21 January 2022

Renewables, Climate and Future Industries Tasmania
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Via: renewableenergy@stategrowth.tas.gov.au

Energy Networks Australia welcomes the development of Tasmanian Future Gas Strategy

Energy Networks Australia welcomes the opportunity to provide input during the consultation period on Tasmania's Future Gas Strategy – Discussion Paper (the Paper).

Energy Networks Australia is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

To date, the focus of decarbonisation has been on the electricity sector, but gas networks are on their own decarbonisation journey. Customers tell us that they are seeking a clean energy future and are engaged in achieving emission reductions from gas use. New renewable fuels, such as hydrogen and biomethane, have the potential to become mainstream and complementary energy solutions that will use existing energy infrastructure. Our gas networks members are leading the development of renewable gas projects and blending renewable hydrogen in the Adelaide and Sydney gas distribution networks, with further projects under development for Victoria, Western Australia and Queensland.

Tasmania has around 15,000 connections to the gas network, but as the Paper notes, nearly nine times as much LPG is supplied to households in Tasmania compared to natural gas. The totality of natural gas and LPG should be considered as they are both similar fuels providing similar services to customers in the form of heat, hot water and cooking utility. However, this small base and a recently constructed network creates an opportunity for Tasmania to gain global standing by demonstrating the conversion of the natural gas network to a hydrogen network, and to build on that and Tasmania's renewable energy potential to export hydrogen to the mainland and build a new energy export industry in Tasmania.

Pathways to decarbonise gas

Australia's gas industry associations have developed Gas Vision 2050[1], the industry's response to the Paris agreement on climate change. The vision outlines how transformational technologies will be deployed to reach net-zero emissions from using gaseous fuels in Australia. The technologies include:

» Hydrogen,
» Biomethane,
» Renewable methane, and
» Carbon Capture and Storage (CCS).

[1] https://www.energynetworks.com.au/projects/gas-vision-2050/

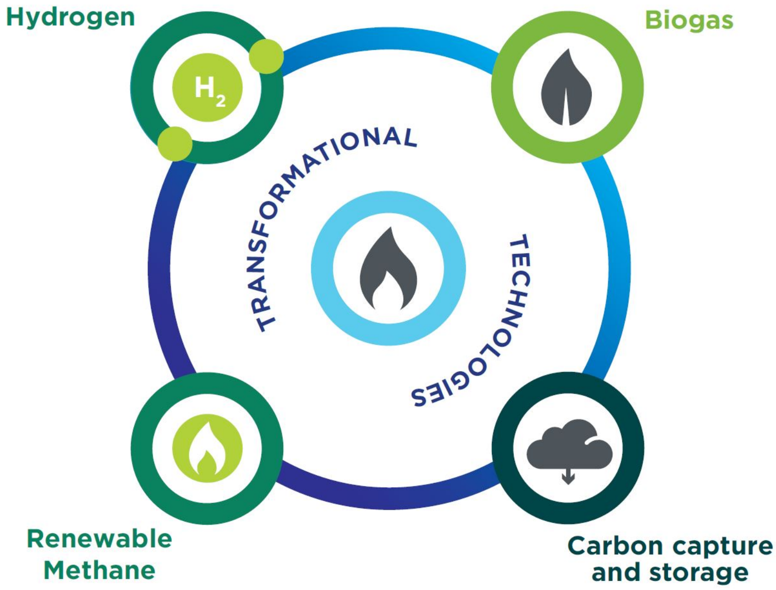

Figure 1: Transformational technologies (Source: Gas Vision 2050)

Decarbonising energy is essential for Tasmania to reach its emission objectives. This requires balancing the different elements of the energy trilemma– reliability (and safety), cost and environmental outcomes. For the major conversions required in the energy sector to reach net-zero emissions, the customer experience and the availability of resources should also be included.

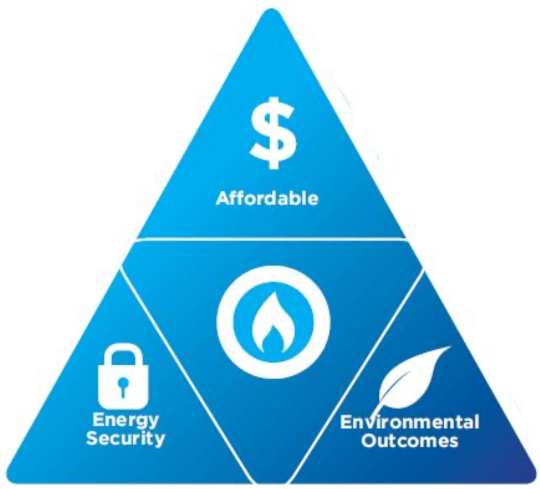

Figure 2: The energy trilemma (Source: Gas Vision 2050)

Reducing emissions from gas use can be achieved using one of three options:

- electrification of the end use of gas;
- replacement of natural gas with biomethane; and
- replacement of natural gas with hydrogen.

The options are often considered as standalone options but as we progress towards decarbonisation, all of these will have some role.

Hydrogen can achieve decarbonisation at *half* the cost of electrification

Economic analysis completed as part of *Gas Vision 2050 – Delivering a Clean Energy Future* showed that decarbonising gas can be done at half the cost compared to direct electrification of the gas load. This reflects the opportunity to repurpose existing gas infrastructure because electrification may impose system-wide costs for grid reinforcement on customer bills. The modelling showed that whole system costs would be lower when gas infrastructure is utilised (instead of replaced with electrical equivalent) to decarbonise the energy sector.

The cost stack (Figure 3) illustrates that very large investments would be required in electricity generation and storage for electrification compared to that required for green hydrogen. The overall result showed that continuing to use existing gas infrastructure could achieve net zero emission at half the cost of electrifying those services. This demonstrates the benefits and opportunities of utilising gas infrastructure to decarbonise. The analysis is consistent with many other international studies assessing the benefits of gas infrastructure to decarbonise the economy, concluding that decarbonising gas networks can be lower cost and less disruptive than electrification.

This is in direct contrast to the results by Oakley Greenwood (OGW) in their research paper for the Tasmanian Gas Strategy. The second attachment of this submission provides insights into the limitations of the OGW modelling and that its level of simplification make it unsuitable for informing policy design.

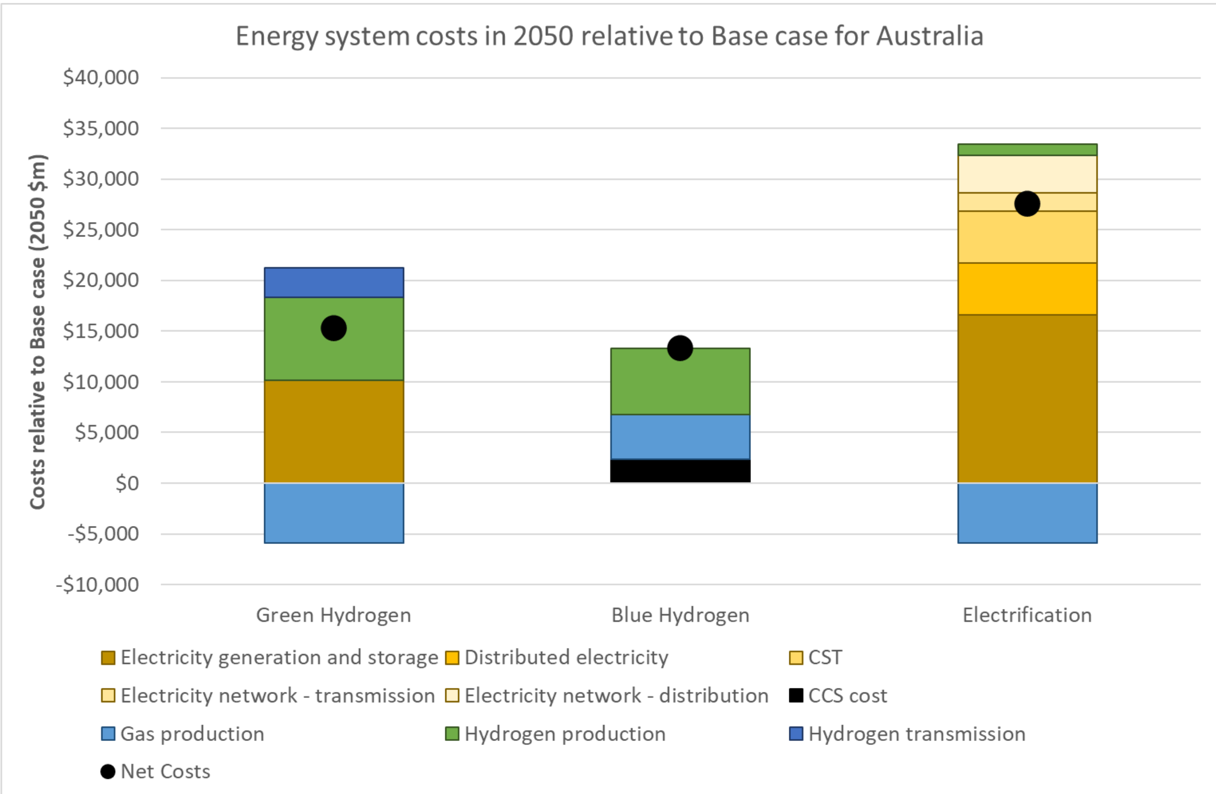

Figure 3: Costs of decarbonisation scenarios for Australia (Source: Gas Vision 2050: Delivering a Clean Energy Future)

Network progress on the hydrogen pathway

Gas distribution networks are leading the way in demonstrating the hydrogen pathway via blending hydrogen into the natural gas network.

