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Renewable Gas Economics

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Report prepared by	Jim Snow [jsnow@oakleygreenwood.com.au] Rohan Harris [rharris@oakleygreenwood.com.au]
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1. Renewable gas economic analysis

The following analysis is an ongoing research project within Oakley Greenwood to focus on the potential costs and economics of renewable gases in the Australian market.

This research paper is one of three papers OGW plans to produce, with the other two covering:

- The key role for gas infrastructure in the storage and export of renewable energy.
- Using renewable gases to achieve a net zero emissions energy sector.

These papers are intended to assist in the consideration of technology developments that can economically reach net zero emissions and have already formed the basis of several reports OGW has been commissioned to produce and Learning Sessions sponsored by various groups.

This OGW renewable gas economics research analysis is being updated regularly as new information comes to hand but has already started to show that many of the common perceptions in the market are not reliable at this stage when it comes to the underlying economics of certain options, and that these differences are in fact critical to investment decisions in new technologies.

Work by others that we quote in this report is also starting to show that there are preconceptions that need to be very actively tested to ensure investments are made in the most promising technologies.

1.1. Renewable gases that could be used to decarbonise the natural gas grid.

There are a number of renewable gases that could be used to decarbonise the natural gas grid. These include two forms of renewable methane that is of pipeline specification (immediately useable), and hydrogen:

- Hydrogen produced from water and renewable electricity.
- Renewable methane sources:
  - Biogas, as biomethane (although biogas can play other roles); and
  - Renewable (synthetic) methane – again using water and renewable electricity, but reacted with carbon dioxide using direct air capture (DAC) technologies.

Renewable methane gases and hydrogen have very different chemical properties, which, depending on the level of hydrogen blend in a gas pipeline, might lead to significant differences in future economic costs. In particular:

- Existing type A appliances (e.g., residential appliances) are unable to take hydrogen blends above ~10% by volume.
  - This means that once this threshold is breached, those appliances need to be switched out, no matter what their age or condition, to new appliances that operate purely on hydrogen (or at very high hydrogen blends).
  - The internal house piping systems may also need to be upgraded as we are advised that hydrogen Type A appliances are likely to need higher pressure supply.
- Gas network businesses are also likely to incur additional costs as a result of moving to higher hydrogen blends. These are discussed in more detail in this analysis.

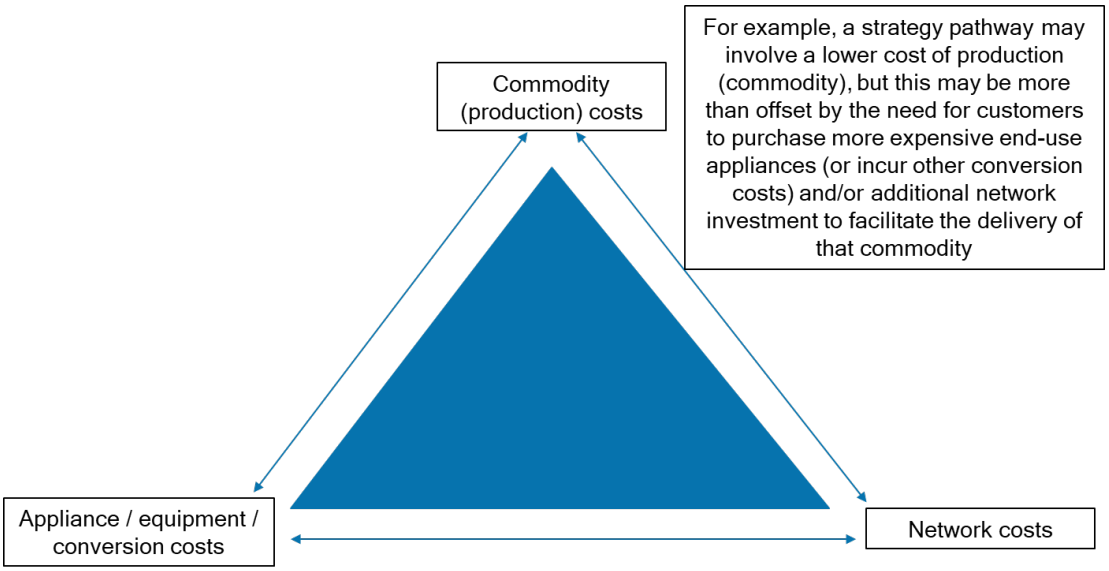
An alternative to the above that is to directly electrify existing gas loads (with renewable electricity sources). However, this will lead to additional demands being placed on electricity infrastructure, which, everything else being equal, will come at a cost.

- Much of the additional costs (in excess of the renewable electricity that will be needed) will be related to ensuring supply continuity by investing in renewable electricity storage – via several key technologies including pumped hydro, batteries and renewable gas storage.
- There is also the critical issue of investment timing if greater electrification occurs so that the development of renewable electricity generation and storage infrastructure can meet any increased demand. If this gets out of step with new demand then more greenhouse gases will be produced not less, as marginal production will once again draw on fossil fuel generation sources in the transition.
- These investment and timing issues are dealt with more specifically in the other OGW Research Analysis papers being developed.

