the steam methane reformer and of the transport and storage or captured carbon, but neither of these is likely to be material.

For the *natural gas supply sector*, natural gas would be used as a feedstock to produce hydrogen. More natural gas is needed to produce the equivalent amount of energy as hydrogen, increasing the need for natural gas production, storage and transmission. Depending on the efficiency and how the steam methane reformer is operated, this may increase natural gas transmission costs. For the gas distribution network, the replacement of natural gas with hydrogen gas could result in changes to the costs of operating the distribution network due to the different physical characteristics of hydrogen gas.

For the *hydrogen supply sector*, the need to produce hydrogen for replacing end-use of natural gas requires the construction and operation of the steam methane reformer. There will be additional capital and operating costs associated with the steam methane reformer. 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. The assumption that carbon will be captured and storage also implies that there will be capital and operating costs of carbon capture and storage.

For *customers*, the replacement of natural gas with hydrogen gas could result in additional costs as a result of the need to retrofit existing appliances to burn hydrogen gas. However, we assume that by 2050 any gas appliances would have to be replaced, and so switching to hydrogen does not incur an increase in appliance costs. This reflects the focus in this report on comparing annual costs in 2050, rather than costs during the transition to the scenarios that we assess.

Figure 14: Energy supply to end customers – Zero-carbon Fuels scenario



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. This first step essentially consists of determining how switching away from natural gas will take place in each of the three scenarios 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, transporting and storing hydrogen. Our approach is discussed in Section 4.4.

4.1 Switching patterns – changes in natural gas, electricity, hydrogen and biogas consumption

4.1.1 Changes in natural gas consumption – all scenarios

The starting point for estimating changes in natural gas consumption, electricity consumption and hydrogen consumption is to assess the reduction in natural gas consumption. In each of our scenarios we are assuming that all end-use natural gas consumption is displaced. That means that the amount of end-use natural gas consumption that is displaced is the forecast of natural gas consumption for the Base Case, as discussed in Section 2.2.

4.1.2 Increase in hydrogen consumption – Renewable Fuels scenario and Zero-carbon Fuels scenario

The amount of end-use natural gas to be displaced implies the amount of hydrogen to be produced to displace this gas in both the Renewable Fuels scenario and the Zero-carbon Fuels scenario.

We have assumed that, measured in energy terms, the hydrogen to be produced exactly matches the natural gas to be displaced.

In reality there may be some difference between the amount of hydrogen to be produced and the amount of end-use natural gas to be displaced. One reason is that some natural gas is used as feedstock and for these purposes a given amount of natural gas may be substituted by a different quantity of hydrogen; for instance, in ammonia production (which accounts for a large amount of natural gas used as feedstock) less hydrogen than natural gas is required to produce a given amount of ammonia. Since we assume that natural gas used as feedstock is replaced by hydrogen in all three scenarios, this difference will not affect relative costs of the scenarios.

4.1.3 Changes in electricity consumption due to hydrogen production – Renewable Fuels scenario

The amount of electricity required to produce a given amount of hydrogen using electrolysis is determined by the efficiency of the electrolyser. However, we are interested not just in the amount of electricity that is required to operate the electrolyser but also the time at which the electricity is required. The reason is that operating the electrolyser at times of low-cost electricity can significantly reduce the electricity cost of producing hydrogen, but will require greater hydrogen production or storage capacity.

In fact, the cost of electricity is expected to be the largest cost component of hydrogen production. For this reason, we have assumed that the capacity of the hydrogen electrolyser and hydrogen storage will be built to take advantage of cheap electricity costs; in other words, we have assumed that the focus of hydrogen production will be on minimising electricity costs.

Determining the time at which electricity is used to produce the required amount of hydrogen in the Renewable Fuels scenario requires a co-optimisation of hydrogen production with the electricity market. We undertake this co-optimisation by allowing our electricity market model to have regard to the necessary hydrogen demand. This co-optimisation is based on assumptions about the cost of producing and storing hydrogen (in addition to our standard electricity market assumptions, as adopted in the Base Case and described in Appendix A). 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 1**.
- The assumptions on costs and technical characteristics for hydrogen storage 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 2**.

Table 1: Costs and characteristics of hydrogen production using electrolysis

	2050
Production capex (AUD/kW$_e$)	$643
Production opex (% of capex)	1.5%
Production efficiency (%, LHV)	74%
Production life (years)	24

Source: IEA, The Future of Hydrogen; Seizing today's opportunities, Report prepared by the IEA for the G20, Japan, June 2019, IRE-, Hydrogen from Renewable Power; Technology Outlook for the Energy Transition, September 2018.

Table 2: Costs and characteristics of hydrogen storage – depleted gas field

	2050
Storage capex ($/GJ)	$48.39
Storage opex ($/GJ/a)	$0.18
Storage losses (%)	0.50%
Storage life (years)	30

Source: DNV GL, Hydrogen in the Electricity Value Chain, Position Paper 2019.

There is uncertainty about the best hydrogen storage options in Australia 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 Renewable Fuels scenario we have assumed that storage in depleted gas fields is possible, and have based the costs of storage (as set out in **Table 2**) on that assumption. Under the Renewable Fuels scenario, 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 costs are at their lowest, and stored hydrogen can then be used to meet the increased demand for hydrogen during winter.

4.1.4 Changes in gas consumption due to hydrogen production – Zero-carbon Fuels scenario

The amount of gas required to produce a given amount of hydrogen using SMR is determined by the efficiency of the SMR. As with the electricity used by the electrolyser, when it comes to the gas used by the SMR, we are interested in the timing of gas use and hydrogen production. In this case, the key issue is not the ability to produce at times of low gas cost – gas costs are neither as volatile nor as seasonal as electricity prices, indicating that there is less ability to save on gas costs – but the required mix of SMR and storage capacity.

To determine the require SMR capacity we assume that the intention will be to minimise the capacity of the SMR in order to minimise the associated capital costs. We determine this by calculating the amount of SMR capacity required to meet annual demand for hydrogen – assuming that the SMR operates consistently throughout the year – and then determining the amount of storage that is required to meet seasonal demand with this constant production rate. The costs and technical characteristics for hydrogen production using SMR are set out in **Table 3** and the assumptions on costs and technical characteristics for hydrogen storage are the same as used for the Renewable Fuels scenario (as set out in **Table 2**).

Table 3: Costs and characteristics of hydrogen production using SMR with CCS

	2050
Production capex (AUD/kW_{H2})	$1,829
Production opex (% of capex)	3.0%
Production efficiency (%, LHV)	69%
Production life (years)	24

Source: IEA, The Future of Hydrogen; Seizing today's opportunities, Report prepared by the IEA for the G20, Japan, June 2019, IRE-, Hydrogen from Renewable Power; Technology Outlook for the Energy Transition, September 2018.

4.1.5 Changes in electricity consumption due to electricity switching – Electrification scenario

Calculating the amount of electricity required to replace natural gas in the Electricity Switching Case is somewhat complex. There are several reasons for this. First. the options that are available to switch to electricity will vary by customer. Second, for some appliances or uses there are differences in efficiency, which needs to be accounted for in determining electricity consumption. We address each of these below.

Options for switching to electricity

We consider options for switching from gas to electricity for each category of customers.

For **residential and commercial** customers, we assume that all gas consumption can be switched to electricity consumption. We assume that a mix of electric cooking, electric water heating and electric heat pumps for space heating will meet the energy requirements for these customers that are forecast to be met by gas in 2050 in the Base Case.

For **gas-fired generators**, we assume that fuel switching will occur by 2050 through the replacement of gas-fired generation with other forms of generation in our electricity market modelling. Based on the assumptions that we use in our electricity market modelling – discussed in Appendix A – we find that almost all gas-fired generation will be replaced by cheaper renewable generation and storage in the Base Case. We assume that the emissions associated with the very small amount of gas used by the small amount of gas peaking capacity that remains can be offset (or renewable gas used).

For **industrial** customers, we consider options for switching from gas to electricity by sector. This is due to the quite different energy requirements of different sectors.

Estimates of gas use by industrial sector, as well as the heat requirements for each sector, are provided in **Figure 15**, from an IT Power report for the Australian Renewable Energy Agency (ARENA).[1] By calculating the proportion of gas use in each industrial sector that falls within each of the defined temperature bands, we can combine these estimates with the forecasts of end-use gas consumption for each industrial sector in 2050 in the Base Case (which forecasts, as discussed in Section 2.2, are based on more recent data on industrial gas use). The result is a forecast of the heat requirement for the gas to be displaced in each industrial sector in 2050.

[1] IT Power, *Renewable Energy Options for Australian Industrial Gas Users*, Prepared for the Australian Renewable Energy Agency, September 2015.

Figure 15: Gas requirements by industrial sector

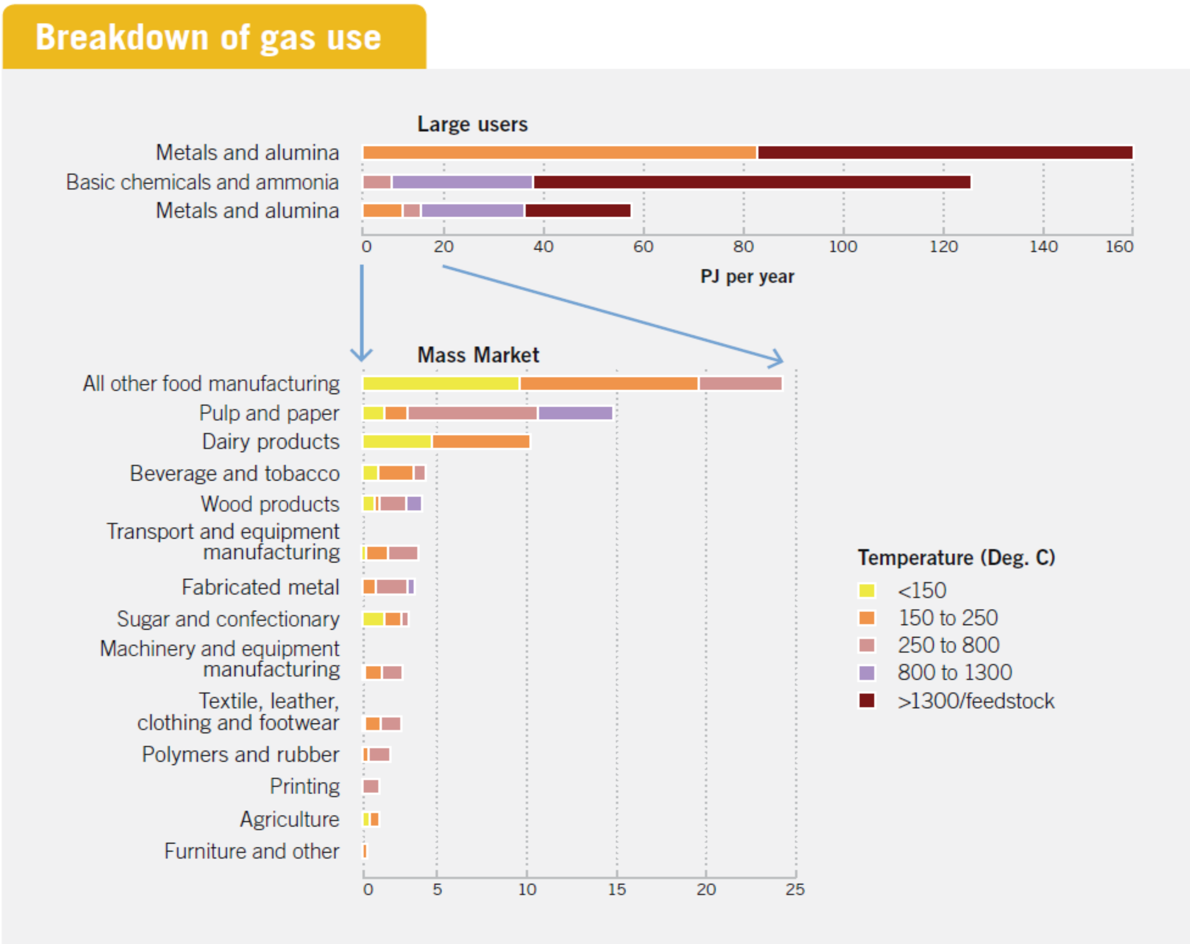


Figure 4. Sector breakdowns for the various industrial gas uses for the year 2012-13. The total is 412PJ per year[7].