A renewable hydrogen blend is already being delivered to 700 households in Adelaide[2] and a separate project in Sydney[3] is providing a blend to residential, commercial and industrial customers. This will be followed by more demonstration projects in the next few years to provide hydrogen to industrial customers. A 10 MW electrolyser will use renewable electricity to produce hydrogen from mid-2023 and enable blending of up to 10 per cent renewable hydrogen into the existing natural gas network in Albury/Wodonga to supply more than 40,000 existing residential, commercial and industrial customers[4].

Gas infrastructure businesses are also completing a detailed plan to deliver the three objectives, that are needed to meet the overall net zero aim described in Gas Vision 2050:

1. Enable blending of up to 10% by volume of renewable and decarbonised gases by 2030.
2. Enable 100% renewable and decarbonised gas supply to new residential developments before 2030.
3. De-risk a full network conversion to 100% renewable and decarbonised gases by 2050.

Individual gas network and pipeline businesses may have targets that diverge from these objectives, including some which are more ambitious. A mix of renewable and decarbonised gases will be needed to deliver net zero, including, but not limited to, green hydrogen from renewable energy sources (e.g. electrolysis using renewable electricity), biomethane from sustainable sources, or renewable methane.

Blending hydrogen in gas distribution networks provides the following benefits that support a broader hydrogen economy:

» It is the lowest cost option to create and use hydrogen. At blends of 10 per cent or less, no modification will be required to end use appliances and no expensive infrastructure (e.g. for refuelling) is required.
» Leads to cost reductions for hydrogen electrolyser plants from local experience in producing these plants and better understanding the balance of plant costs.
» Improves utilisation of variable renewable generation.
» Creates take-off opportunities to provide renewable hydrogen as an industrial feedstock or to support demonstration of fuel cell vehicles.
» Increases consumer and regulatory engagement by demonstrating opportunities provided by hydrogen.
» Hydrogen will be required as an industrial feedstock in any decarbonisation scenarios, including a policy driven electrification one. Demonstrating and reducing cost of hydrogen production is no regrets.

In the attached, we have identified key points for the Tasmanian government to consider in the development of its gas strategy. We have also attached a response to a number of limitations from

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[2] https://www.agig.com.au/hydrogen-park-south-australia
[3] https://jemena.com.au/about/newsroom/media-release/2021/first-green-hydrogen-for-new-south-wales-homes-and
[4] https://www.agig.com.au/media-release---new-hydrogen-blending-project

Energy Networks Australia

Oakley Greenwood. These limitations favour electrification. We have included responses to the consultation questions in the third attachment and have included a copy of Gas Vision 2050 for your information.

If you have any questions or would like a to discuss this further, please do not hesitate to contact ENA's Head of Renewable Gas: Dr Dennis Van Puyvelde at: dvanpuyvelde@energynetworks.com.au.

Yours sincerely,

Garth Crawford

General Manager Economic Regulation

Attachment 1: Key Points

1. **Customer choice should lead the way.** Customers are looking for renewable gas options. Governments are leading the development of market enabling mechanisms (e.g. certification, renewable gas targets) to provide customer confidence.
2. **All services provided by gas should be covered.** Both natural gas and LPG are delivered to Tasmanian homes and businesses for similar heating purposes. The Strategy should cover both fuels.
3. **Renewable gases offer a pathway to a fully decarbonised economy.** Australia's gas industry is already on a pathway to reach net zero emissions by introducing renewable gases (hydrogen and biomethane) through gas networks.
4. **Gas networks are ready.** Tasmania's gas network is only 20 years young and highly suitable for hydrogen blending trials and conversion to 100 per cent hydrogen.
5. **Lowest cost options should be a priority.** Renewable gas is complementary to renewable electricity in establishing a clean, robust, integrated energy system. Decarbonising gas network using renewable gas can be done at less than half the cost of an electrification alternative. These cost savings are mainly due to being able to repurpose gas infrastructure and minimising additional investment in electricity infrastructure.
6. **Renewable gases are essential.** There are many industrial applications that require the molecules provided by renewable gas for high temperature heat or industrial feedstock and these cannot be replaced by electricity.
7. **New gas supply options.** Renewable gases provide alternate gas supply options and increase the reliability of gas supply, and can create new export industries to mainland Australia.
8. **Policy decisions should be no-regret.** A strategy can identify a range of complimentary policies to support improved energy security across both electricity and gas at lowest cost.
9. **Single point cost analysis based on replacing the commodity cost are unreliable.** The modelling provided by Oakley Greenwood is simplistic and does not consider broader systems issues that are essential. This provides incomplete and misleading results.

Attachment 2: Limitations of the Oakley Greenwood report: *Tasmanian Gas Strategy: Background research, analysis and suggested next steps – Final report, October 2021*.

The report by Oakley Greenwood (OGW) provides useful background information on the issues around natural gas supply from the mainland via the Tasmanian Gas Pipeline, and the different roles of natural gas in Tasmania.

Unfortunately, their modelling of different options to decarbonise gas is simplistic and misleading. The main limitation is that the modelling compares the commodity price of electricity, gas, hydrogen or biomethane but does not address the network and wider system cost issues. Consideration of those wider costs is essential in policy design.

In this attachment, ENA identifies some limitations of the OGW modelling and provides additional information to provide the Tasmanian Government with a different view to highlight the potential role of hydrogen and bio-methane to meet Tasmania's gas needs.

Limitation 1: OGW focuses on commodity price, not total systems cost

The OGW modelling results are based on differences in commodity costs over a 20-year period. The 20-year cost savings are used to justify whether additional expenditure on electrical appliances would be justified.

Table 1: Modelled cost savings for residential customers over 20 years of electrification compared to gaseous fuels (Source: OGW report)

Fuel option	Oakley Greenwood modelled 20-year cost saving of electrification
Natural gas	$443
Hydrogen	$4,993
Renewable gas	$4,596
Renewable gas (higher cost of electrification)	$2,050

These numbers are misleading. The additional cost of electrical appliance compared to gas appliances also needs to consider additional installation costs. Capital cost of electrical alternatives are generally more expensive than gas appliances and this is reflected in government subsidies for electrical appliances[5]. For example[6]: the cost of an installed hot water heat pump is $4,196 while an installed instantaneous hot water gas heater is $2,182, which is around half the installed cost of the heat pump.

For electrification, an understanding is required of the additional generation, storage and transmission and distribution infrastructure required to replace the use of gas. Grattan[7] estimated that an increase of

[5] For example: Victoria's household energy savings package announced in June 2021
[6] Source: Table 32 of the NCC2022 Update – Whole of Home Component report.
[7] Grattan Institute (2020), Flame Out, pg 47

40 per cent in electricity peak demand in Victoria to electricity small user gas loads would be required. This may be less in Tasmania due to the lower level of gas network connections. But the Paper notes that nine times as much LPG is used as gas in homes so electrification should consider the total conversion of both gas supplied via the network and as bottled solutions. The estimate by Grattan is likely conservative and does not consider the potential of renewable drought during winter, which once again, may be less of an issue in Tasmania due to its high level of renewable generation.