This means that when considering gas decarbonisation there is an economic trade-off between the:

- On-going commodity (production) costs of different decarbonisation pathways.
- Upfront appliance and other switchover costs incurred by customers in switching the fuels that power their appliances, and
- The network infrastructure costs (both upfront and ongoing) associated with different decarbonisation pathways (e.g., electrification, versus hydrogen, versus renewable methane sources).

Figure 1: Trade-off between the commodity, appliance and network costs of electrification as compared to other renewable gases such as hydrogen and renewable methane



Source: OGW Research Analysis

Whichever pathway occurs, it will be important that all of the economic costs are reflected in the decisions that are made by policy makers.

The following sub-sections provide a brief overview of each of these renewable gases, and the impact that they might have on other costs along the gas supply chain.

1.1.1. Hydrogen

Hydrogen is the most abundant and common element in the universe with the molecular formula H2. At standard temperature and pressure, hydrogen is a colourless, odourless, tasteless, non-toxic, and highly combustible gas with a very high flame speed. This is in contrast to methane which is a relatively docile gas with very narrow limits of flammability and low flame speeds. Hydrogen though produces no carbon dioxide when used.

Hydrogen readily forms molecular bonds with most elements, therefore, most hydrogen on earth exists in molecular forms such as water or organic compounds. Hydrogen is primarily derived by:

- Splitting water into its base components of hydrogen and oxygen, or
- Reacting fossil fuels with steam or controlled amounts of oxygen (e.g., steam methane reforming, or SMR).

The renewable, zero-emission pathway to creating hydrogen is via electrolysis, using renewable electricity. The two main electrolysis technologies are:

- Alkaline electrolysis (AE), which involves an electrochemical cell that uses a potassium hydroxide electrolyte to form H_2 at the negative electrode and O_2 at the positive electrode.
  - AE is the most common at scale and has the lower capital costs of the two currently.
- Polymer electrolyte membrane (PEM), whereby water is catalytically split into protons which permeate through a membrane from the anode to the cathode to bond with neutral hydrogen atoms and create hydrogen gas.
  - PEM produces hydrogen at greater pressures and purity than AE, and also requires high quality water to reach its higher efficiency (so water treatment is critical).
  - PEM is also more modular and scalable and can work to high levels of overload for short periods – more tolerant of rapid switching (on and off) – more dispatchable, which may be an advantage in the NEM as renewable generation production increases (due to its natural variability).

Whilst the primary technologies used to undertake this process are mature (e.g., electrolysis) and have not changed significantly in recent times[1], the costs of, and emissions stemming from, the electricity used to power the process have changed significantly. Renewable hydrogen can be produced at very high purity (>99.99%) and can be used in many applications, for example fuel cells in vehicles. The energy conversion efficiency is about 80% as this is an endothermic reaction (H_2 energy out equals about 80% of the renewable energy in) but utilisation of the plant can be very low, and it is a net consumer of water (which must be clean and pumped).

SMR is also a mature technology, however, it needs to be combined with carbon capture and storage (CCS)[2] if it is to provide a source of low emissions hydrogen[3]. Even then, it is still not technically "renewable", but low net emission technology.

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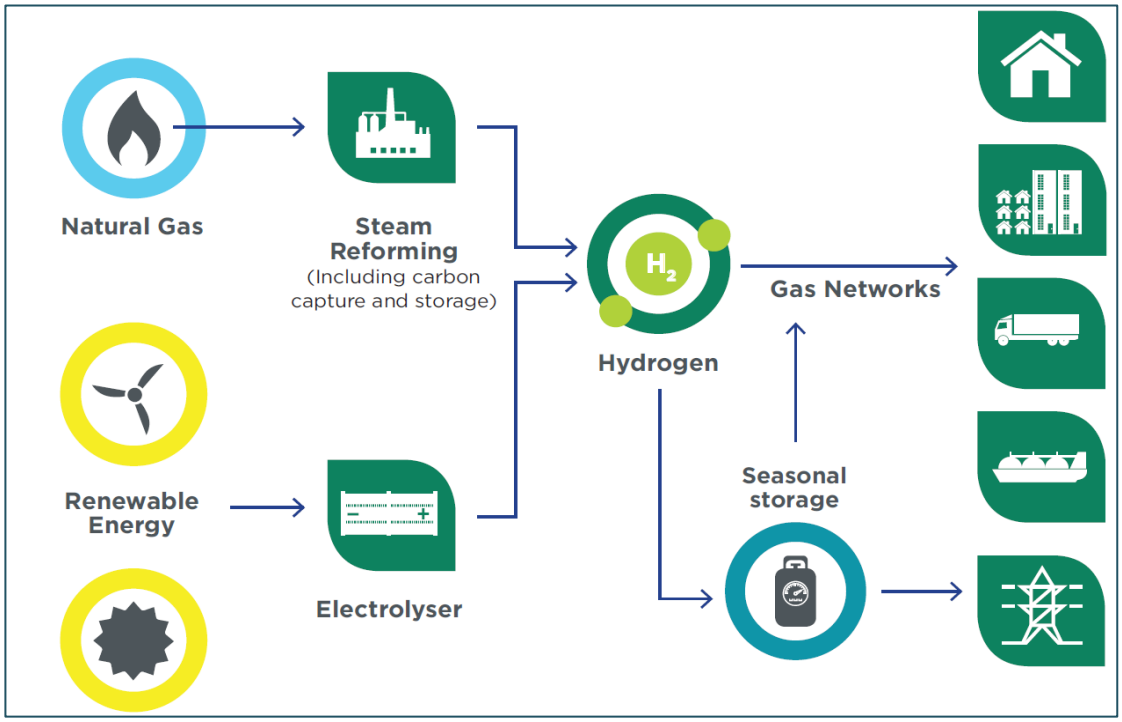
1 Although there is significant R&D work being undertaken in this regard in Europe and other places – the potential has been recognised internationally.