Source: IT Power, Renewable Energy Options for Australian Industrial Gas Users, Prepared for the Australian Renewable Energy Agency, September 2015.

Note: The metals and alumina sector appears in the figure twice. Based on total consumption, we expect that the second entry for the metals and alumina sector is, in fact, the non-metallic minerals sector.

These estimates can then be combined with assumptions about the alternative energy sources that are available to meet these temperature requirements in each industrial sector. We have reviewed a number of reports on the alternatives to gas use by industrial customers, including this same report by IT Power for ARENA[2] and a more recent IT Power for ARENA on renewable energy options for industrial heat.[3] Based on this review, and by applying judgement, we have assessed the alternatives to gas use for the heat requirements in each industrial sector as summarised in **Table 4**. We make the following general comments about these assessments:

- We have assumed that electric heat pumps will be used in place of natural gas for low temperature heat requirements.

[2] IT Power, *Renewable Energy Options for Australian Industrial Gas Users*, Prepared for the Australian Renewable Energy Agency, September 2015.

[3] IT Power, *Renewable Energy Options for Industrial Process Heat*, Prepared for the Australian Renewable Energy Agency, November 2019.

- We have assumed that other electrical technologies – including electrical resistance heating, electric arc furnaces and induction furnaces – are generally used for higher temperature heat requirements up to 1300 degrees.
- We have assumed that for heat requirements above 1300 degrees, or where natural gas is used as a feedstock, hydrogen will be used in place of natural gas.
- We have assumed that where it appears to be a reasonable option, and where the industry is generally located in regional or rural areas, solar thermal can be used for a range of heat requirements.

Additionally, we assume that gas used in mining and in oil and gas extraction is used in remote areas that will be best served by on-site renewable generation and storage.

The resulting alternative energy requirements for industrial gas users are set out in **Table 5**.

Of these alternative energy sources, it is only the electricity required for use of heat pumps and various other forms of electric heating that are supplied directly through the existing electricity network. Additionally, we have assumed that hydrogen will be produced by ‘on-site’ electrolysers, which will also require electricity supplied through the existing electricity network.

The industrial heat uses which are supplied by solar thermal technology require that the industrial facility is co-located with the solar thermal plant. And replacement of natural gas used in mining and in oil and gas extraction also requires that the facilities are co-located with renewable storage and generation.

Table 4: Assumed alternative to industrial gas end-use

	<150	150 TO 250	250 TO 800	800 TO 1300	>1300	FEEDSTOCK
1701 Petroleum refining	-	Electrical resistance	Hydrogen	Hydrogen	Hydrogen	-
1709 Other petroleum and coal product manufacturing	-	Electrical resistance	Hydrogen	Hydrogen	Hydrogen	-
211-212 Iron and steel	-	Electric arc furnace	-	-	-	Hydrogen
213-214 Basic non-ferrous metals	-	Solar thermal	-	-	Hydrogen	-
11-12 Food, beverages and tobacco	Heat pump	Electrical resistance	Electrical resistance	-	-	-
13 Textile, clothing, footwear and leather	-	Electrical resistance	Electrical resistance	-	-	-
14 Wood and wood products	Heat pump	Electrical resistance	Electrical resistance	Electrical resistance	-	-
15-16 Pulp, paper and printing	Heat pump	Solar thermal	Solar thermal	Solar thermal	-	-
18-19 Basic Chemical and Chemical, Polymer and Rubber Product Manufacturing	-	Electrical resistance	Solar thermal	Solar thermal	-	Hydrogen
20 Non-metallic mineral products	-	Electrical resistance	Electrical resistance	Electrical resistance	Hydrogen	-
22 Fabricated metal products	-	Induction furnace	Induction furnace	Induction furnace	-	-
23-24 Machinery and equipment	-	Induction furnace	Induction furnace	-	-	-
25 Furniture and other manufacturing	-	Electrical resistance	-	-	-	-

		<150	150 TO 250	250 TO 800	800 TO 1300	>1300	FEEDSTOCK
Div. A	Agriculture, forestry and fishing	Heat pump	Solar thermal	-	-	-	-
Div. E	Construction	Heat pump	Electrical resistance	-	-	-	-
Div. I	Transport, postal & warehousing	Heat pump	Electrical resistance	Electrical resistance	-	-	-

Source: Frontier Economics

Table 5: Alternative energy requirements for industrial gas end-use, 2050

ALTERNATIVE TO INDUSTRIAL GAS END-USE	UNITS	NSW	QLD	SA	TAS	VIC	WA
Grid-sourced electricity							
Heat pump	PJ of electricity required	0.99	0.60	0.39	0.15	2.61	0.66
Electrical resistance	PJ of electricity required	11.67	7.93	8.55	0.64	19.25	13.13
Induction furnace	PJ of electricity required	0.00	0.00	0.35	0.00	0.90	0.00
Electric arc furnace	PJ of electricity required	1.11	1.76	0.17	0.08	0.72	4.16
Hydrogen (accounting for electrolyser efficiency)	PJ of electricity required	40.83	57.21	11.90	2.56	28.07	135.07
Distributed generation							
Solar thermal - parabolic trough w/ 6 hours storage	PJ of solar thermal energy required	7.82	12.56	1.25	0.58	7.49	29.12
Solar thermal - central receiver w/ 6 hours storage	PJ of solar thermal energy required	2.64	4.28	0.41	0.20	2.46	9.95
Renewable and storage for mine sites	PJ of renewable required	0.11	49.04	6.54	0.00	9.94	84.64

Source: Frontier Economics

Relative appliance efficiency

The second difficultly with identifying the electricity required to replace gas is accounting for any differences in relative efficiency between gas appliances and the appliances that would be used as an alternative in the Electrification scenario. This difference in relative efficiency 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 replaced from annual consumption 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 to be replaced from annual consumption 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,[4] 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,[5] to calculate the amount of electricity required to produce this same amount of heat energy.[6] 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 replace the daily gas consumption.

We also account for the efficiency of gas boilers, steam systems and furnaces when accounting for the heat requirements to be delivered by solar thermal systems.

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 Electrification scenario and the Renewable Fuels scenario, but an increase in production in the Zero-carbon Fuels scenario. 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. The increase in gas production under the Zero-carbon Fuels scenario is driven by the efficiency of the steam methane reformer, which requires more natural gas to produce the equivalent amount of hydrogen in terms of energy.

[4] Alinta Energy website: https://www.alintaenergy.com.au/wa/blog/heating/the-most-efficient-gas-heaters-on-the-market

[5] Department of the Environment and Energy website: https://www.environment.gov.au/system/files/energy/files/hvac-factsheet-heat-pump-tech.pdf

[6] We note that there are other estimates which suggest the coefficient of performance for heat pumps is higher than 2.5. Given that a relatively small amount of end-use gas consumption is replaced by heat pumps, varying this assumption is unlikely to change the relative results between our scenarios.

We calculate changes in the costs of gas production by multiplying the change in annual gas production 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 each scenario, as discussed in Section 4.1.

The levelised 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 2019 Gas Statement of Opportunities (GSOO).[7] 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 in 2050 will come from undeveloped 2P or 2C reserves, and not from existing supplies. 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. Note that this is the levelised cost of gas commodity only, it does not include costs of delivery through the gas transmission network.

Changes in gas transmission costs

As discussed in Section 3, there is a decrease in gas transmission in both the Renewable Fuels scenario and the Electrification scenario, while there is an increase in gas transmission in the Zero-carbon Fuels scenario. A decrease in gas transmission is likely to result in deferred pipeline investment and therefore a reduction in capital costs in the Renewable Fuels scenario and the Electrification scenario relative to the Base Case; because investment in pipeline capacity is likely to be required before 2050, a reduction in demand is likely to enable some part of this investment in new capacity to be deferred. This will not be the case for the Zero-carbon Fuels scenario, which will likely require an investment to service the increased natural gas demand. 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.

We calculate changes in the costs of gas transmission by multiplying the change in annual gas transmission 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 each scenario, as discussed in Section 4.1.

As a proxy for the levelised 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 interested in changes in use of the network of pipelines – and much gas currently flows through more than one pipeline – we do not use an estimate of a typical single pipeline, but use a higher estimate to reflect the use of multiple pipelines.

We assume that a typical molecule of gas would flow through pipelines with a combined cost of $2.50/GJ/day of Maximum Daily Quantity (MDQ).[8]

[7] AEMO, 2019 Gas Statement of Opportunities supply input data files. Available at: https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo/2019-gas-statement-of-opportunities

[8] Firm pipeline tariffs are typically based on the pipeline capacity reserved by the gas shipper, with that pipeline capacity typically expressed in units of GJ/day of MDQ.

Changes in gas distribution costs

As discussed in Section 3, gas distribution costs may change in the scenarios for different reasons.

In the Renewable Fuels scenario and the Zero-carbon Fuels scenario there is an increase in the total volume of hydrogen as compared to natural 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 hydrogen without material modification or additional cost.

In the Electrification scenario there is an elimination of gas flows on the gas distribution network. However, since most gas distribution network are forecasting reductions in gas demand in the Base Case, we assume that there will be no new investment in the gas distribution network in the Base Case in 2050. As a result, the elimination of gas flows in the Electrification scenario does not give rise to any avoided costs.

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 Renewable Fuels scenario and the Electrification scenario, although the magnitude and timing of the increase is different between the two cases. Since steam methane reforming does not use a material amount of electricity, the Zero-carbon Fuels scenario does not see an increase in transmission costs.

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 model – *WHIRLYGIG* – as described in Section 2.3. Changes in costs relative to the Base Case are determined by modelling *WHIRLYGIG* for each scenario with the relevant change in grid-sourced electricity for that scenario.[9]

For the distributed generation used by industrial customers we still model the costs of generation and storage for electricity and heat using the same approach, but we treat this demand for electricity and heat as needing to be met by a stand-alone system, rather than being met by supply from the grid.