Other appliance issues to be considered include:

- A conversion to biomethane (or renewable methane) will not require any modifications to gas appliances as the gas provided is chemically similar to natural gas.
- Hydrogen appliances have been built to provide the same services as gas appliances. These are currently at the prototype stage and not yet commercially available, although are being demonstrated in the UK[8]. The main differences between gas and hydrogen appliances reflect the different burning characteristics of hydrogen. Factories will need to be retooled to produce hydrogen appliances and this will require an upfront investment from appliance manufacturers. Once produced at scale, the cost of hydrogen appliances is expected to be similar to current gas appliances[9]. A strategy will be required to convert networks to hydrogen. The cost impact of switching to hydrogen appliances could be minimised by introducing dual fuel appliances which could be easily converted.
- Electrification requires a changeover of appliances at the household level, which may include upgrades to switchboards, the introduction of 3 phase power and the installation of much larger heat pumps to replace gas appliances. This could be an issue in high density living where space is already a premium. This changeover process will need to be managed and be aligned to additional growth in electricity generation while also managing the decommissioning of gas networks.

OGW's estimated cost savings may not be realistic and could easily be eroded when accounting for the higher cost of electrical appliances, as shown in Figure 4 below, and the potential upgrades and/or repairs to homes when replacing gas appliances with electrical ones.

[8] HyStreet, https://www.worldenergy.org/impact-communities/world-energy-stories/entry/dnv-hystreet-the-evolution-of-home-energy

[9] Energy & Utilities Alliance (UK)(2021), *The upfront cost of decarbonising your home*

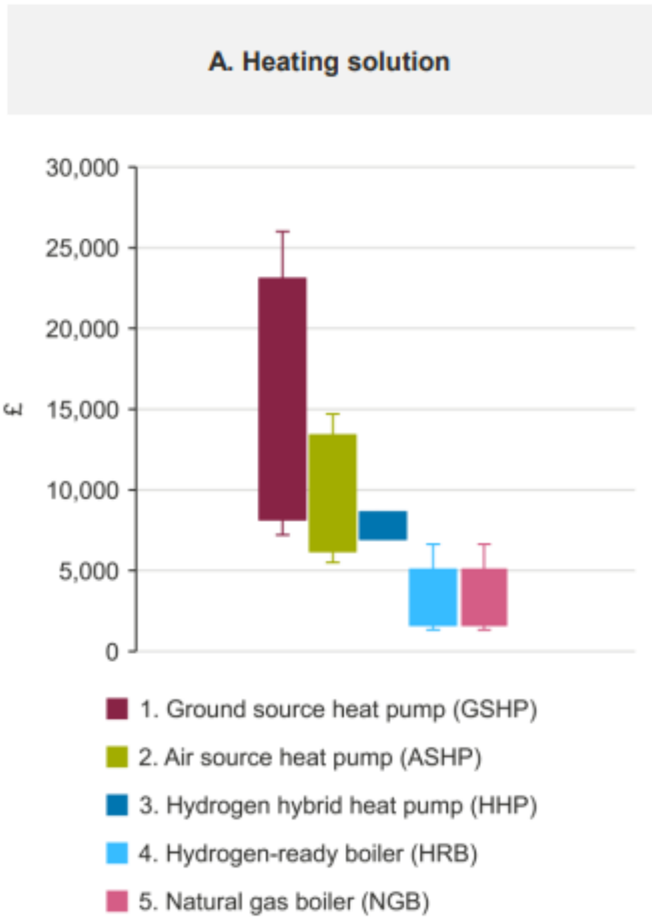


Figure 4: Capital cost of heating solutions (Source: Energy & Utilities Alliance (UK)(2021))

Limitation 2: OGW does not model energy network costs

OGW estimated the system cost per year[10] by multiplying the annual cost savings per house or business by the number of homes or businesses connected to the network. This indicates - excluding industrial customers - that electrifying all residential and commercial customers in Tasmania could result in total savings between $41.87 million and $54.23 million compared to converting to renewable gas. Unfortunately, this type of analysis does not represent a true cost of the electrification scenario.

[10] Total of "Difference in total cost of production" for Residential and Commercial customers. Pg 22 of OGW report.

Table 2: Modelled annual cost savings of electrification compared to gaseous fuels (Source: OGW report)

Fuel option	Oakley Greenwood's estimated annual cost saving ($m)
Natural gas	$3.7
Hydrogen	$41.87
Renewable gas	$54.23

Modelling by Frontier Economics as part of Gas Vision 2050 considered the broader systems costs and not just the fuel production costs. The Frontier work considered the change in cost of natural gas production, natural gas transmission and distribution networks, electricity transmission and distribution networks, and standalone industrial production of hydrogen to replace gas for industrial processes.

It was assumed that no modifications were required to the gas distribution network as these networks are undergoing modernisation by replacing steel parts of the network with modern plastic materials that can handle hydrogen. In the case of Tasmania, this assumption is appropriate as it is a young network. No conversions of appliances were included in the analysis and this favours the electrification scenario where appliances are generally more expensive (as shown in Figure 4).

Blending of hydrogen is a low-cost option to commence the hydrogen economy as no modification to end user appliances, or additional infrastructure (e.g. hydrogen refuelling stations) are needed.

The Frontier modelling showed that renewable hydrogen scenario for Tasmania costed $88 m pa[11] compared to the electrification scenario of $118 m pa. This means an additional $30 m pa for the electrification scenario compared to converting networks to renewable hydrogen. The result from Frontier is in direct contrast to the one by OGW which found cost savings, not extra costs, from electrification.

[11] This is similar to the figure calculated by OGW of $88.3 m for the hydrogen cost per annum (page 21)

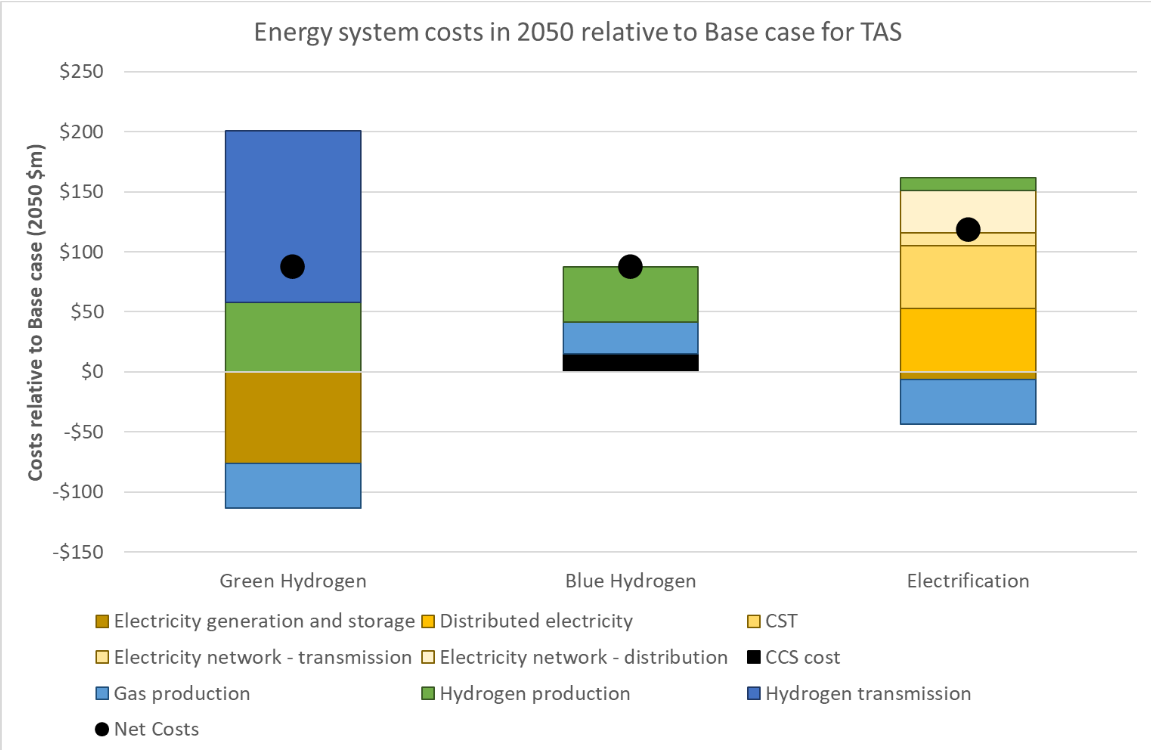


Figure 5: Cost estimates of reaching net-zero emissions from gas use in Tasmania (Source: Gas Vision 2050).