2 This is often referred to as "blue" hydrogen, as opposed to "brown" hydrogen, which generally refers to hydrogen produced from brown coal, or "grey" hydrogen, which generally refers to hydrogen produced from a fossil fuel without carbon capture and storage.

3 There are inevitably small amounts of carbon emissions even when paired with CCS technology, hence it is low-emissions, not zero emissions.

Figure 2: Hydrogen production pathways



Source: Energy Networks Australia (ENA), *Gas Vision 2050*, page 4

Whilst there are only a relatively small number of examples[4] of hydrogen being blended into an existing natural gas network at moderate levels across the world, an increasing number of natural gas businesses are actively investigating the option of blending hydrogen into their distribution networks. Existing networks and appliances are designed to operate effectively with moderate amounts of hydrogen, however, where the hydrogen content increases beyond a certain level, appliance modifications are required as hydrogen and natural gas behave differently when burnt. Modern gas distribution networks (excluding high pressure transmission systems), however, should be able to transport large proportions of hydrogen safely[5] with suitable investments.

1.1.2. Biogas and biomethane

Biogas is a mixture of CH_4 and CO_2. Biogas is obtained from biomass, which is a plant or animal material that is used for energy production. It is produced from a biological process, for example:

- Via landfill, which is a site for the disposal of waste materials by burial; or
- Anaerobic digestion, which consists of a series of biological processes that are generally used in the sewerage treatment process, dairy waste, or treatment of food waste.

4 Examples include in France, https://www.engie.com/en/businesses/gas/hydrogen/power-to-gas/the-grhyd-demonstration-project; Adelaide, https://blendedgas.agn.com.au/; UK, https://hydeploy.co.uk/hydrogen/

5 The gas industry is familiar with ensuring the safety of gas appliances and has, in the last 50 years, carried out a major conversion program from Towns Gas, which consisted of a significant proportion of hydrogen, to natural gas.

In many cases, biogas production is secondary to a business' main production process (e.g., landfill, sewerage treatment, food production), and its potential utilisation is generally as a feedstock for the production of on-site renewable electricity (with potential to export to the grid, if grid-connected). That said, centralised facilities can be developed, increasing the receiving facility's scale, although this is likely to be partially offset by additional collection and transportation costs.

The quantity of biogas and hence biomethane produced per tonne of organic matter varies with the quality of the matter collected and type of organic matter e.g., from 75 up to 300 m^3 of methane per tonne of organic compounds.

As biogas also contains carbon dioxide and water vapour, for it to be utilised as a direct substitute for natural gas (e.g., via distribution by natural gas networks), it needs to be 'cleaned' in order to form biomethane. There are technologies readily available to do this, however, they add to the cost of production as compared to using the 'uncleaned' biogas to generate electricity (the economics of the addition of a "cleaning" process also depends on the proximity of the resources to the existing network).

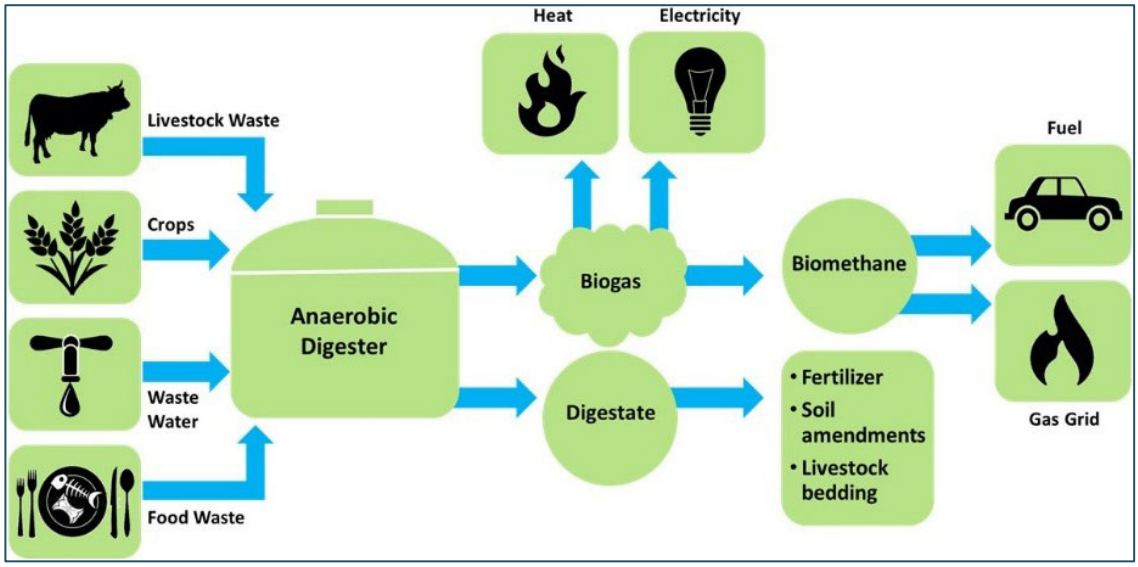
The consumption of biomethane emits net zero CO_2e. This means that it does not add directly to the overall carbon dioxide stock in the atmosphere as the biological waste is a net remover of carbon dioxide from the environment.