Changes in transmission costs

As discussed in Section 3, there is an increase in electricity transmission in the Electrification scenario. Since electrolysers are sited at points of generation, and new hydrogen transmission infrastructure is

[9] Because we are interested in the costs and benefits of the Renewable Fuels scenario and the Electrification scenario 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 (PPA). 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.

used to transport hydrogen to distribution networks, the Renewable Fuels scenario does not see an increase in electricity transmission costs. Since steam methane reforming with natural gas does not use a material amount of electricity, the Zero-carbon Fuels scenario does not see an increase in transmission costs.

An increase in electricity transmission is likely to result in additional investment in transmission capacity and therefore an increase in capital costs in the Electrification scenario relative to the Base Case; because investment in transmission capacity is likely to be required, an increase in demand is likely to drive the need for additional capacity. 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.

For the Electrification scenario the change in peak demand for the electricity *transmission* network is the same as the change in peak demand for the electricity *distribution* network. The reason is that we are assuming that all additional demand for grid-sourced electricity is from customers 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 electricity *distribution* network in the section below.

Ideally, the benchmark cost that we would use for electricity transmission network would be an estimate of the long run marginal cost (LRMC) for the transmission network in 2050. However, an estimate of the LRMC for the transmission network in 2050 is not readily available. Even estimates of the *current* LRMC of the transmission network would not necessarily be a useful guide to the LRMC of the transmission network in 2050. The reason is that the way that LRMC of electricity networks is typically estimated – using an average incremental cost (AIC) approach – results in the estimated LRMC being influenced by the amount of spare capacity on the network. At times in which there is spare capacity on the network the estimated AIC is likely to be lower than it is at times in which there is not spare capacity on the network. Given the reduction in demand that has occurred over the last decade (driven in large part by the installation of rooftop solar PV) many electricity networks in Australia currently have spare capacity, which would result in relatively low estimates of LRMC.

Given this, we estimate the cost of the electricity transmission network based on the current annual allowed revenues for each transmission network, divided by the annual peak demand for the network. This provides an estimate of annual allowed revenues per unit of peak demand, as shown in **Table 6**. The data that we use to calculate this is data on annual allowed revenues and peak demand released by the Australian Energy Regulator (AER).

This estimate of the annual allowed revenues per unit of peak demand, expressed in real terms, can provide an indication of costs additional demand on the network in 2050. Of course this is only an estimate, and the estimated annual allowed revenues per unit of peak demand may be higher or lower than the true LRMC of the network in 2050.

Table 6: Annual allowed revenues per unit of peak demand, by region – transmission networks

	MAXIMUM DEMAND IN 2018 (MW)	ALLOWED REVENUES IN 2018 ($ 2019)	AVERAGE COST ($/KVA, $ 2019)
NSW	18,500.00	$732,744,963	$36
QLD	11,967.86	$800,601,801	$60
SA	3,239.96	$359,595,444	$100
SWIS	3,859.00	$341,453,125	$80
TAS	2,469.60	$184,087,052	$67
VIC	10,005.42	$604,797,508	$54

Source: AER

Note: A power factor of 0.9 is assumed.

Changes in distribution costs

As discussed in Section 3, there is an increase in electricity distribution only in the Electrification scenario, 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 Electrification scenario 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.

As with our estimates of the change in transmission costs, we do not use current estimates of the LRMC of the network to estimate the costs of additional peak demand in 2050. The reasons are the same: the current estimates of LRMC – based on an AIC approach – will result in lower estimates of LRMC where there is spare capacity on the network, as there is for many electricity networks in Australia.

Instead, we estimate the cost of the electricity distribution network based on the current annual allowed revenues for distribution networks in each region, divided by the annual peak demand. This provides an estimate of annual allowed revenues per unit of peak demand, as shown in **Table 7**. The data that we use to calculate this is data on annual allowed revenues and peak demand released by the Australian Energy Regulator (AER).

This estimate of the annual allowed revenues per unit of peak demand, expressed in real terms, can provide an indication of costs additional demand on the distribution network in 2050. Of course this is only an estimate, and the estimated annual allowed revenues per unit of peak demand may be higher or lower than the true LRMC of the network in 2050. We note that these estimate of the annual allowed revenues per unit of peak demand are higher than the current LRMCs typically reported by distribution networks; although, as we note above, we expect that this is due, at least in part, to spare capacity on most distribution networks.

Table 7: Annual allowed revenues per unit of peak demand, by region – distribution networks

	MAXIMUM DEMAND IN 2018 (MW)	ALLOWED REVENUES IN 2018 ($ 2019)	AVERAGE COST ($/KVA, $ 2019)
NSW	13,065.78	$3,553,784,194	$245
QLD	8,659.58	$2,922,610,525	$304
SA	2,869.49	$808,857,726	$254
SWIS	3,859.00	$1,421,285,500	$331
TAS	259.46	$249,521,189	$866
VIC	9,078.95	$2,242,987,287	$222

Source: AER

Note: A power factor of 0.9 is assumed

4.4 Changes in costs of producing, transporting and storing hydrogen

As discussed in Section 3, hydrogen production and storage is required in the Renewable Fuels scenario and the Zero-carbon Fuels scenario. As well as the increase in the cost of generating and transporting electricity or gas that these options require (and which are accounted for elsewhere our cost estimates) there are also capital and operating costs associated with this hydrogen production and storage.

We discuss our approach to determining required hydrogen production and storage capacity in Sections 4.1.3 and 4.1.4. We use the estimates of capital and operating costs of hydrogen production and storage that are set out in **Table 1**, **Table 2** and **Table 3** to determine the total capital and operating costs of this capacity.

We assume that the operating costs set out in **Table 1** 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. From experience, we assume that this cost is captured within the operating cost of the electrolyser.

Hydrogen transmission is required in the Renewable Fuels scenario to transport hydrogen produced near generation between regions, to distribution networks and to commercial and industrial customers. We have estimated the length of this transmission network and multiplied it by an annual cost per kilometre based on cost estimates outlined in **Table 8**. To estimate the length of the transmission network, we developed a hypothetical hydrogen transmission network connecting renewable energy generation sites (e.g. AEMO’s Renewable Energy Zones) to a wider transmission network between regions. The length of our hypothetical transmission network is around 9% longer than the current onshore Australian gas transmission network.

Table 8: Costs and characteristics of hydrogen transmission

	2050
Pipeline length (km)	18,508
Pipeline cost ($m/km)	$1.73
Production opex (% of capex)	1.5%
Life (years)	40

Source: Pipeline cost, approximate capacity and life assumptions from IEA, The Future of Hydrogen; Seizing today's opportunities, Report prepared by the IEA for the G20, Japan, June 2019, IRE-, Hydrogen from Renewable Power; Technology Outlook for the Energy Transition, September 2018.

4.5 Carbon capture and storage

For the Zero-carbon Fuels scenario we assume that the carbon that is produced as a result of steam methane reforming with natural gas is captured and stored. There are additional costs of carbon capture and storage.

The additional costs of capturing the carbon are accounted for in the higher capital and operating costs of the steam methane reformer with carbon capture, as discussed in Section 4.4 (based on the costs set out in **Table 3**).

The additional costs of carbon transport and storage are based on estimates from the CarbonNet Project, with estimates from that project that that the total cost to compress and transport carbon from industries in the Latrobe Valley to offshore storage sites in Bass Strait is between $30 to $50 per tonne of carbon. We have assumed an average cost of $40 per tonne.

We have assumed that all carbon produced by the steam methane reformer can be captured and stored, or otherwise offset, at this cost.

5 RESULTS

This section presents the results of our modelling. It is divided in two parts: the first part presents the results of our cost modelling for the electricity, gas, hydrogen and industrial sectors. The second part presents our cost-benefit assessment of fuel-switching options, which is informed by the results of our sector-based modelling.

5.1 Sector modelling

5.1.1 Electricity generation

As discussed in Section 4.3, our electricity modelling estimates changes in investment in and operation of generation and storage plant in each scenario under consideration. We have undertaken three *WHIRLYGIG* modelling runs for the four scenarios, including one run for the Base Case and the Zero-carbon Fuels scenario, where electricity sector costs are the same by assumption, and one run each for the Renewable Fuels scenario and the Electrification scenario.

The key difference in inputs between these runs is in the demand for electricity, as discussed in Section 4.1. In the Base Case and Zero-carbon Fuels scenario, electricity demand levels are at forecast business-as-usual levels. In the Electrification scenario, additional electricity demand is included to represent the switching of residential and commercial gas consumption, as well as those industrial heating processes that we assume can switch to grid-sourced electricity, and mine sites which we assume use distributed generation and storage. In the Renewable Fuels scenario, additional electricity demand is included to enable hydrogen production via electrolysis which is sufficient to supply all customers in the residential, commercial and industrial sectors.

In interpreting the electricity sector modelling results, it is important to note the demand inputs cover different categories of consumption and are not directly comparable for this reason. Specifically:

- The Base Case and Zero-carbon Fuels scenario includes electricity demand with no additional switching or hydrogen-related increases in demand – the costs of existing gas and hydrogen consumption are not included in the electricity sector modelling.
- The Electrification scenario includes electricity demand to represent switching from residential, commercial, and some industrial activity, and mine sites which we assume use renewable generation and storage. However, some industrial energy needs are meet from other sources, including distributed generation and hydrogen.
- The Renewable Fuels scenario includes electricity demand to represent the production of hydrogen to satisfy the needs of residential, commercial and all industrial activity. As this consumption represents all consumption sectors, and the conversion of electricity to hydrogen is not perfectly efficient, the demand from grid-sourced electricity in the Renewable Fuels scenario is the highest of the cases modelled.

Figure 16 presents the generation capacity results from *WHIRLYGIG* by state (vertical facets) and scenario (x axis). This is the generation capacity that *WHIRLYGIG* determines to be the least cost mix of generation capacity to meet demand (subject to an emissions target of net zero emissions) in 2050. The y axis represents MW of total installed capacity in the system, and the colours represent the fuel type or technology. Positive values represent generation capacity, and negative values represent storage capacity. Note that other than existing hydro generation, we assume that all other currently existing generation will retire by 2050. **Figure 16** also shows the current generation mix in 2020 for reference.

The difference in generation capacity in 2020 and forecast generation capacity in 2050 under each of the scenarios we assess is, in most states, stark. Current generation capacity is generally dominated by black/brown coal and gas, with small amounts of renewables and storage. The forecast generation capacity in 2050 for each scenario is dominated by renewables (solar and wind) and storage, and there is substantially greater installed capacity.

Part of the difference between generation capacity in 2020 and forecast generation capacity in 2050 under each of the scenarios is driven by forecast changes to generation capacity between 2020 and 2050 in the Base Case. These changes are illustrated by comparing the generation capacity in 2020 and the generation capacity in the Zero-carbon Fuels scenario in **Figure 16** – the reason is that electricity demand in the Zero-carbon Fuels scenario is the same as it is in the Base Case. It is clear from **Figure 16** that even in the Base Case and the Zero-carbon Fuels scenario there is a significant shift to renewable generation capacity and a significant increase in total installed capacity by 2050. This is driven by two key trends that are forecast to occur over the period to 2050:

- There is some growth forecast in the Base Case for both annual electricity consumption and peak electricity demand between 2020 and 2050. This requires additional generation capacity.
- There is a shift from a generation mix dominated by black/brown coal and gas to one dominated by renewables and storage. This, in turn, is a result of two factors:
    - Our 2050 modelling includes emissions target of net zero emissions. This restricts the opportunity for generation from black/brown coal and gas in 2050.
    - Our 2050 modelling is based on forecasts of falling capital costs for most forms of renewable generation and storage over time, making them lower cost than low-emissions thermal options, such as gas and coal with carbon capture and storage.