OGW's estimated cost savings do not include systems costs and as such are an incomplete representation of the any conversion costs involved in electrification, making the cost estimates an unsound basis for policy-making.

Limitation 3: OGW fuel costs are unrealistic and do not recognise opportunities to reach cost parity of renewable gases

OGW assumes a single averaged cost point in their analysis. However, these price assumptions appear low for electricity and high for gaseous fuels, which creates a bias towards electrification.

Table 3: Assumed fuel input costs (Source: OGW report)

Fuel	Assumed cost
Electricity	$40 per MWh
Natural gas	$12 per GJ
Hydrogen	$3 per kg (roughly $21/ GJ)
Renewable gas	$24.08 per GJ

Variable electricity tariff

Assuming a uniform cost of electricity generation can be a good proxy of the averaged electricity cost across a year. But the wholesale price of electricity changes across the day and throughout the year. Indeed, the price in the NEM changes every five minutes to reflect different generators bidding into a market.

Gas is typically used at periods of high electricity demand, i.e. in the mornings, evenings and during colder months (highlighted in blue in Figure 6). It is at these times that higher wholesale prices occur. While customers are covered from this at the moment through regulated retail tariffs, any growth in consumption (through electrification) during these peak periods will results in increased retail tariffs over time for all customers.

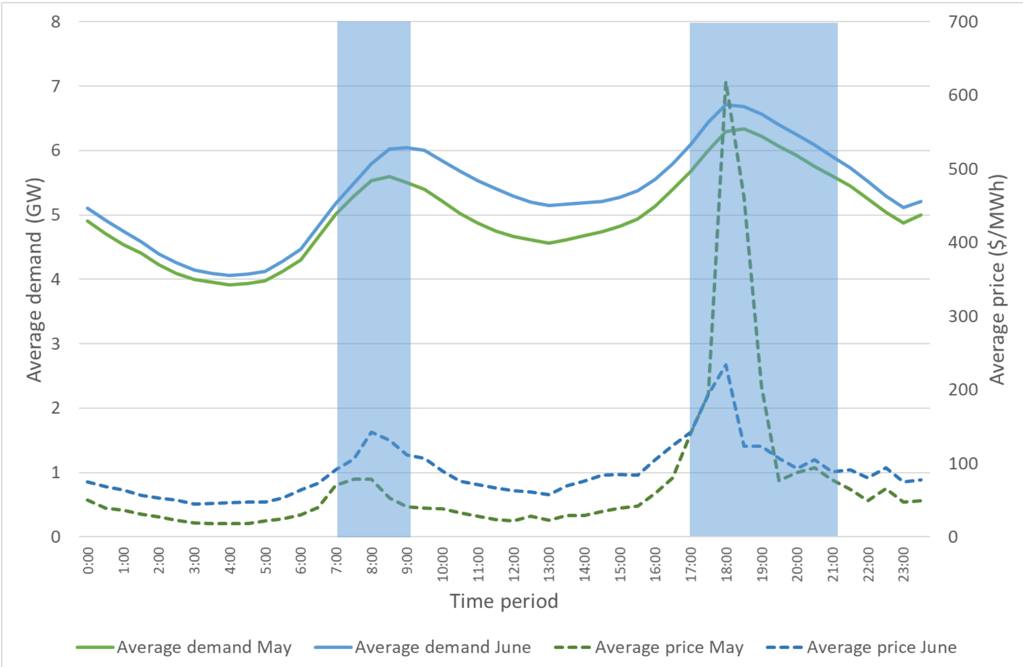


Figure 6: Victorian electricity price and demand (Source: AEMO data)

Using the data of Figure 6, the average electricity price for May and June 2021 is $80/ MWh, whereas the average price throughout the peak periods during these months is $157/ MWh, nearly double that of the daily average.

The assumption by OGW to use an average of electricity price of $40/ MWh favours the electrification option and does not appear realistic when considering the specific role of gas and its peaky nature.

Achieving cost parity of renewable methane with natural gas.

The renewable gas price of $24/ GJ is double the cost of natural gas, which also appears on the high side. This may be a realistic cost for small standalone biomethane plants but there are opportunities to reach cost parity with natural gas that have not been considered by OGW.

Future Fuels CRC has developed an assessment framework for bio-methane injection in gas networks project (RP1.2-03)[12], and completed the techno-economic viability assessment for different case studies.

A scenario analysis demonstrated that the cost of production can approach the price of natural gas in Australia, if biogas plants can offset their operation costs with the other product streams the injection of bio-methane (e.g. profits from the digestate, or the use of gate fees for feedstock delivery to the plant). In addition, renewable heat incentives (RHI) such as those from Denmark and the UK would lower the production cost by $4-8/GJ if applied in Australia, suggesting that policy support for the development of the bio-methane industry in Australia would be a significant factor in making bio-methane injection projects viable.

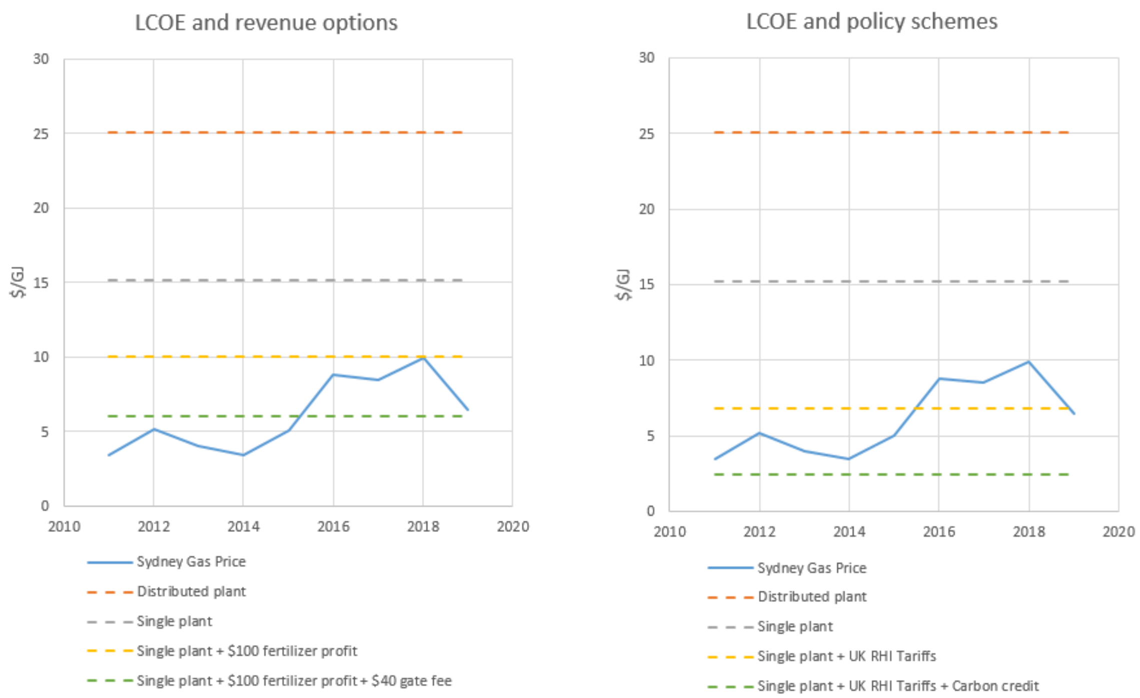


Figure 7: Reaching gas price parity using biomethane (Source: Future Fuels CRC, RP1.2-03)

The figure above illustrates that bio-methane injection can be commercially competitive when other revenue options or supportive policy mechanisms are introduced. The assumption by OGW does not consider these opportunities to achieve cost parity and as such the analysis potentially biases the analysis in favour of electrification options.

[12] Future Fuels CRC (2021), *Assessment framework for bio-methane injection in gas networks.*

Hydrogen production cost inconsistent with other analysis.

There is a lot of momentum to develop a hydrogen industry in Australia. The Commonwealth Government produced a *National Hydrogen Strategy* in November 2019 and every state or territory has some sort of hydrogen strategy or interest. The focus is on capturing the possible export market while recognising the role hydrogen can also play to decarbonise the domestic economy by applying it to gas networks, for remote power, for mobility and as a feedstock to industry (e.g. green steel).

The Commonwealth Government[13] has set a target of achieving a production cost of hydrogen of $2 per/kg[14]. The *National Hydrogen Strategy*[15] illustrated that a range of options would become cost-competitive at this cost by 2030.