The carbon dioxide produced in the digestion process is also often termed green carbon dioxide and can be combined with hydrogen to produce more biomethane from the same source, doubling effective output of biomethane.

- This is achieved by using methanation technology, which, despite being off the shelf, has not been well deployed at scale even though it can potentially double production from bioenergy sources.

An example of the process that converts biogas to renewable electricity, and biogas to biomethane, is outlined in the figure below.

Figure 3: Production of biogas and biomethane



Source: https://www.eesi.org/papers/view/fact-sheet-biogasconverting-waste-to-energy

The Australian Bioenergy Roadmap, Enea and Deloitte for ARENA, 2021 has also just been released (November 2021) and it is the first major study to explore the potential for bioenergy to play a key part in providing renewable energy in the Australian economy considering the drive to net zero emissions.

- This report points to a total theoretical resource in the NEM states of some 2,150 PJ/year and has assumed (based on extensive consultation and research) that 45% of this could be accessed, 968 PJ/year.
- Under a "*Targeted Deployment*" scenario, 151 PJ is attributed in the report to *Pipeline Gas*, however 279 PJ is also directly attributed to *Industrial Heat* (which largely comes from gas now) and points to other uses of the gas such as for power generation (again potential displacing natural gas).
  - In comparison, the east coast gas market is some 570 PJ/year (2020),
  - This highlights bioenergy's potential significance as a resource opportunity, dispelling previous preconceptions by some policymakers and analysts that this is a small resource that can only ever contribute at the margin to the decarbonisation of natural gas usage.
  - Overall, the report assessed that some 559 PJ/year could be generated from bioenergy in total

    "reflecting greater utilisation of existing resources and potential for new sustainable resources."
  - Clearly the bioenergy resource is now far more significant than was perceived in the market and could for example play a major role in decarbonising natural gas networks.
  - The forecast costs of this resource are also very competitive with natural gas making this resource even more prospective.
- OGW note this work did not add in the potential doubling effects of being able to react the green carbon dioxide produced when cleaning the biogas to achieve pipeline specifications with a source of hydrogen, as this was not its focus.
  - It is possible for example that all the natural gas currently used on the east coast could be displaced by biomethane - through direct production and methanation of the bioproduct carbon dioxide.

1.1.3. Renewable methane

Renewable methane can be produced by reacting renewable hydrogen (H_2) with carbon dioxide (CO_2) in a 'methanation' process.

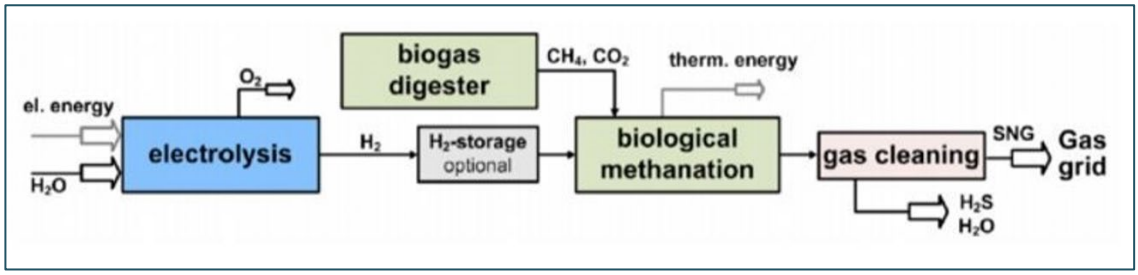
- As such, it currently is achieved using a two-step process: the production of hydrogen, and then the methanation process.
- Early exploration of the development of a one-step reactor are starting to be examined, where water, electricity and carbon dioxide are injected into one high temperature and pressure reactor.
  - This is not only technically viable but potentially able to provide a high efficiency process of energy conversion (similar to hydrogen production) as the methanation reaction is exothermic (returns energy to the reactor), and
  - It also provides some 80% plus of the water back for reuse in the process.

Whilst the current two-step process marginally adds to the cost, relative to the production of hydrogen, it creates the same molecule as biomethane (and methane), which has some clear economic advantages over hydrogen.

The carbon dioxide used in this process could come from a natural source, such as a biogas facility (Figure 4), or it could be extracted directly from the atmosphere and then combined with hydrogen to produce methane[6].