Importantly, this shift in the generation mix has important implications for the total amount of installed capacity that is required. Since wind and solar generation are intermittent, and have relatively low capacity factors, substantially more wind and solar capacity is required to meet annual consumption and peak demand than would be required with continued reliance on dispatchable coal and gas generation. In particular, there needs to be sufficient renewable generation and storage to ensure electricity demand can be met during periods of solar and wind drought, which can persist for several days. This is particularly an issue in Western Australia, where the lack of interconnection with other states means that the available generation capacity tends to experience less diversity in weather conditions than is the case in the NEM. It is for this reason that the difference in installed capacity between 2020 and the Base Case in 2050 is greatest for Western Australia.

The difference in outcomes in 2050 between the Base Case and the Zero-carbon Fuels scenario, on one hand, and the other two scenarios, is driven by very large differences in the total amount of electricity demand in 2050 and the timing of this electricity demand.

In the Electrification scenario, electricity demand increases either directly, through customers switching from end-use of gas to electricity, or indirectly, through the electricity required to produce hydrogen for those customers that switch from end-use of gas to hydrogen.

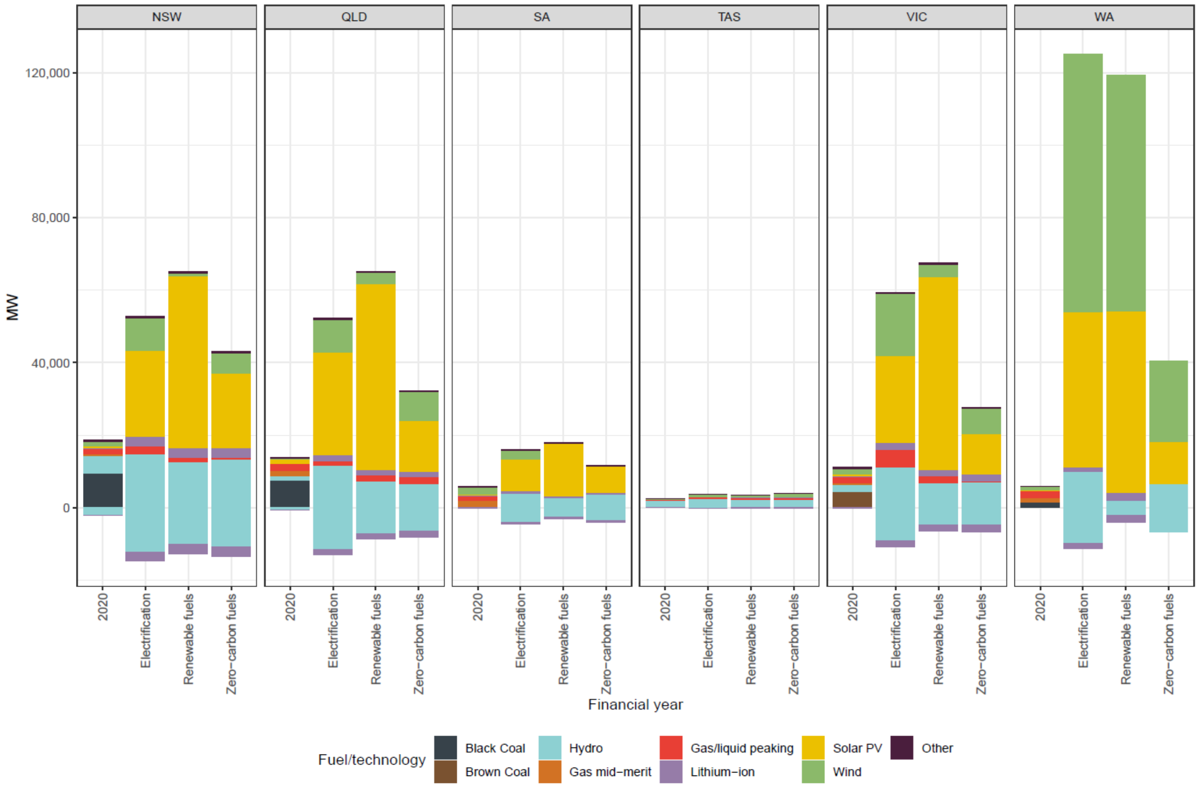
In the Renewable Fuels scenario, electricity demand increases as a result of the electricity required to produce hydrogen, as all gas end-users switch from gas to hydrogen. The total increase in annual electricity demand is higher in the Renewable Fuels scenario than in the Electrification scenario for two reasons:

- In the Renewable Fuels scenario all gas end-users switch from gas to hydrogen, which is produced using grid-sourced electricity. In the Electrification scenario, however, some gas end-users switch to alternatives that do not rely on grid-sourced electricity, such as using solar thermal for heat.
- Because of the inefficiency of electrolysers, the production of hydrogen through electrolysis requires more energy input as electricity than energy is output as hydrogen. This results in higher electricity demand.

This difference is reflected in the fact that forecast generation capacity in 2050 seen in **Figure 16** is higher in the Renewable Fuels scenario than the Electrification scenario. However, the difference is not as great as would be implied by the differences in annual electricity demand discussed above. The reason is that the demand for electricity is peakier in the Electrification scenario than in the Renewable Fuels scenario, because the storage of hydrogen in the Renewable Fuels scenario smooths out the annual demand for electricity to a greater extent than is possible in the Electrification scenario. This peakier demand in the Electrification scenario increases the need for generation capacity.

It is also clear from **Figure 16** that the differences in outcomes in 2050 between the Base Case and the Zero-carbon Fuels scenario, on one hand, and the other two scenarios, vary markedly between states. In Tasmania, for instance, the three scenarios are relatively comparable. In Western Australia, however, the installed capacity in the Renewable Fuels scenario and the Electrification scenario is much greater than the installed capacity in the Base Case and the Zero-carbon Fuels scenario. This difference between states is driven by the amount of gas consumption in the state: Tasmania uses relatively little gas compared to its electricity consumption, so installed generation capacity is relatively similar even where gas end-users switch to electricity and/or hydrogen; Western Australia, however, uses significantly more gas than electricity, which means that the installed generation capacity is much higher where gas end-users switch to electricity and/or hydrogen.

Figure 16: Total installed capacity by state, all scenarios



Source: Frontier Economics' modelling

5.1.2 Electricity network

As discussed in Section 4.3, our electricity network sector modelling estimates the costs of augmenting the electricity transmission and distribution networks arising from electricity demand in scenarios above Base Case levels. The Electrification scenario and the Renewable Fuels scenarios have increased electricity demand over the Base Case, reflecting additional requirements from the system in switching to the respective alternative fuels. The Zero-carbon Fuels scenario sees no increase in electricity demand over the Base Case as the demand from the electricity is, by assumption, unchanged.

Figure 17 presents the results of our electricity network cost modelling. **Figure 17** shows differences in annual costs in 2050; positive values reflect an increase in costs compared to the Base Case, negative values reflect a reduction in costs.

In the Electrification scenario, demand on both the transmission and distribution networks is increased as gas consumption by residential, commercial and some industrial customers is replaced with electricity consumption, leading to increases in costs. While both the transmission and distribution networks see similar increases in demand, the cost of augmenting the distribution network are substantially higher than the cost of augmenting the transmission network, and so form the bulk of the network-related costs. Differences in costs by state reflect different levels of underlying gas consumption and appliance mixes in each region, and difference estimates in the cost of electricity networks (as discussed in Section 4.3).

In the Renewable Fuels scenario, demands on the electricity transmission network are unchanged. By assumption, the electricity required for the production of hydrogen (e.g. in AEMO's Renewable Energy Zones) and hydrogen production facilities are co-located. Hydrogen produced at these sites is transported via a hydrogen transmission network to city gates, connecting to existing gas distribution networks, or to large consumers.

There is also no required augmentation of the distribution network in this scenario because there is no increase in electricity network flows past the city gate – all the additional electricity is converted into hydrogen.

Figure 17: Electricity network, difference in annual costs in 2050 from Base Case ($2020)

Source: Frontier Economics' analysis

5.1.3 Gas production

As discussed in Section 4.2, our gas production modelling estimates the changes in costs of gas consumption between scenarios and the Base Case.

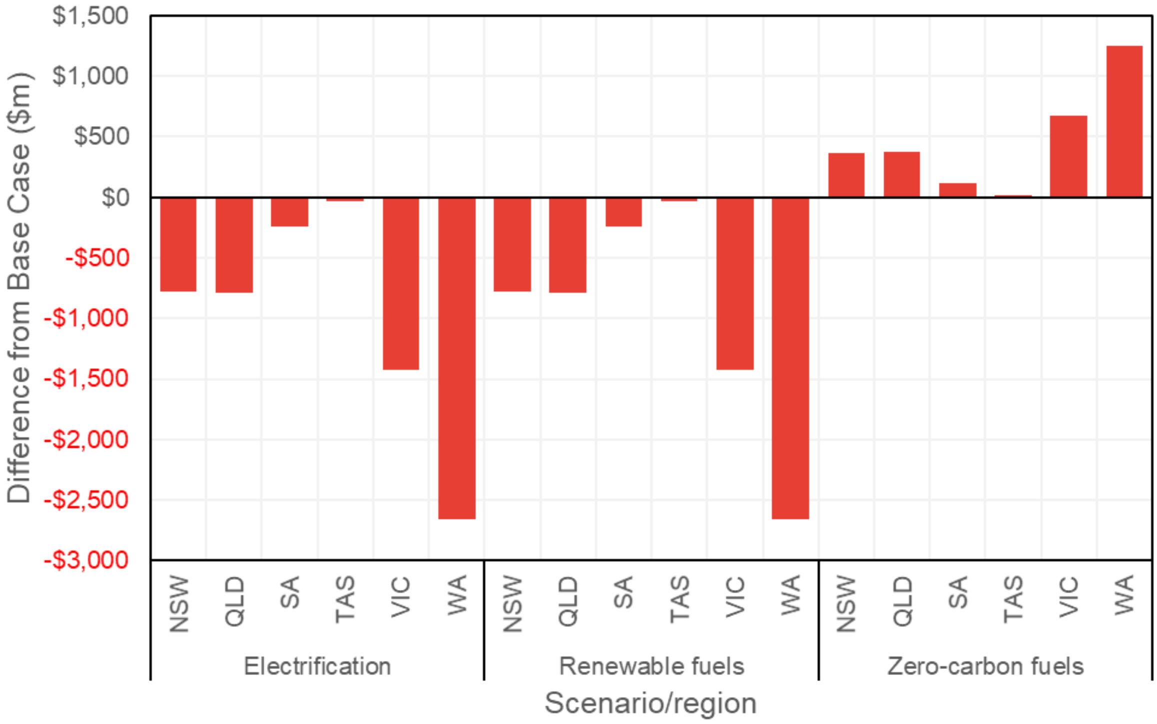
Figure 18 presents a summary of our gas production cost modelling by scenario and region. **Figure 18** shows differences in annual costs in 2050; positive values reflect an increase in costs on the Base Case, negative values reflect a reduction in costs.