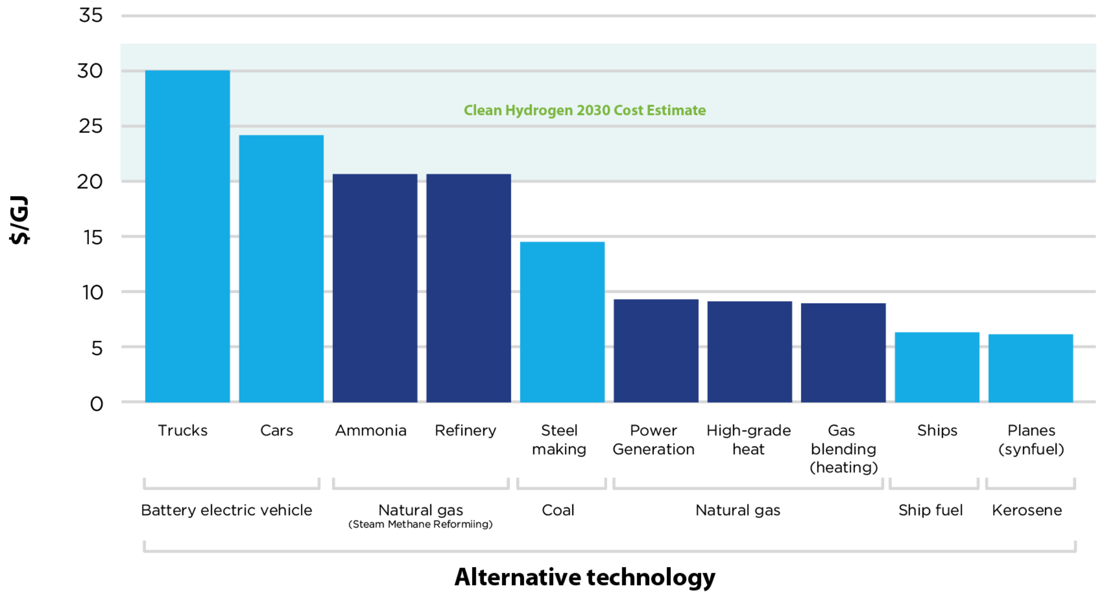


Figure 8: Cost competitive options for hydrogen at $2/kg (Source: Australia's National Hydrogen Strategy)

The present cost of renewable hydrogen production means it is only economically competitive against incumbent fuels in a small proportion of industries. The Clean Energy Finance Corporation[16] (CEFC) found that remote power, line haul vehicles, materials handling and return to base vehicles were the only opportunities that represented a net economic benefit for hydrogen based on 2020 data. This primarily reflects the high fuel costs of those industries. Reducing the cost of hydrogen production through reductions in electrolysers manufacturing costs, bringing down the cost of renewable electricity and optimising the capacity factors of electrolysis plants makes the economic benefits of those sectors greater and creates new economic opportunities for other sectors.

Using the CEFC data, there is an economic gap to replace natural gas with hydrogen in gas networks. This is partly due to the much higher production cost on a $/GJ of hydrogen compared to natural gas but also

[13] Department of Industry, Science, Energy and Resources (2020), *Technology Investment Roadmap Discussion Paper.*
[14] This equals $16.70/ GJ using the lower heating value of hydrogen, which is 120 MJ/ kg.
[15] Council of Australian Government – Energy Council (2019), Australia's *National Hydrogen Strategy*
[16] Clean Energy Finance Corporation (2021), *Australian hydrogen market study – sector analysis summary*

does not recognise the potential economic benefit from reduction in carbon emissions when using renewable hydrogen. As renewable hydrogen technology develops, the economic gap for hydrogen in networks reduces to reach parity with natural gas in the early 2030's.

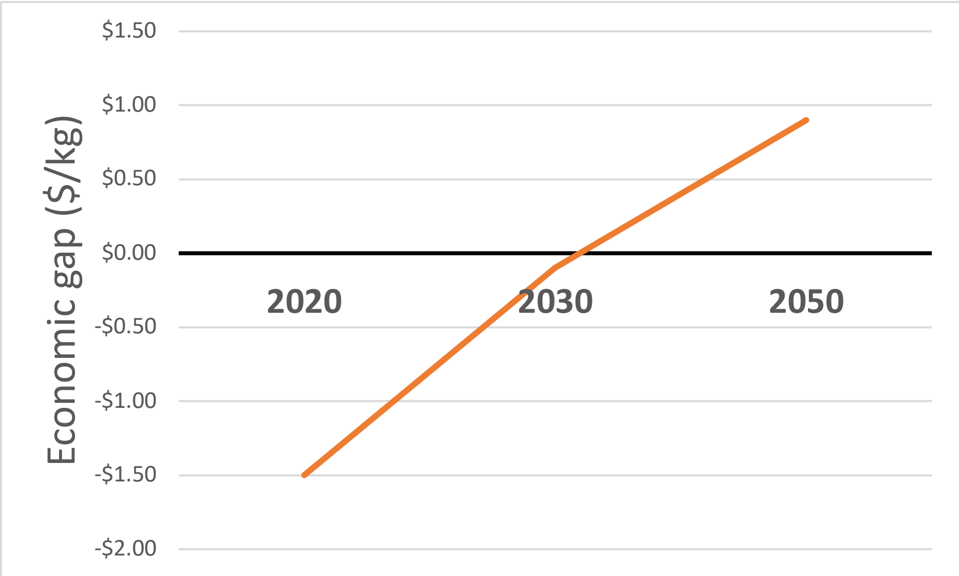


Figure 9: Closing the economic gap for hydrogen to replace natural gas in networks.

The OGW assumption of hydrogen at $3/ GJ is out of step with national targets of reaching less than $2/ GJ and also does not recognise the opportunity of hydrogen to become commercially competitive for use in natural gas networks in the early 2030's. The OGW assumptions may bias the scenarios present toward an electrification outcome.

Furthermore, the OGW report indicates a breakeven point between the electrification and hydrogen scenarios at a hydrogen cost of $2.10/ kg (pg 25). At this point there is no additional money to spend on electrical appliance upgrades over and above what would need to be spent on hydrogen appliance upgrades.

Limitation 4: OGW does not recognise that a planned transition is needed for electrification

In OGW's research paper, they note that:

> *… inevitable leading to additional appliance cost and in some cases the bringing forward of appliance replacement relative to the electrification case, which could occur at the end of their life (pg 26)*

This shows a lack of understanding of how gas network conversions will happen. It is true that a planned appliance replacement program would be needed to convert to hydrogen and that in some cases, this would bring forward the appliance replacement cost. However, a similar program of appliance replacement would also be needed for policy driven electrification as it will be impractical to continue to operate gas networks over extended periods with declining demand to allow customers electrify as their appliance reach the end of their appliance life.

Limitation 5: OGW does not recognise the broader opportunities for Tasmania as a renewable gas exporter

Tasmania is well established as a renewable electricity exporter. It could also create commercial opportunities to become a renewable gas exporter.

Tasmania's hydrogen potential

Tasmania's renewable hydrogen action plan (2020) includes a vision for Tasmania to be a global supplier of renewable hydrogen from 2030. To achieve this vision, short term goals between 2022 and 2024 include:

- Tasmania has commenced production of renewable hydrogen.
- Locally produced hydrogen is being used in Tasmania.
- Export based renewable hydrogen production projects are well advanced.

Blending hydrogen in gas distribution networks provides the following benefits that support a broader hydrogen economy:

- It is the lowest cost option to create and use hydrogen. At blends of 10 per cent or less, no modification will be required to end use appliances and no expensive infrastructure (e.g. for refuelling) is required.
- Leads to cost reductions for hydrogen electrolyser plants from local experience in producing these plants and better understanding the balance of plant costs.
- Improves utilisation of variable renewable generation.
- Creates take-off opportunities to provide renewable hydrogen as an industrial feedstock or to support demonstration of fuel cell vehicles.
- Increases consumer and regulatory engagement by demonstrating opportunities provided by hydrogen.
- Hydrogen will be required as an industrial feedstock in any decarbonisation scenarios, including a policy driven electrification one. Demonstrating and reducing cost of hydrogen production is no regrets.

Potential of biomethane in Tasmania

OGW does not recognise the potential of biomethane in Tasmania. Australia's bioenergy roadmap[17] published in late 2021 provides a breakdown of theoretical resource potential by state and biomass type. The potential for Tasmania is estimated at 92 PJ pa, which should be considered highly optimistic. Nevertheless, this is much higher than Tasmania's natural gas demand of approximately 7 PJ.