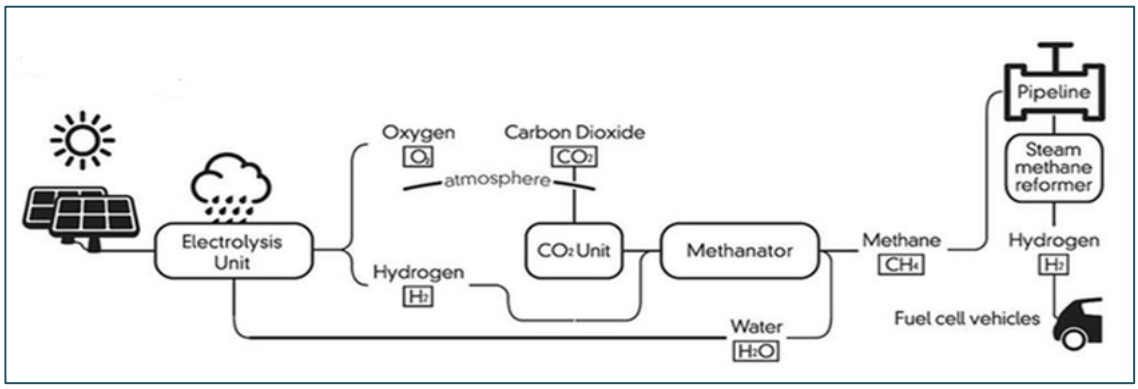
The carbon extracted balances the carbon emitted when the methane is used, therefore making the methane both renewable and carbon neutral (net zero).

Figure 4: Production of renewable methane via biogas



Source: www.neocarbonenergy.fi/wp-content/uploads/2016/02/06_Tynjala.pdf

Figure 5: Production of renewable methane via extraction of carbon dioxide from the atmosphere



Source: https://www.southerngreengas.com.au/about.html

This process produces a gas that is fully compatible with existing appliances, all gas networks, gas storage facilities and LNG facilities, and hence no additional downstream infrastructure costs or investments of any relevance are incurred. Any marginal additional costs are incurred in the methanation process.

- This means it competes with more expensive processes such as ammonia production, storage, shipment and end use or direct hydrogen liquification, storage, transportation and regassification.

6 A low emission (not renewable as such) version of methane production may be possible using the carbon dioxide from sequestered CCS or carbon dioxide emissions that are already part of the National Greenhouse Gas Inventory.

- The current infrastructure is already a sunk cost if the renewable gas is a form of renewable methane.

1.2. Current economics of renewable gases

The following sections provide a high-level estimate of the potential costs of the different alternatives, both now and in the long-term. Clearly, any long-term forecast is subject to a range of uncertainties, and hence, these cost estimates should be considered in that light. As new reliable information comes to hand, this work will be updated.

1.2.1. Hydrogen via electrolysis

Despite their market availability and maturity, Proton Exchange Membrane (PEM) and Alkaline Electrolysers (AE) – the two most common and mature electrolyser technologies - are still relatively expensive from a capital cost perspective when compared to many sources of renewable electricity.

Table 1: Current estimates of the capital costs of different types of electrolysers ($/kW)

Source	PEM ($/kW)	Alkaline ($/kW)	Integrated Solar and (2 hr) Battery - ($/kW)	Large Scale Solar PV ($/kW)
CSIRO ($AUD)	$3500	$2500	$2139	$1408
IRENA ($USD)	$700-$1400	$500-$1000	NA	NA

Source: CSIRO, "Genos 2020-21 - Consultation draft"; December 2020, page 49 and page 63; IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal, International Renewable Energy Agency, Abu Dhabi

Notwithstanding this, numerous notable agencies are forecasting electrolyser capital costs to decline significantly in the medium to long-term, driven by the efforts of countries to decarbonise their economies. This underlying increase in demand for electrolysers is forecast to be a catalyst for, amongst other things:

- A significant increase in the scale of production ('giga-factories'), inevitably leading to economies of scale and lower prices in the long-term.
- Industrial scale engineering, procurement and construction (EPC) being adopted for electrolysers, based on mature and scalable technologies, and
- Competitive long-term debt financing as a result of de-risking offtake agreements and in turn cash flows.

Recent, published, forecasts of capital costs from the CSIRO and IRENA are reproduced in the figures below.