By assumption, gas production for domestic consumption in the Electrification scenario and the Renewable Fuels scenarios is stopped by 2050 as energy consumption from natural gas is switched to the respective alternatives. The differences in cost between the Partial Electrification and Renewable Fuels scenarios and the Base Case reflect the cost of avoiding the entirety of Base Case gas production costs in 2050.

The increasing costs above the Base Case in the Zero-carbon Fuels scenario reflect the incremental costs required to produce the energy-equivalent quantity of natural gas consumption in hydrogen. As the process of converting natural gas to hydrogen through steam methane reforming is not 100% efficient, the amount of gas consumption in the Zero-carbon Fuels scenario is more than in the Base Case and hence more expensive.

In all scenarios Western Australia has the highest cost differentials due to its heavy reliance on natural gas as an input fuel.

Figure 18: Gas production costs, difference in annual cost in 2050 from Base Case ($2020)



Source: Frontier Economics' analysis

5.1.4 Gas network

As discussed in Section 4.2, our gas network modelling estimates the differences in costs required for augmentations of the gas transmission and distribution networks in each of the scenarios relative to the Base Case. Differences in costs relating to the gas network may arise from increases in demand for gas transmission or distribution services.

Figure 19 presents a summary of our gas production cost modelling by scenario and region. **Figure 19** shows differences in annual costs in 2050; positive values reflect an increase in costs on the Base Case, negative values reflect a reduction in costs.

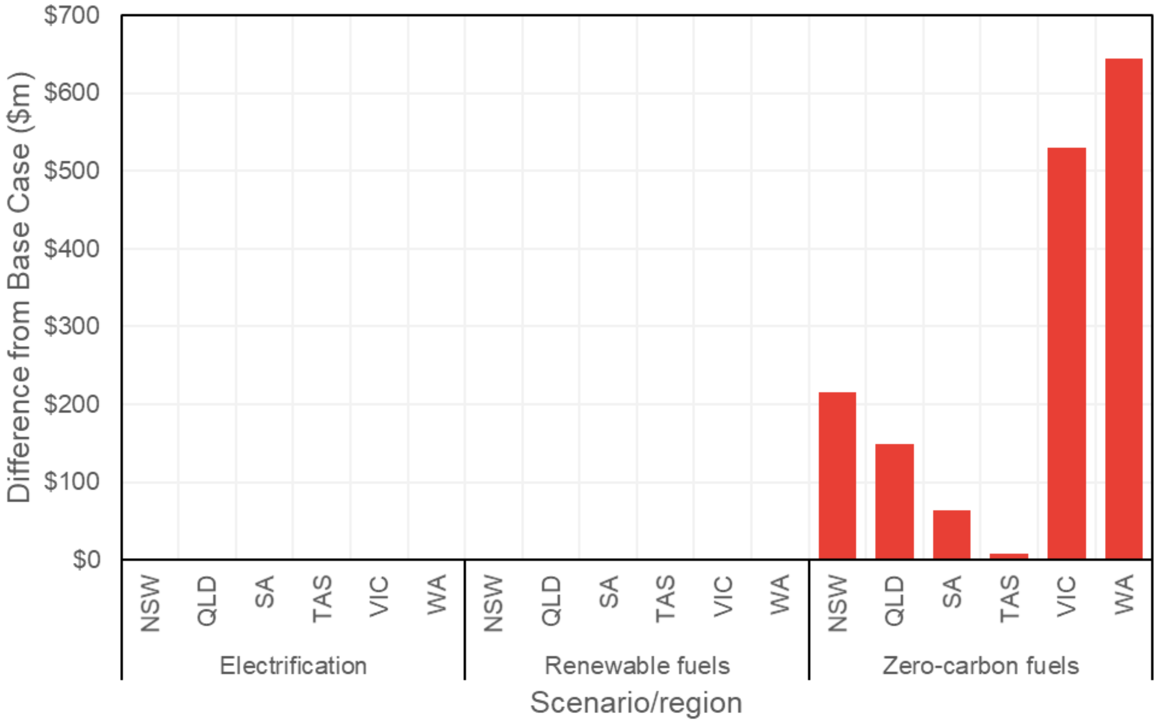
In the Electrification scenario, neither natural gas nor hydrogen are consumed from the gas network (although some local hydrogen is produced), meaning no augmentation of either the distribution or transmission gas network is required.

Similarly, the Renewable Fuels scenario sees the hydrogen transmission network transporting energy long distances, meaning no augmentation is required of the gas transmission network. At the distribution level, the same energy content in hydrogen is being transported in place of natural gas in the distribution networks, meaning augmentation of the distribution network is not required.

In the Zero-carbon Fuels scenario, additional gas transmission network capacity is required to transport natural gas from the point of production to the steam methane reformers that produce hydrogen, which we assume are located at city gates. At the distribution level, as in the Renewable Fuels scenario, hydrogen displaces end-use of natural gas on an equivalent energy basis, meaning no distribution network augmentation is required.

In all scenarios Western Australia and Victoria have the highest cost differentials due to their high levels of natural gas consumption.

Figure 19: Gas network costs, difference in annual cost in 2050 from Base Case ($2020)



Source: Frontier Economics' analysis

5.1.5 Hydrogen

As discussed in Section 4.4, our hydrogen sector modelling estimates the difference in costs resulting from investment in hydrogen production, storage and transport, and related carbon capture and storage, in each scenario relative to the Base Case.

Figure 20 presents a summary of our hydrogen production, storage and transport cost modelling by scenario and region. **Figure 20** shows differences in annual costs in 2050; positive values reflect an increase in costs on the Base Case, negative values reflect a reduction in costs. These costs only relate to the costs of building and operating hydrogen production, storage and transport facilities – the costs of electricity or gas used in the facilities is accounted for separately.

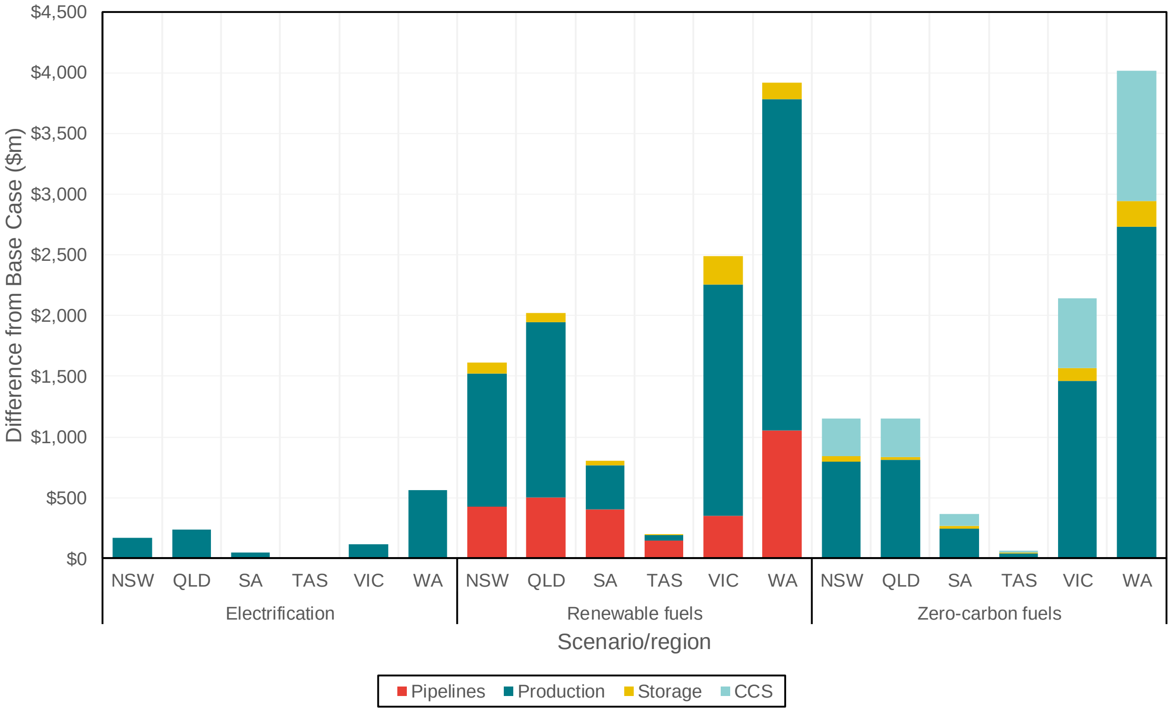
Differences in the costs of hydrogen production and storage investment in the hydrogen scenarios are due to three key reasons: capital and operating cost differences between the technologies, the relative efficiency of each technology, and the volatility of costs of input fuels. Our modelling methodology includes steps for optimising and trading off these costs to arrive at least-cost optimal levels of investment in hydrogen production and storage.

The level of investment in the Renewable Fuels scenario is driven primarily by the objective of minimising purchase costs of electricity, i.e. producing hydrogen when electricity is cheap to buy or generate. Consequently, the majority of electricity produced to be converted into hydrogen in our cost optimal modelling result comes from the energy source with the lowest levelised cost of electricity, solar PV.[10] The amount of hydrogen storage built is enough to satisfy the shifting of this production in time into periods in which it is consumed.

The price of fuel for the production of hydrogen in the Zero-carbon Fuels scenario is much more stable, as it reflects the cost of gas production in 2050. As hydrogen production facilities are relatively more expensive than hydrogen storage facilities, hydrogen production facilities are built to produce at high utilisation factors and storage is used to time-shift this production to meet demand. The Zero-carbon Fuels scenario also includes cost associated with carbon capture and storage, which are not incurred when electrolysis is used to produce hydrogen.

There is also a small amount of hydrogen production in the Electrification scenario to meet the hydrogen that we assume will meet some of the energy needs of industrial customers. Because this is a smaller amount of hydrogen less production capacity is required than in the other scenarios; and because it is to meet the needs of industrial customers, which are assumed to have much more constant demand for energy than residential and commercial customers, no hydrogen storage is used.

Figure 20: Hydrogen production, transport and storage capital and operating costs, difference in annual cost in 2050 from Base Case ($2020)



Source: Frontier Economics' analysis

10 The levelized cost of solar PV is primarily driven by its capital cost. The capital costs of each of the generation technologies that are options in our modelling are set out in Appendix A, **Figure 28**. As can be seen, the capital cost of solar PV is forecast to continue to fall over the period to 2050, having the lowest capital cost of the available generation technologies by 2050.