Given the above analysis on reaching price parity with biomethane and natural gas, there could be an economic opportunity for Tasmania to develop a domestic gas industry based on biomethane.

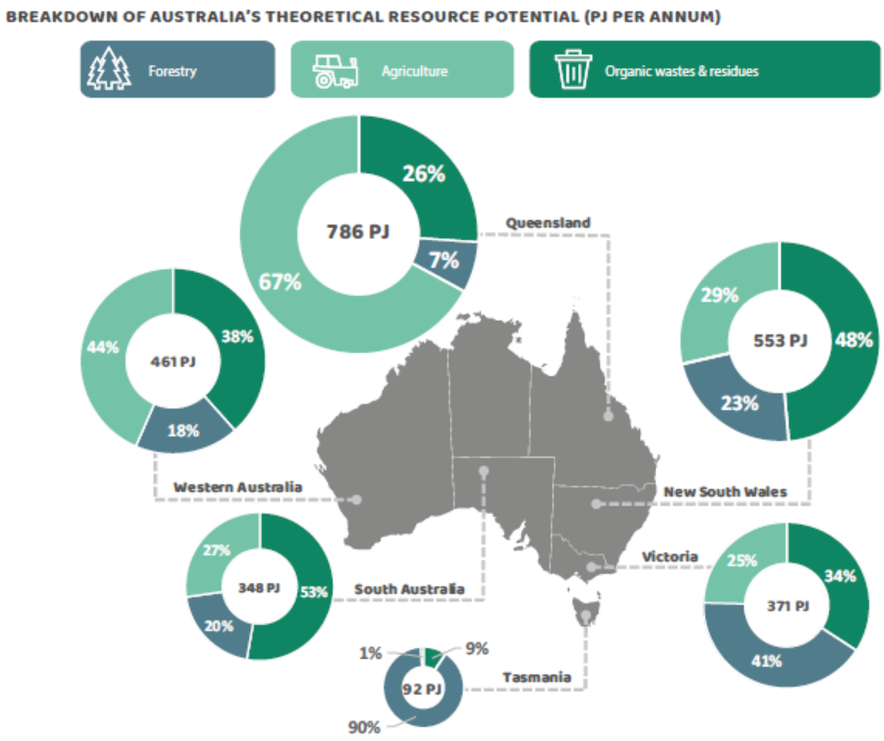


Figure 10: Australia's theoretical bioenergy resource potential (Source: Arena (2021), Australia's Bioenergy Roadmap, pg 23)

Biomethane can be a real opportunity. Denmark is a good example (as are many other European countries such as Germany, France and the UK) of biomethane potential. In 2028, 32 biogas plants produced an additional 7.2 PJ of biomethane over and above the 5 PJ of biomethane that is being produced for power generation. While Denmark has a lot of agricultural waste from livestock, the example illustrates that only a small number of plants are needed to support Tasmania's gas demands. Additional biomethane production could be exported to Australia's mainland as renewable energy.

[17] ARENA (2021), *Australia's bionenergy roadmap*

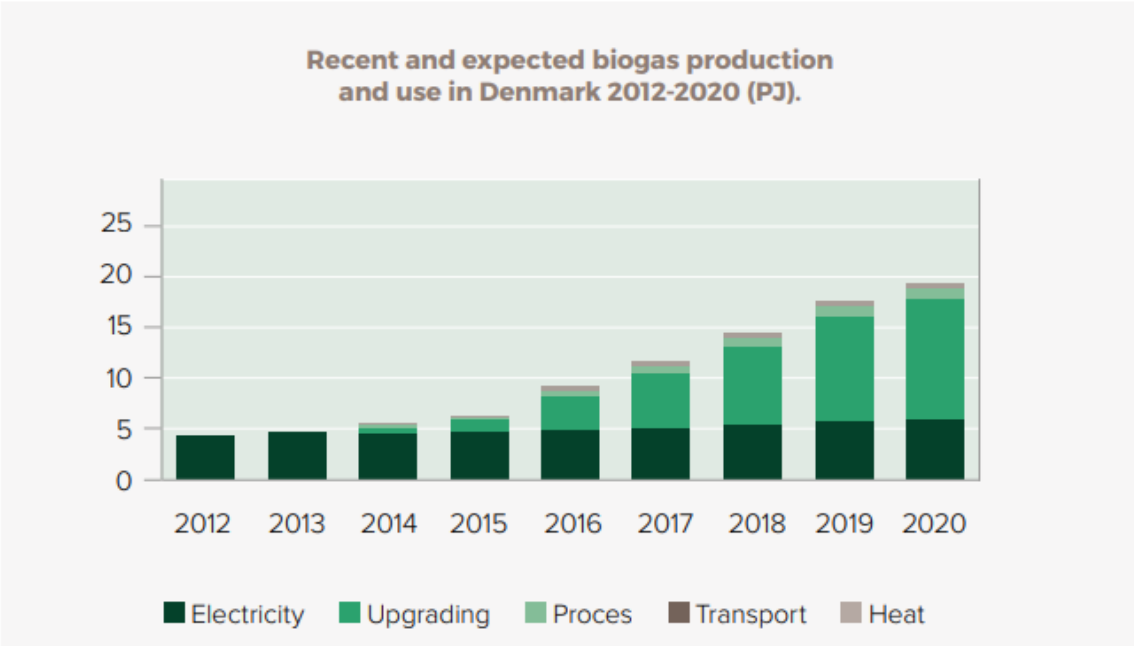


Figure 11: Biomethane production in Denmark (Source: Biogas Go Global (2020), Biogas Production: Insights and experience from the Danish Biogas Sector)

Attachment 3: Responses to discussion paper questions

Drivers influencing our gas industry

1. What factors do you think need to be considered in developing a strategy for the future of gas in Tasmania?

The discussion paper identified an important set of factors to be considered.

Modelling is a useful tool to inform policy. Making assumptions are essential in any modelling undertaken as it effectively represents a simplification of the real-world energy system. These assumptions and limitations can impact on the usefulness of the modelling work and very simplified modelling may draw misleading conclusions. The modelling provided by Oakley Greenwood to support the discussion paper is overly simplified and does not recognise some of the complex systems issues that need to be considered for the energy system.

Energy Networks Australia has identified five limitations of the modelling that should be addressed. These are provided above.

2. What changes are you, or members of your industry, observing related to global and domestic market settings for fossil fuels that could potentially impact on the outlook for gas in Tasmania?

To limit global warming, there is increased focus and commitment to reduce greenhouse gas emissions. The focus has been on the energy sector, especially the electricity generation sector through technology developments such as rooftop solar PV and wind power. But that is changing with growing attention on reducing emissions from gas, across the whole supply chain.

There are many technologies to reduce emissions including energy efficiency and carbon offsets. But to reach net-zero, the fuel itself needs to be decarbonised. There are three available pathways that can achieve this.

» Renewable methane, which provides a greenhouse gas neutral equivalent to natural gas and includes biomethane and synthetic renewable methane.

» Hydrogen, which produces no greenhouse gases when used as a natural gas substitute.

» Direct electrification, which substitutes natural gas use with electrical alternatives and can result in low emissions commensurate with the emission intensity of the electricity grid.

Due to the size of the transformation of the energy sector, and especially when considering the totality of electricity supply, gas supply and liquid fuel supply, all of these technologies will contribute towards reaching net zero emissions. The challenge is to find the right mix of these pathways to reach net zero emissions while ensuring energy security and minimising the overall cost of the energy system.

This is creating new commercial opportunities for renewable gas to meet domestics supply and/ or meet energy demands of the Asia Pacific region.

Who uses gas and for what?

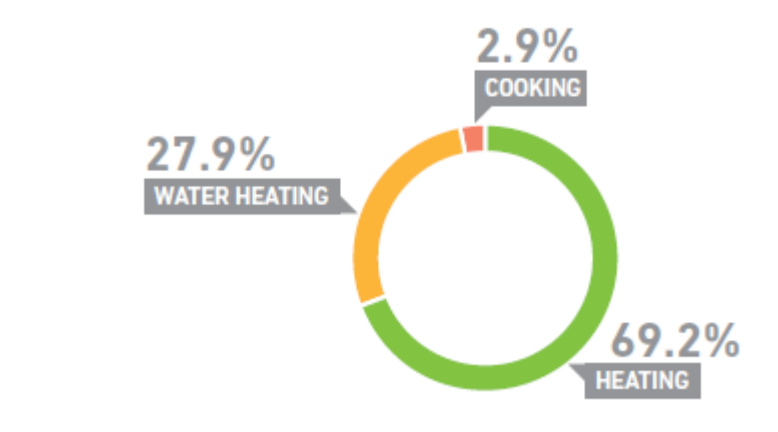
3. If you use gas in the home, what do you use it for? Are you connected to the natural gas network or do you have LPG delivered?