Figure 6: Capital cost forecasts (2050) by CSIRO

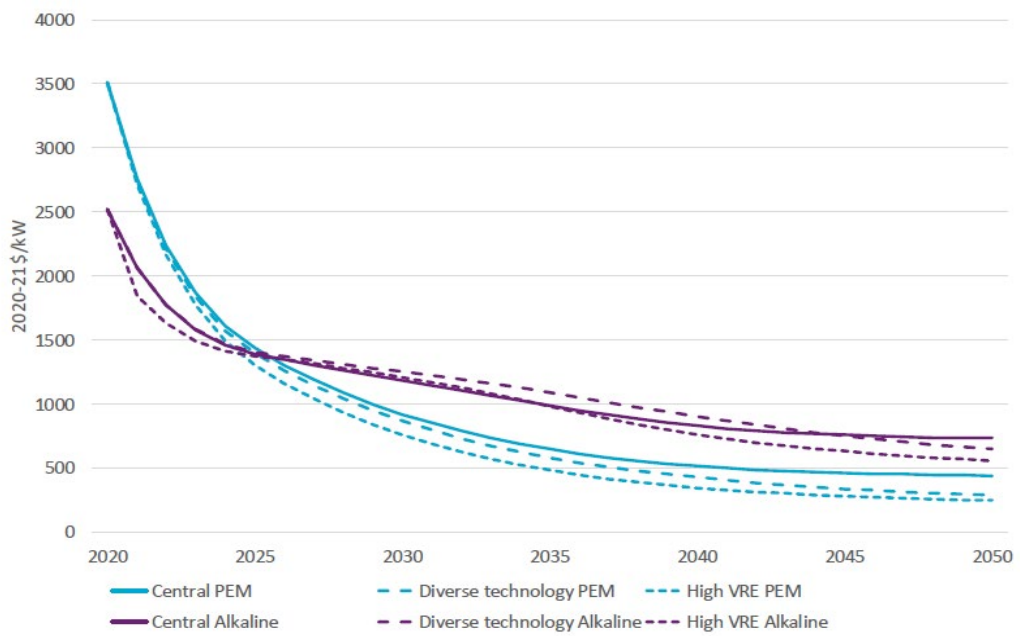


Figure 4-18 Projected technology capital costs for alkaline and PEM electrolysers by scenario

Source: CSIRO, *genos 2020-21 - Consultation draft*, December 2020, page 49

Figure 7: Capital cost forecasts (2050) by IRENA

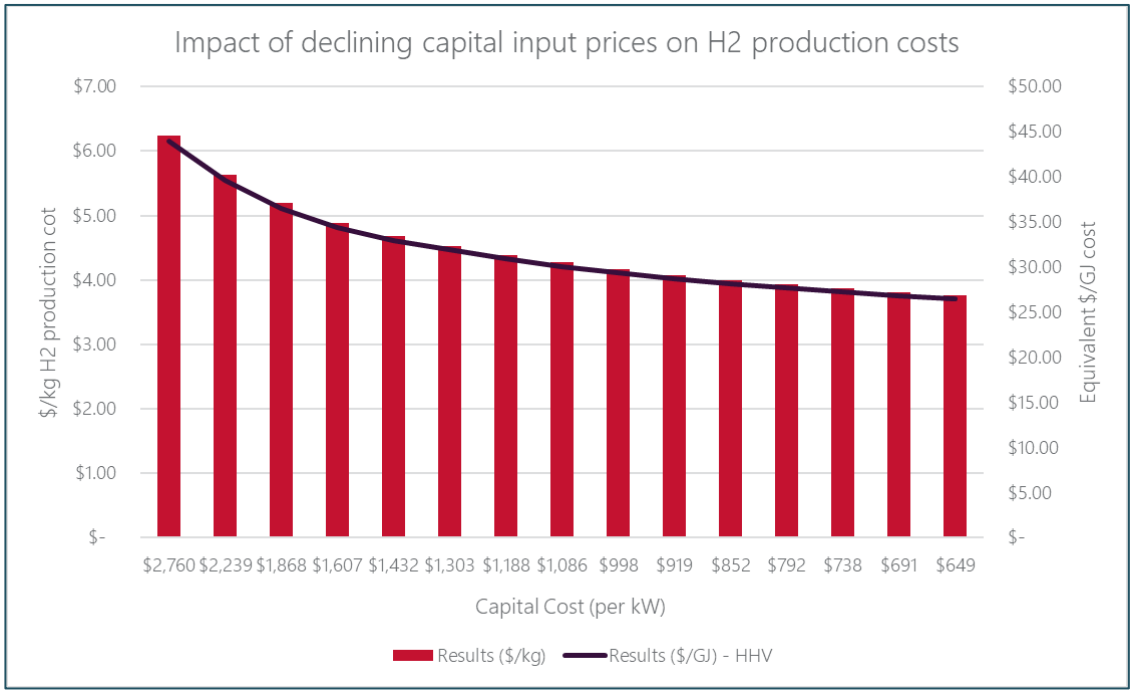
	2020				2050			
	Alkaline	PEM	AEM	SOEC	Alkaline	PEM	AEM	SOEC
Cell pressure [bara]	< 30	< 70	< 35	< 10	> 70	> 70	> 70	> 20
Efficiency (system) [kWh/KgH_2]	50-78	50-83	57-69	45-55	< 45	< 45	< 45	< 40
Lifetime [thousand hours]	60	50-80	> 5	< 20	100	100-120	100	80
Capital costs estimate for large stacks (stack-only, > 1 MW) [USD/kW_{el}]	270	400	-	> 2 000	< 100	< 100	< 100	< 200
Capital cost range estimate for the entire system, >10 MW [USD/kW_{el}]	500-1000	700-1400	-	-	< 200	< 200	< 200	< 300

Note: PEM = Polymer Electrolyte Membrane (commercial technology); AEM = Anion Exchange Membrane (lab-scale today); SOEC = Solid Oxide Electrolysers (lab-scale today).

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

The following figure highlights the impact that declining capital costs might have on the cost of producing green hydrogen.