5.1.6 Concentrating solar thermal costs

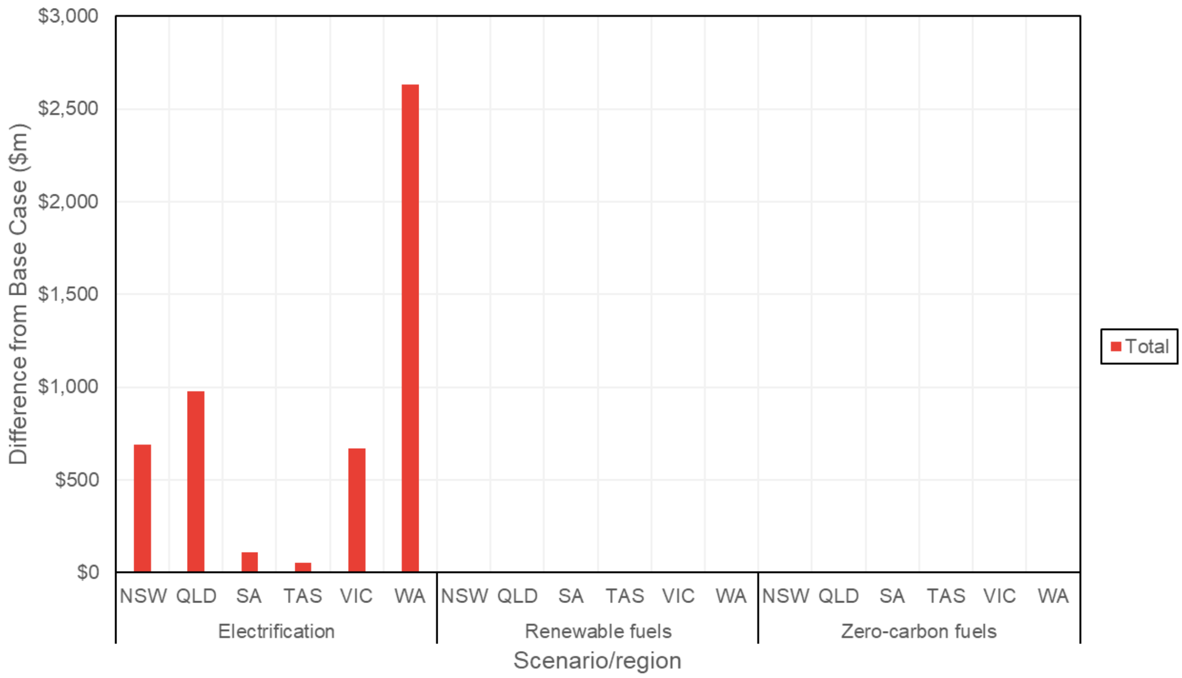
In the Electrification scenario, some of the heat requirements of some industrial customers are assumed to be met by solar thermal generators.

We have modelled the cost of this solar thermal generation – using the relevant input assumptions for solar thermal generation used in our electricity market modelling, and set out in Appendix A – to produce estimates of the cost of solar thermal for purposes, relative to the Base Case.

Figure 21 presents a summary of our solar thermal cost modelling by scenario and region. **Figure 21** shows differences in annual costs in 2050; positive values reflect an increase in costs on the Base Case, negative values reflect a reduction in costs.

As seen in **Figure 21** it is only in the Electrification scenario that additional solar thermal generation is required to meet some of the heat requirements of some industrial customers. In the other scenarios these heat requirements are assumed to be met by hydrogen.

Figure 21: Solar thermal generation cost, difference in annual cost in 2050 from the Base Case ($2020)



Source: Frontier Economics' analysis

5.2 Cost benefit assessment

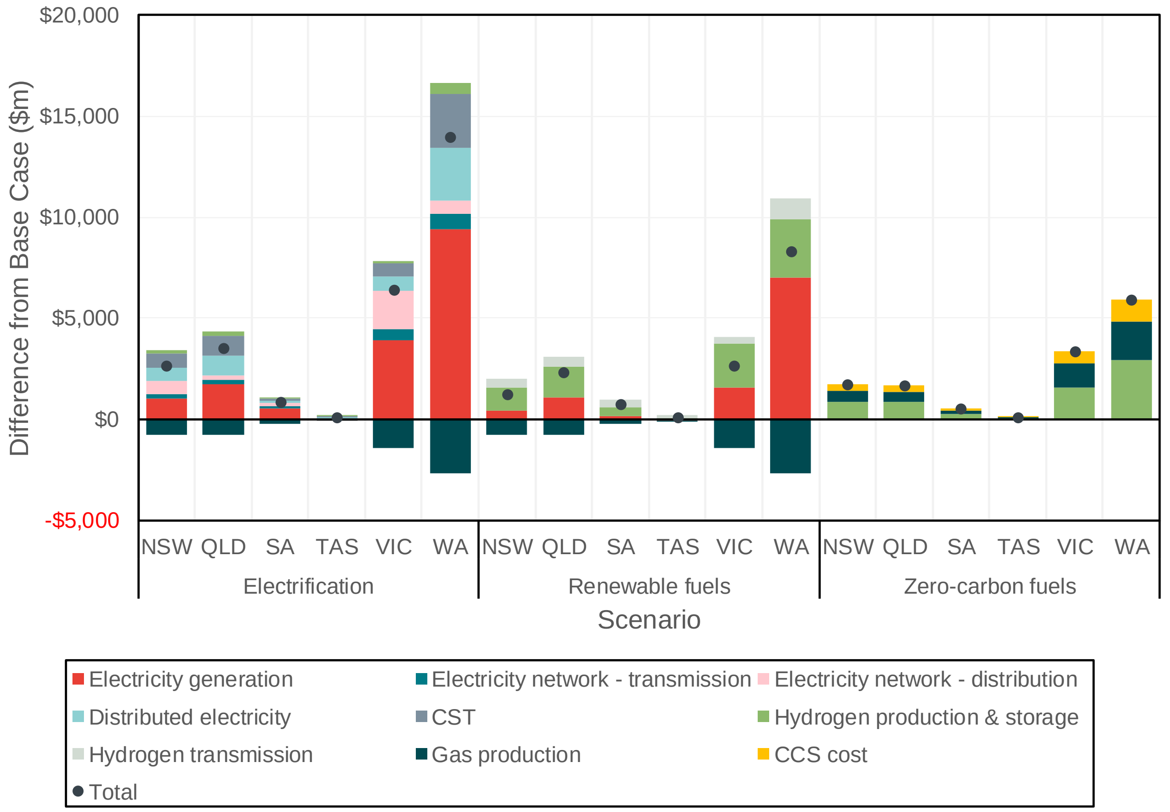
Using the modelling results outlined in Section 5.1, we populate a cost benefit model that assesses the net cost of each scenario by region and sector.

A summary of these costs and benefits is presented, by region, in **Figure 22**. **Figure 22** reports differences in annual costs in 2050 relative to the Base Case. Bars in the chart that are positive (above zero on the y-axis) mean scenario costs are higher than in the Base Case. Bars that are negative (below zero on the y-axis) mean scenario costs are lower than that the Base Case. The 'Total' dots represent net benefits (below zero) or net costs (above zero) by region.

In each scenario, higher net costs are generally associated with higher underlying natural gas consumption in the region, because the cost of substituting alternative fuels – either hydrogen or electricity – is more than supplying equivalent end-use energy from business-as-usual arrangements. This is partly because the business-as-usual arrangements embody significant sunk costs in the form of previously committed investment in gas transmission and distribution networks, and partly because the alternative fuels are more expensive to produce.

In all scenarios, and for each region, fuel switching occurs at a net cost – that is, fuel switching is more expensive than the business-as-usual Base Case. However, each of the scenario cases represent systems with low to zero carbon emissions, which is not the case in the Base Case.[11]

Figure 22: Cost-benefit analysis summary by components and regions ($2020)

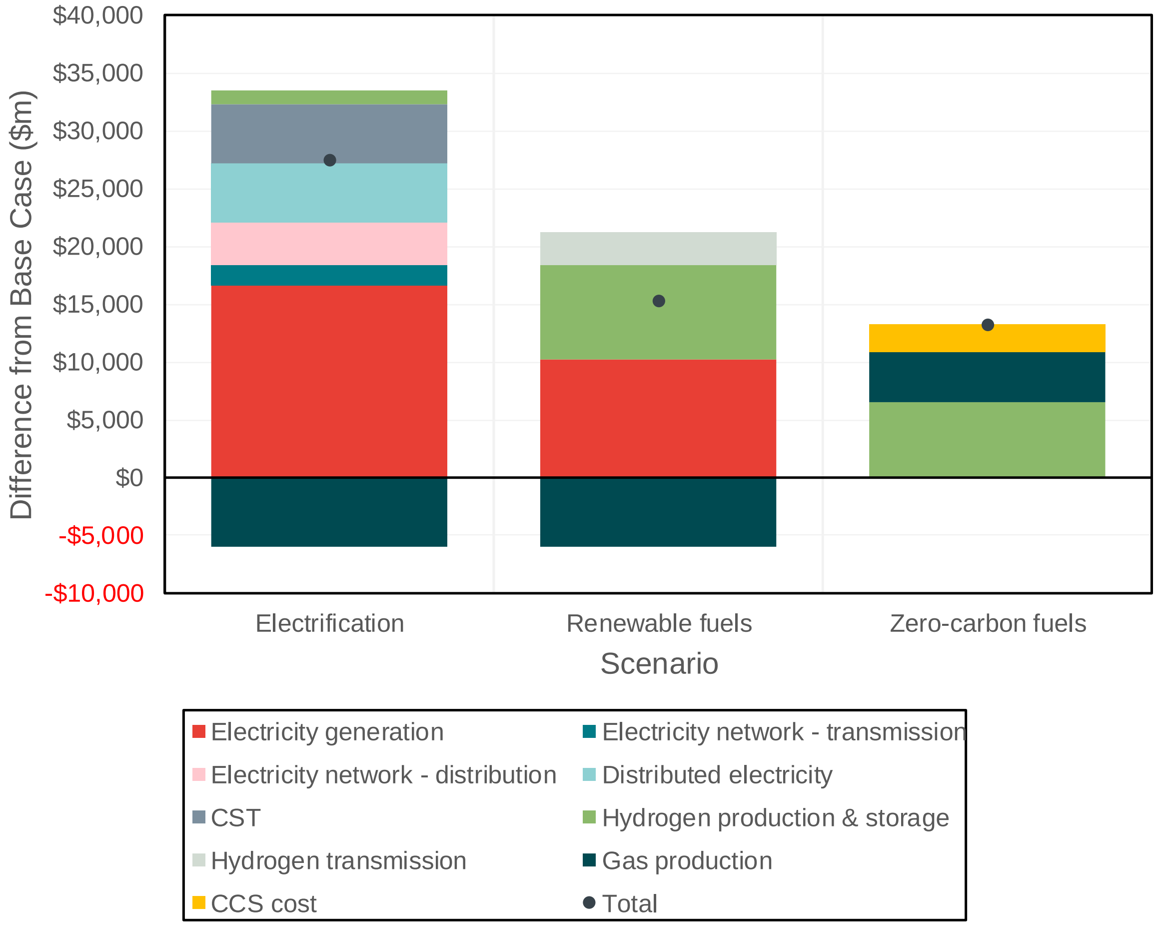


Source: Frontier Economics' analysis

Figure 23 presents the same data aggregated across regions; that is, it presents differences in annual costs in 2050 relative to the Base Case. From this figure, it is clear that the Electrification scenario has the highest net cost followed by the Renewable Fuels scenario and then the Zero-carbon Fuels scenario. The total cost in for each scenario, including a breakdown by the various cost components, is provided in **Table 9**.