Attachment 3: Responses to discussion paper questions

Residential customers mostly use gas for space heating, hot water or cooking.

The figure below (from Sustainability Victoria) notes that nearly 70 per cent of gas consumption is used for heating, with 28 per cent for hot water and the remaining 3 per cent for cooking. This is based on Victorian data from 2015 but similar energy patterns could be expected in Tasmania with similar climate conditions. Heating is also seasonal with most of that gas being used during the colder winter months. ENA found that four times as much gas is used by residential customers in winter months compared to summer months.

Figure 2: Breakdown of the average gas bill in Victorian households



(Source: Sustainability Victoria (2015), Victorian Household Energy Report.)

The discussion paper noted that 9 times as much LPG is used in homes compared to natural gas. Both LPG and network provided gas are used for similar purposes by customers.

Tasmania's gas strategy should cover both network gas and LPG as they provide the same services to customers and have similar pathways to reduce emissions (i.e. hydrogen, renewable methane or electrification).

4. If you are a business that uses gas, what industry are you in? What do you use gas for?

Businesses generally use gas for similar purposes than homes, i.e. cooking, hot water or heating.

In some industries, gas is used to generate high temperature flames or as a feedstock to manufacture goods, such as ammonia. Electrification of these high temperature processes and feedstock is not possible and a gaseous fuel will continue to be needed for these industries.

In general, gas consumption is more uniform across the year by commercial and industrial customers although an increase is observed during colder months.

5. Are your gas appliances coming up for replacement? Are you considering switching to electricity or another alternative?

Any switching from gas to electrical appliances should also consider broader issues such as the requirement of a 3-phase electricity connection, whether the ducting from gas heating can be repurposed, space and noise limitations of electrical appliances and whether other repairs will be required after the replacement of gas appliances with electrical ones.

Switching to electrical appliances may also require energy efficiency upgrades of the home. A recent study by RACE[18] found that a full range of energy efficiency and electrification upgrades and solar rooftop PV for an existing home could cost over $58,000. There is a wide variation in energy efficiency options but these need to be considered if switching away from natural gas.

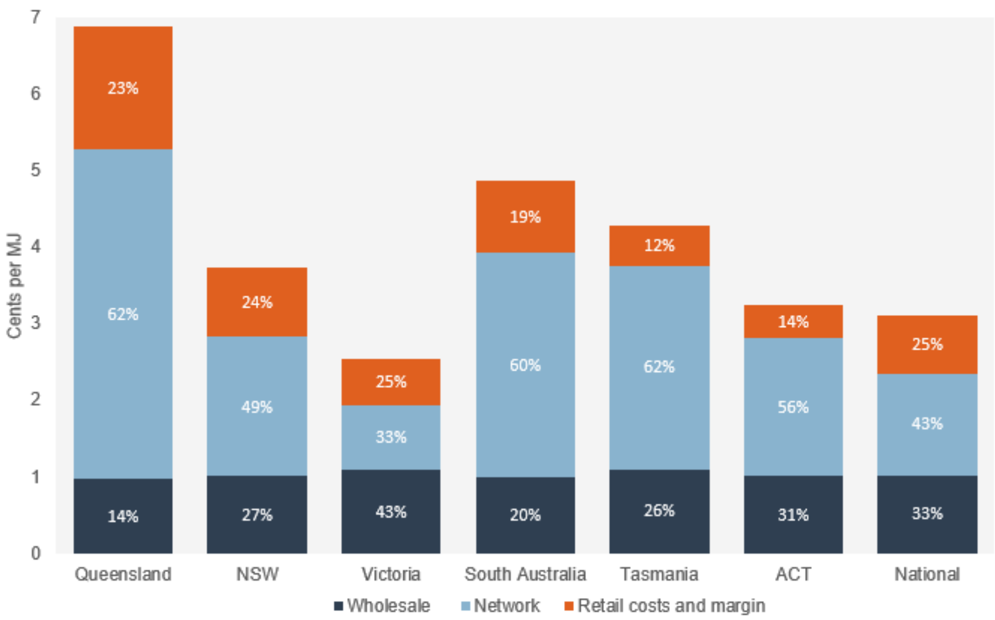
Outlook for gas

6. What do you see as the key opportunities and concerns as a gas user in Tasmania?

As mentioned above, there are a number of renewable gas developments being progressed and Tasmania is well suited to deploy these renewable gases and to build potential new energy export industries.

7. What is your view on the outlook for the pricing of gas in Tasmania?

The wholesale gas cost represents around 26% of Tasmania's residential gas bills. As such, any change in natural gas production costs will have a relatively small impact on the retail price paid by Tasmanian households.



Source: Australian Energy Regulator (2021), State of the Energy Nation – 2021, Figure 6.9.

8. Given the forecast supply shortfalls and reliance on importing gas, do you think there is any risk of supply of gas from mainland Australia?

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18 RACE2030 (2021), *One Million Homes*

Attachment 3: Responses to discussion paper questions

AEMO assesses natural gas supply risks in its annual Gas Statement of Outlook. Supply risks overseen by GSOO (source: https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo). These outlooks generally forecast a gas shortfall in the medium to long term period and this can be used as a signal by industry to bring new natural gas sources to market, through for example greater pipeline capacity with gas production regions, developing new gas fields or new gas import terminals.

Tasmania is reliant on natural gas imports from the mainland. This is not dissimilar to NSW which also imports the majority of its natural gas consumptions.

As mentioned above, renewable gas opportunities in Tasmania also create a potential energy export industry from Tasmania to the mainland and overseas.

9. If natural gas was unavailable in Tasmania, what would you do? Would you be considering moving to LPG, or to another alternative?

In the absence of natural gas, Tasmania would need to develop an alternate option to provide that energy to residential, commercial and industrial customers. Converting to LPG or electrification will require major upgrades to appliances and as mentioned above, potential repairs to properties.

Tasmania has a range of renewable gas options that it can develop. Developing its biomethane industry creates the potential to replace Tasmania's gas demand with biomethane and also creates potential export industries.

Decarbonisation pathway

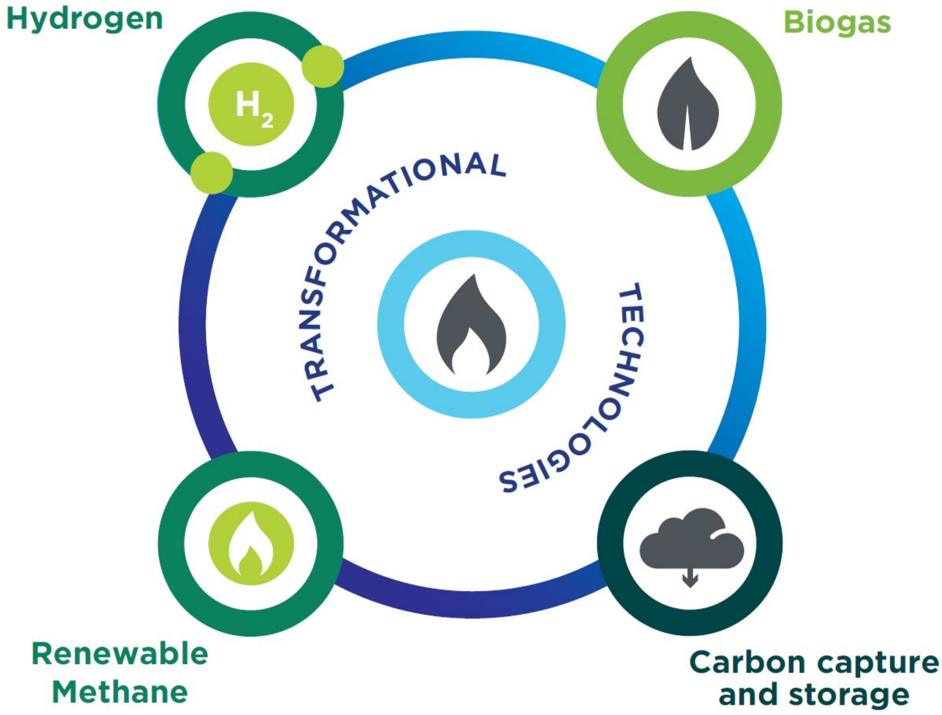
10. Should Tasmania be transitioning to a decarbonised gas network?