Figure 8: Impact of declining capital costs on H2 production costs - 70% CF/electricity cost ($30/MWh)



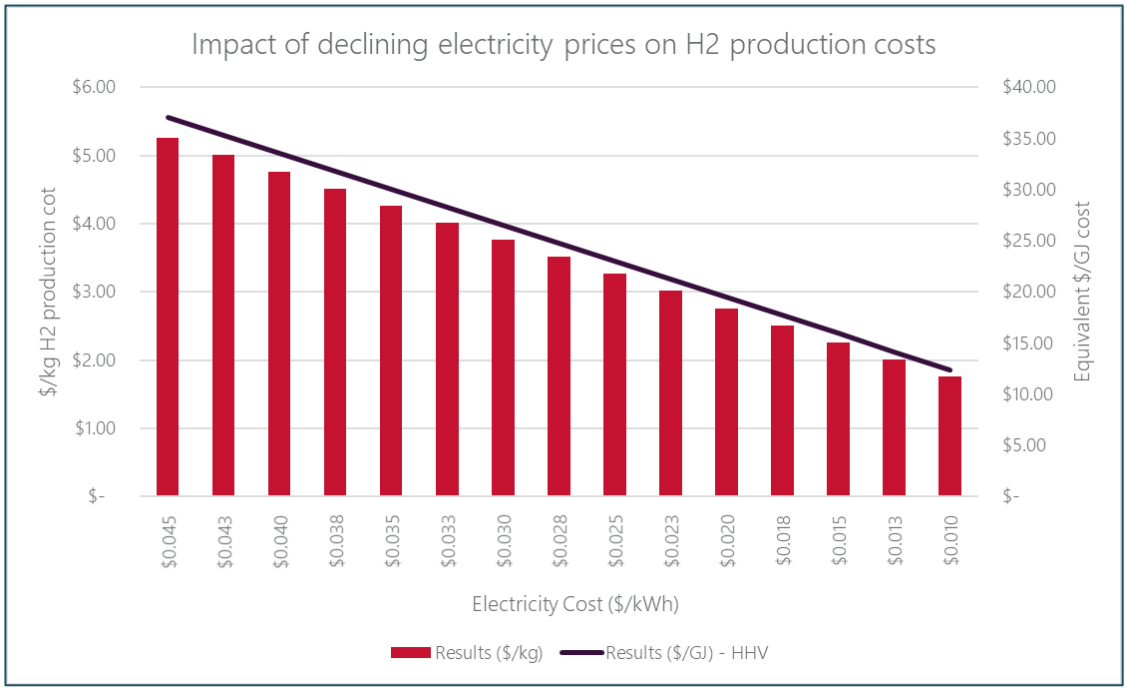
Assumptions include: a) Electrolyser efficiency of 50kWh/kg; and b) Lifespan of 120,000 hours, consistent with upper end of IRENA; c) capacity factor of 50%[7]; d) electricity price of $30/MWh; e) capital cost declines consistent with CSIRO forecasts; e) WACC = 5%; and f) GJ per kg = 0.142

Assuming a feedstock (electricity) price of $30/MWh and a capacity factor of 50%, declines in capital costs from $2000/kW down to ~$650/kW between now and 2035, move the cost of producing hydrogen from ~$6.25/kg, equivalent to around $43/GJ (HHV), down to $3.76/kg, or $26.50/GJ.

This indicates that whilst forecast reductions in capital costs are important, the cost of producing hydrogen will still be highly dependent on the cost of the (renewable) electricity input. The impact that electricity prices have on the cost of production in the medium term (~2035) is highlighted in the following figures.

7 In practice, a hydrogen production facility would optimise its capacity factor, taking into account, amongst other things, the dispersion of wholesale electricity costs.

Figure 9: Impact of declining electricity prices on H2 production costs in medium term (2035) - 50% CF



Assumptions include: a) Electrolyser efficiency of 50kWh/kg; and b) Lifespan of 120,000 hours, consistent with upper end of IRENA; c) capacity factor of 50%; d) capital cost / kW of $650 consistent with CSIRO forecasts for ~2035; e) WACC = 5%; and f) GJ per kg = 0.142

If a feedstock (electricity) price of $45/MWh and a capacity factor of 50%, along with forecast medium term capital costs of $650/kW is assumed, the cost of producing hydrogen is still quite prohibitive at $5.26/kg, equivalent to around $37/GJ. If input prices decline to $10/MWh, in conjunction with a 50% capacity factor, the cost of producing hydrogen reduces to very competitive levels at $1.76/kg, equivalent to around $12.40/GJ.

In addition to the cost analysis presented above, the production of hydrogen also has a number of other attractive properties, in that it is:

- Scalable, which implicitly provides option value, and can be contrasted to biogas/biomethane which requires organic waste or new material as a feedstock.
- Flexible with regards to its location, particularly if it is grid-connected, and
- Able to be used in a manner that supports the broader electricity system, for example, it can be used to boost energy security, which is particularly important in the future with even more variable renewable energy (VRE), as well as providing other ancillary services such as FCAS, voltage support etc.

Notwithstanding the above, there are significant implications of using hydrogen on electricity infrastructure. Using Victoria as an example, the following table provides an estimate of the amount (GW) of solar and wind generation capacity that would be required if Victoria, the largest gas consuming state in Australia, sought to replace 10% (by volume, H_2 equivalent) and 100% (by volume) of their forecast gas demands in 2035.

Table 2: Renewable energy capacity requirements (MW) - Victoria

Target	Solar (MW)	Wind (MW)
10% by volume	2,900	2,421
100% by energy	28,996	24,163

Notes: The difference reflects their relative average capacity factors: estimated at 36% for wind and 30% for solar.