[11] Our electricity sector modelling for the Base Case assumes, and delivers, a target of net zero emissions in 2050, but our assumption on ongoing end-use of gas by residential, commercial and industrial customers in the Base Case implies ongoing carbon emissions from the gas sector.

Figure 23: Cost-benefit analysis summary by components ($2020)



Source: Frontier Economics' modelling

Table 9: Cost benefit analysis summary by components – differences in annual costs in 2050, relative to the Base Case ($2020)

COST TYPE	ELECTRIFICATION ($ MILLION)	RENEWABLE FUELS ($ MILLION)	ZERO-CARBON FUEL ($ MILLION)
Electricity generation	$16,598	$10,187	$0
Distributed electricity	$5,129	$0	$0
Gas sector	-$5,936	-$5,936	$4,406
Hydrogen production	$1,151	$8,165	$6,495
Hydrogen transmission	$0	$2,880	$0
CCS cost	$0	$0	$2,392
CST	$5,129	$0	$0
Electricity network - distribution	$3,691	$0	$0
Electricity network - transmission	$1,785	$0	$0
Total	**$27,548**	**$15,296**	**$13,293**

Source: Frontier Economics' modelling

6 CONCLUSIONS

In this report we have considered three scenarios that are consistent with meeting Base Case electricity and gas consumption in 2050 while achieving net zero emissions. These scenarios are as follows:

- **Electrification scenario** – under this energy supply option, the intention is that all end-use natural gas consumption is replaced by customers switching from gas supply to electricity supply. However, for practical reasons, for industrial customers the Electrification scenario involves a mix of:
  - use of grid-sourced electricity
  - use of distributed electricity generation and storage
  - supply of heat through distributed solar thermal plant
  - use of hydrogen produced from on-site electrolysers supplied with grid-sourced electricity.

  Under each of these options end-use customers will no longer make use of gas infrastructure to meet their energy needs.
- **Renewable Fuels scenario** – under this energy supply option, hydrogen produced using alkaline electrolysis replaces all end-use natural gas consumption. Replacement occurs to ensure that the energy content of hydrogen is equal to the energy content of displaced natural gas.
- **Zero-carbon Fuels scenario** – under this energy supply option, hydrogen produced using steam methane reforming of natural gas with carbon, capture and storage replaces all end-use natural gas consumption. Replacement occurs to ensure that the energy content of hydrogen is equal to the energy content of displaced natural gas.

We compare outcomes for these three energy supply options against outcomes in a Base Case. In the Base Case we assume that the emissions target for the electricity sector will be net zero emissions by 2050. Based on this comparison we are able to determine the incremental cost of each of these scenarios, relative to the Base Case. The incremental costs that we consider are all relevant costs in the electricity, gas, and hydrogen sectors.

Based on the results of our analysis, we reach the following conclusions:

- Each of the three scenarios that we examine can reach net zero emissions from the stationary energy sector in 2050 (although entail additional costs in doing so). In contrast, in the Base Case, there are continued emissions associated with the end-use of natural gas that would need to be offset to reach net zero emissions.
- Gaseous fuels are essential as industrial feedstock in all of the scenarios. If gaseous fuels (either natural gas, hydrogen, biogas or renewable methane) are not available, the industries that rely on this feedstock would not be viable.
- For industries that use gas for heat, there is uncertainty about the practicality of switching these energy requirements entirely to grid-sourced electricity. Particularly for higher temperature requirements, it is unclear that grid sourced electricity is a practical alternative for all applications.
- All three scenarios that we consider are more costly in 2050 than the Base Case (that is, incremental costs relative to the Base Case are positive). This is consistent with the expectation that shifting away from our Base Case of consumption of electricity and gas to a scenario that meets net zero emissions from the stationary energy sector will be costly.
- Of the three scenarios, **the most costly is the Electrification scenario**. There are two key reasons that this scenario is costly:

  - First, even in 2050, the costs of generation to meet the energy needs of industrial customers using gas in the Base Case are significant. The costs of the renewable electricity used to supply grid-sourced electricity to residential and commercial customers and some industrial customers – primarily solar PV and wind – are forecast to fall significantly by 2050. However, there is also the need for significant storage to firm these intermittent generation sources. The same issue arises for industrial customers in rural and regional areas that are assumed to rely on solar thermal heat generation: solar thermal is also intermittent and so there is the need for additional capacity to manage periods of low solar irradiation.
  - Second, there are significant additional electricity network costs associated with the Electrification scenario. Meeting the energy needs for residential, commercial and some industrial customers that are currently meet by natural gas, using grid-sourced electricity, and doing so while continuing to supply Base Case electricity demand, requires additional capacity on the transmission and distribution networks, at material additional cost. Meanwhile, since investments in the gas transmission and distribution networks are sunk, there are no costs avoided by not using those network assets.
- **The Renewable Fuels scenario is lower cost than the Electrification scenario** by around $12.3 billion per annum in 2050, Australia-wide. What we see is that the combined cost of building electrolysers and supplying them with electricity in order to replace all gas consumption is lower than the combined cost of the mix of grid-sourced electricity, distributed electricity generation and storage, solar thermal heat generation and hydrogen that is required in the Electrification scenario. While there are significant additional costs of electricity production and hydrogen production, transmission and storage in the Renewable Fuels scenario, the ongoing use of the gas distribution network in this scenario means that there are not additional costs of energy distribution in this scenario (as there are in the Electrification scenario). Since the operation of electrolysers can be optimised to times of lowest cost electricity, the average cost of additional electricity is lower in the Renewable Fuels scenario than the Electrification scenario.
- **The Zero-carbon Fuels scenario is lower cost than both the Renewable Fuels scenario and the Electrification scenario**. In 2050, Australia wide, the Zero-carbon Fuels scenario is around $2 billion per annum lower cost than the Renewable Fuels scenario and around $14 billion per annum lower cost than the Electrification scenario. The cost saving for the Zero-carbon Fuels scenario relative to the Renewable Fuels scenario is largely driven by the fact that the gas used by the SMR is lower cost than the electricity used in the electrolyser. The fact that the natural gas delivered to the SMR can make use of existing gas transmission assets (which are no longer used for delivering natural gas to existing residential, commercial and industrial end customers) whereas the long distance transport of hydrogen from electrolysers requires additional investment in hydrogen transmission, also accounts for some of the cost saving. Against this, the SMR requires additional cost to capture and storage carbon, but this additional cost does not outweigh the savings from using gas rather than electricity.

Based on these results, we conclude the following:

- Making continued use of existing assets to deliver energy, such as the existing gas transmission and distribution network, where possible, can help avoid the material costs of investing in new assets to deliver energy, such as augmentation of the electricity transmission and distribution network.
- Our finding that both the Renewable Fuels scenario and the Zero-carbon Fuels scenario is lower cost than the Electrification scenario suggests that there is value in continuing to make use of Australia's gas network and Australia's natural gas resources to deliver gaseous fuels to end-use customers.
- Our finding that both the Renewable Fuels scenario and the Zero-carbon Fuels scenario is lower cost than the Electrification scenario suggests that policies to achieve net zero emissions should be broad-based and should not focus solely on promoting the electrification of all stationary energy end-use.

- There is significant uncertainty about technological developments and costs over the period to 2050. This means that the actual costs of the scenarios that we have examined will change over time, and new alternative scenarios will emerge over time. Policies to achieve net zero emissions that are broad-based, rather than focused solely on promoting the electrification of all stationary energy end-use, will enable energy sector participants and their customers to respond flexibly to these technology and cost changes to lower costs.

A ELECTRICITY MODELLING METHODOLOGY AND ASSUMPTIONS

We model long-term investment outcomes in 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 24**.

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 24: *WHIRLYGIG* schematic

Source: Frontier Economics

In order to model long-term investment in 2050, *WHIRLYGIG* models 2920 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 2920 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.

Base Case modelling assumptions

This section sets out the key input assumptions that we have used in our Base Case electricity market modelling.

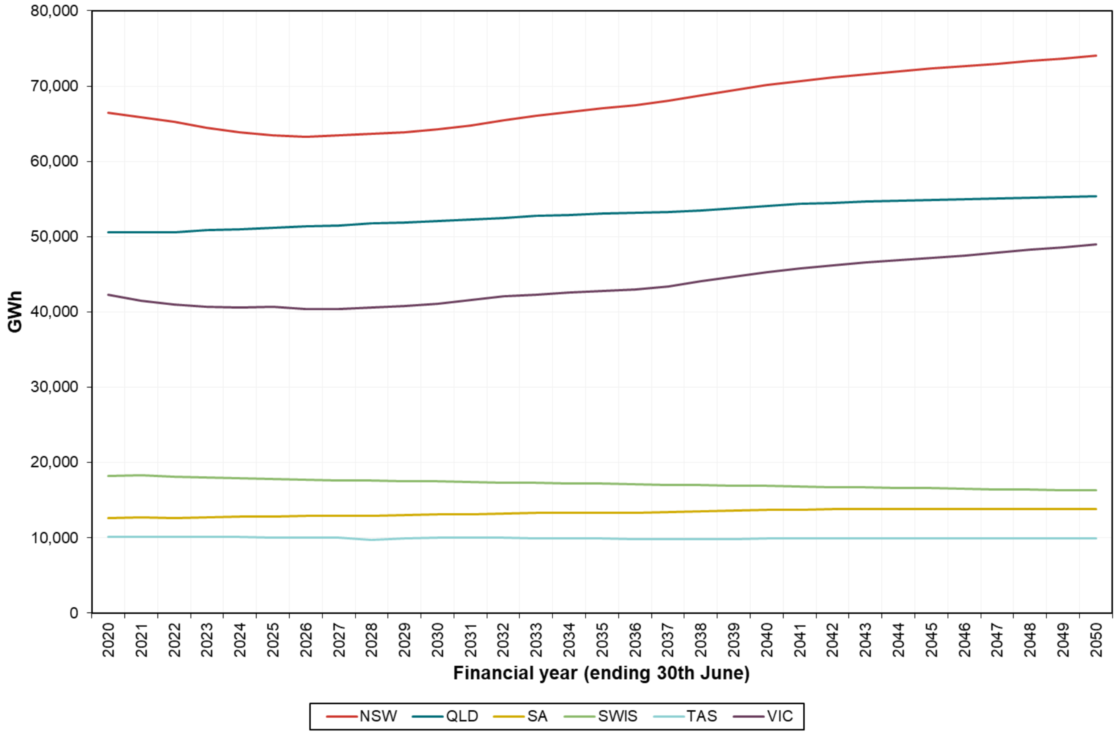
Our Base Case consists of a series of “most likely” or central predictions for all inputs and assumptions. We draw on information published by the Australian Energy Market Operator (AEMO) as part of its Integrated System Plan (ISP) for these Base Case assumptions.

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 25** (for annual consumption) and **Figure 26** (for annual maximum demand, for 50% probability of exceedance (POE) and 10% POE).