Australia's gas industry associations have developed Gas Vision 2050[19], the industry's response to the Paris agreement on climate change. The vision outlines how transformational technologies will be deployed to reach net-zero emissions from using gaseous fuels in Australia. The technologies include:

- Hydrogen,
- Biomethane,
- Renewable methane, and
- Carbon Capture and Storage (CCS).

[19] https://www.energynetworks.com.au/projects/gas-vision-2050/

Attachment 3: Responses to discussion paper questions



Transformational technologies (Source: Gas Vision 2050)

Decarbonising energy is essential for Tasmania to reach its emission objectives. This requires balancing the different elements of the energy trilemma– reliability (and safety), cost and environmental outcomes. For the major conversions required in the energy sector to reach net-zero emissions, the customer experience and the availability of resources should also be included.

Tasmania has natural resource advantages that would allow it to replace its natural gas consumption with biomethane and/or hydrogen produced from renewable electricity.

11. If Tasmania is to transition to a decarbonised gas network what should the transition pathway look like?

Tasmania can pursue different options for decarbonised gas, each of which may have different pathways. Generic steps may include:

a. Enable blending of up to 10% by volume of renewable gases to residential, commercial and industrial customers by 2030 (or earlier).
b. Enable 100% renewable gas supply to new residential developments before 2030.
c. De-risk a full network conversion to 100% renewable gases by 2050.

The timing is largely dependent on Tasmania's overall greenhouse gas reductions ambitions.

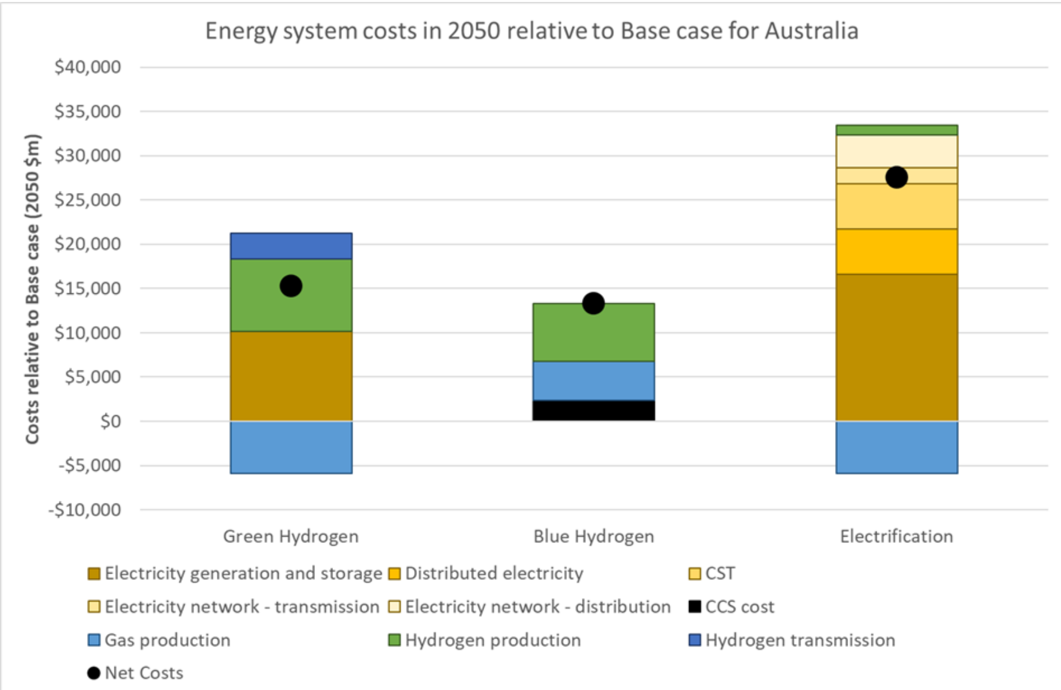
For biomethane, the pathway should start with assessing the biomethane resource potential. Due to the similarity between biomethane and natural gas, new biomethane plants can be constructed over time and gradually replace the natural gas in the network.

For hydrogen, blending into the network could demonstrate the potential of hydrogen. Full conversion to hydrogen will require a planned approach to appliance and industry modifications to enable hydrogen to replace natural gas.

12. Would a switch to a renewable fuel need to be cost-equivalent or would you be willing to pay more for a carbon free fuel?

The commodity cost, as modelled by Oakley Greenwood is only one factor that should be considered. This simple cost comparison is misleading and should be used carefully in policy design. Conversion costs and implications for networks costs should also be considered.

Modelling by Frontier Economics as part of Gas Vision 2050 showed that net zero emissions can be reached for around half the cost by using renewable gas compared to an electrification alternative. This modelling work includes all uses of gas and the changes in networks costs.



13. What risks do you see with decarbonising the Tasmanian gas network (technical, economic, social)?

There are a number of options to decarbonise the Tasmanian gas network including:

- Carbon offsets,
- Replacement with biomethane,
- Replace natural gas with renewable hydrogen, or
- Electrify the gas load (where possible).

Each one of these options has a range of technical, economic and social benefits and risks that should be assessed. All options will likely play a role to fully decarbonise the network.

Attachment 3: Responses to discussion paper questions

Blending hydrogen in gas distribution networks provides the following benefits that support a broader hydrogen economy:

- It is the lowest cost option to create and use hydrogen. At blends of 10 per cent or less, no modification will be required to end use appliances and no expensive infrastructure (e.g. for refuelling) is required.
- Leads to cost reductions for hydrogen electrolyser plants from local experience in producing these plants and better understanding the balance of plant costs.
- Improves utilisation of variable renewable generation.
- Creates take-off opportunities to provide renewable hydrogen as an industrial feedstock or to support demonstration of fuel cell vehicles.
- Increases consumer and regulatory engagement by demonstrating opportunities provided by hydrogen.
- Hydrogen will be required as an industrial feedstock in any decarbonisation scenarios, including a policy driven electrification one. Demonstrating and reducing cost of hydrogen production is no regrets.

14. If you are a commercial gas user in Tasmania that would not be able to switch to renewable alternatives, what are the key barriers?

Replacing natural gas with biomethane or renewable methane does not impact on any commercial or industrial applications.

Some industrial applications may be affected by introducing hydrogen blends or 100 % hydrogen fuels. any

Future Fuels CRC is completing research to identify if there are any issues with commercial and industrial processes in Australia, and how the burners within these processes can be modified to enable the use of hydrogen.

15. What is the role for the Tasmanian Government in a decarbonisation transition for the gas sector? What should the Government's priority measures be?

Governments can continue to support the decarbonisation of gas through the following range of complementary no-regret policies, many of which are already in place.

For renewable gases, comprising both hydrogen and renewable methane:

- Continue supporting demonstration projects.
- Encouraging market development via renewable gas targets, certification schemes and incentives.
- Enter into "reverse auctions" or "power purchase agreements" for renewable gas to encourage its take up in the market, similar to actions undertaken via the Victorian Renewable Energy Target and local council actions.

Attachment 3: Responses to discussion paper questions

- Enable gas networks to offer renewable gas opportunities in new residential developments, which will fast-track the development of 100 per cent renewable gas and ensure gas costs remain affordable for all gas users.
- Continue to decarbonise electricity generation through supporting renewable electricity generation.
- Encourage technical regulators to work collaboratively with industry in developing safety cases for demonstration projects, similar to the process adopted by the Health and Safety Executive in the UK, which is an enabling regulator that works with industry to ensure renewable gas projects can be safely deployed.

Hydrogen focussed policies.

- Support blending projects to gain technical and regulatory experience, customer acceptance and a pathway to commercial opportunities for hydrogen.
- Support the development of renewable hydrogen to support decarbonisation of industrial processes.
- Support local appliance manufacturers to provide accredited hydrogen appliances.
- Enabling opportunities for network businesses to deliver hydrogen to new residential developments.

Renewable methane focussed policies.

- Identify the resource potential of biomethane, either from local biomass resources, or from interstate resources that can be shipped using existing transmission pipelines.
- Facilitate collaboration with gas networks, technology vendors, and resource providers to develop commercially viable biomethane projects.
- Support policies to recognise the value of circular economy benefits.