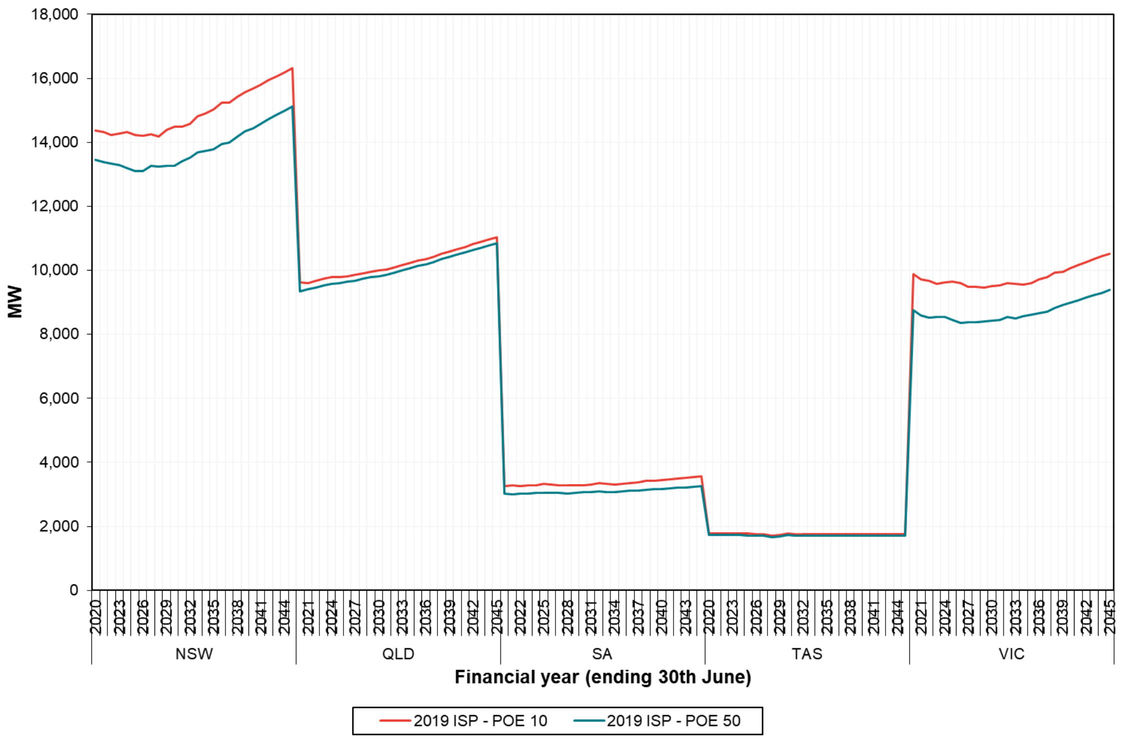
AEMO's demand forecast takes into account the contribution by rooftop PV and non-utility battery to annual consumption and peak demand. In other words, its operational energy forecast excludes consumption met by rooftop PV, and accounts for rooftop PV and non-utility battery's contribution to peak demand. 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 25: Energy consumption forecast (Operational, sent-out, GWh)



Source: AEMO 2019 ISP – December 2019 Update with Frontier Economics extrapolation post 2037/38.

Figure 26: Maximum demand forecast (Operational, sent-out, MW)



Source: AEMO 2019 ISP – December 2019 Update 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 with CCS
- Nuclear
- CCGT with CCS
- 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 CSIRO's report we are assuming that all of these technologies will be ready for commercial deployment during the modelling period. We don't consider this to be an unrealistic assumption: each of these technologies have already been deployed on a commercial scale somewhere in the world.

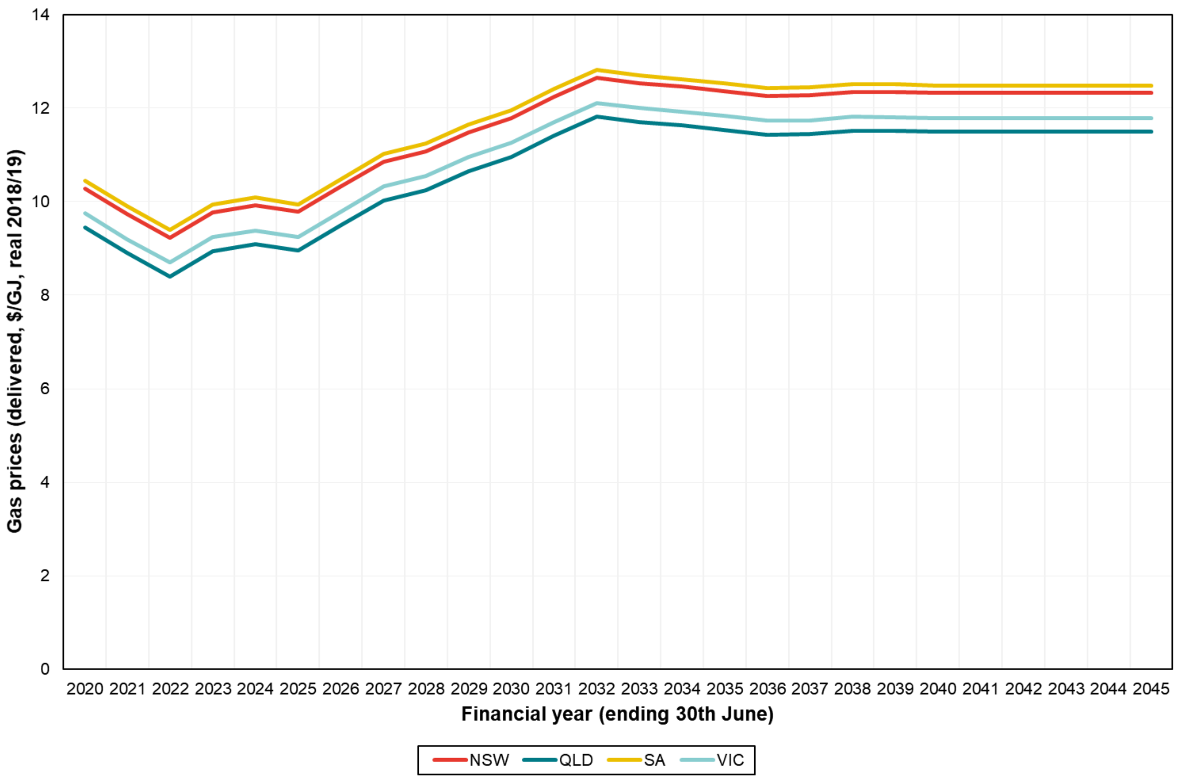
We have retained nuclear as an option but recognise that constructing a nuclear power plant is not consistent with current policy.

Gas prices

Our gas price forecasts are sourced from AEMO's Integrated System Plan (ISP) modelling assumptions.[12]

The average combined cycle gas turbine (CCGT) gas prices used in our modelling for reach region are shown in **Figure 27**. The corresponding open cycle gas turbine (OCGT) gas prices are 50 per cent higher.

Figure 27: Average gas prices for CCGT plants



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.

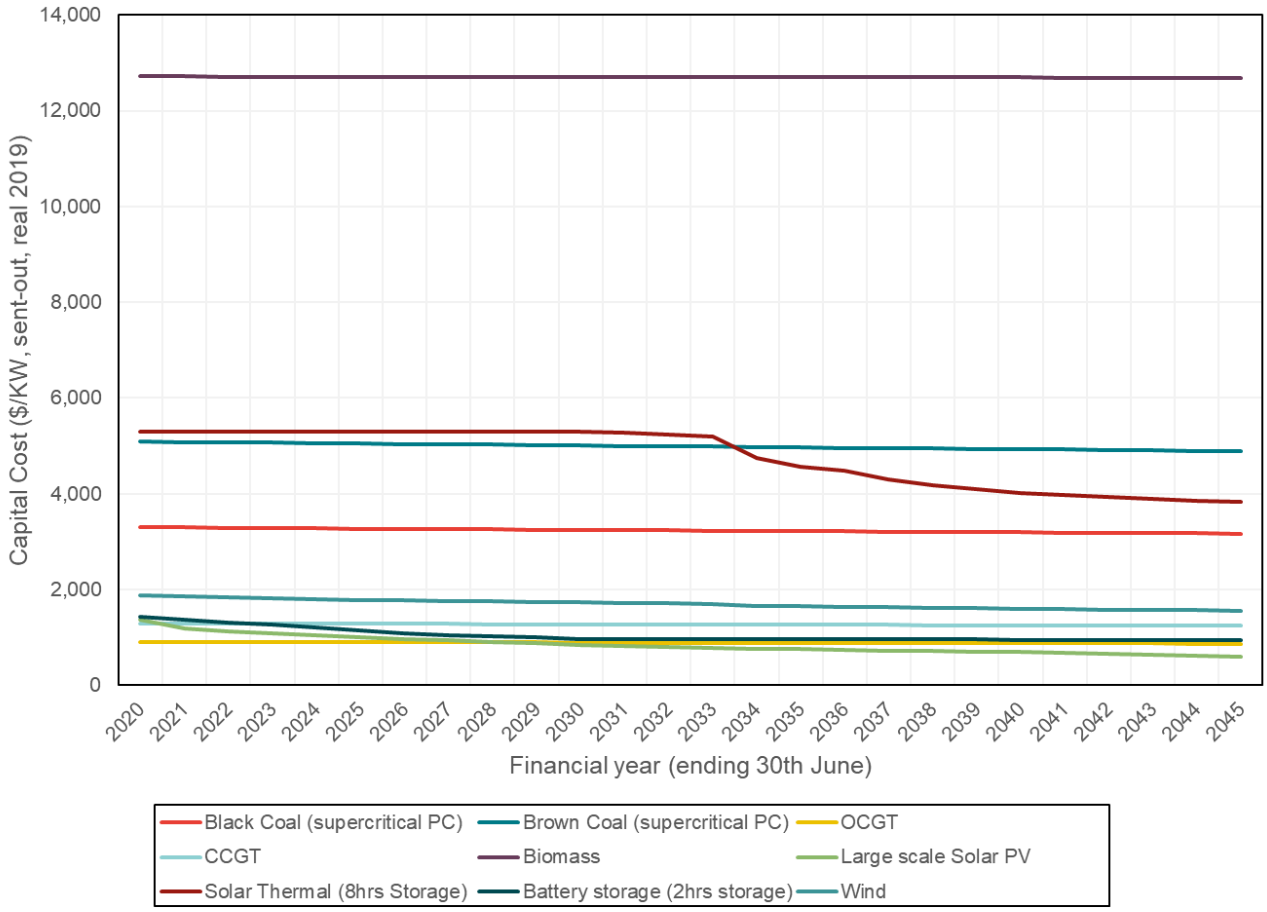
Figure 28 shows the capital cost used in our Base Case for thermal and renewable technologies.

12 AEMO, *Integrated System Plan modelling assumptions*. Available here: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/2018-Integrated-System-Plan--Modelling-Assumptions.xlsx

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.

These capital costs are used in all our modelling scenarios.

Figure 28: Capital costs



Source: AEMO 2019 ISP modelling assumptions

Renewable and climate change policies

Emission target

We model a net zero emissions target from the electricity sector, which we have assumed to mean that only low emissions generation is allowed to be built, as detailed previously.

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