In addition to the above, the incompatibility of hydrogen with existing infrastructure beyond around 10% by volume blends would necessitate a large-scale retrofit of both end-use appliances/equipment and augmentation of existing distribution networks, likely new transmission networks dedicated for hydrogen and potentially other midstream parts of the gas value chain such as storage. For example, the following costs associated with a 100% hydrogen supply are currently considered to be unavoidable:

- Customer equipment:
  - Residential Customers - replacement of all meters, testing and possible replacement of internal piping and replacement of Type A appliances.
  - Commercial Customers - replacement of all meters, testing and possible replacement of internal piping and modification or replacement of Type B appliances.
  - Industrial/Manufacturing - replacement of all meters, testing and possible replacement of internal piping and modification or replacement of kiln/furnaces/ heating/process systems.
- Distribution networks:
  - Networks on a simple turn in of 100% hydrogen would be significantly de-rated (as H_2 has one third of the energy density of natural gas by volume). This will need to be overcome by increasing pressures in sections of the networks where that is possible, and augmentation by looping in other parts of the network to ensure the same amount of energy can be transported as is currently the case of natural gas.
  - The assessment of various pipeline systems and how they react to 100% hydrogen also needs to be understood e.g., mid-pressure steel, cast iron or galvanised iron where it still exists, nylon, poly pipes, old copper, stainless steel, etc.
  - The networks would also have to assess all the ancillary equipment suitability as well such as valving, network control systems and related piping, customer regulators and district pressure regulating and let down systems, safety systems, etc.[8]
  - Operational procedures would have to be redeveloped along with safety cases, etc. as hydrogen is a far more flammable gas that natural gas.

8 Considerable work on related network component and piping systems is being undertaken in the UK led by Northern Gas Networks (H21) with Government sponsorship over the next two to five years. It must be stressed however that this will most likely not be sufficient to simply apply to Australian gas systems and similar testing work would have to be carried out in Australia.

- Transmission networks:
  - There is significant uncertainty – even for the owners of the assets - as to whether the existing transmission systems in key markets on the east coast are able to accommodate hydrogen, or even a small hydrogen blend.
  - Again, general studies into the ability for transmission pipelines to accommodate certain hydrogen blends cannot necessarily be translated to all transmission networks across Australia. Each network, and different parts within each network, are constructed out of different materials, operate under different conditions/pressures, and are of different ages, all of which are likely to be relevant in determining whether or not they can accept hydrogen (or even a small hydrogen blend).
- Gas storage facilities:
  - Similar to transmission networks, there is significant uncertainty – even for existing owners of key storage assets - as to whether their gas storage facilities would be able to accommodate hydrogen, or even a hydrogen blend.

1.2.2. Renewable methane

Renewable methane (the same chemical composition as methane) can be produced by reacting renewable hydrogen (H_2) with carbon dioxide (CO_2) in a 'methanation' process.

The carbon dioxide used in this process could come from a natural source, such as a biogas facility, or it could be extracted directly from the atmosphere and then combined with hydrogen to produce methane.

The appealing factor with methanation is that the chemistry is very well known (over 100 years) and has been undertaken in refineries for many years based on fossil fuel refining and conversion.

However, process integration with renewable power and air borne CO_2 via direct air capture (DAC) is more embryonic – and is an engineering challenge, not one of basic chemistry.

- That said, integration in a one-step reactor design is, on face value, also very appealing, given that the production of hydrogen requires continuous energy input (endothermic) whereas the methanation process produces heat once it commences (exothermic).
  - This makes them complementary processes (thermally) and a strong candidate for process integration to achieve high conversion efficiencies within one reactor or process plant.
  - The electrolysis reaction also requires less electricity input if heat is available and high pressures may also assist in that regard (depending on how this is developed), catalyst selections may also assist, and
  - The methanation reaction also returns a lot of the initial water used.
- European technology prototype trails (TRL 4-5) have shown that it is technically feasible to convert 75% to 80% of the renewable electricity to methane in such reactors, and the target of >85% efficiency is thought to be achievable.
  - If this is the case, then this technology development would also represent a key priority.

Notwithstanding this potential in technology development for methanation, for the purposes of our analysis, we have simply estimated the cost of adding a methanation plant along with direct air capture (DAC) to the hydrogen production costs that we outlined in the section above.

- This linear approach does still though return quite a lot of heat and water which if used correctly can materially reduce the costs of this overall process.

To inform this process, MAN, a large multinational company based in Germany that produces methanation reactors, invests in electrolyser technologies, produces diesel engines and turbomachinery for marine and stationary applications such as marine propulsion systems, power plant applications and turbochargers, provided us with a high-level indicative estimate of the capital cost associated with a 5PJ (13,700GJ/day) methanation and DAC plant. We calculated a levelized capital cost based on the plant cost, production per annum (5PJ), a WACC of 5% and life of 20 years.

- Again, it must be stressed that this modelling is very preliminary and was undertaken to assess the relative magnitude of the marginal costs likely from this linear approach to methanation (as the technology is readily available) and it has shown that these marginal costs in this first cut analysis appear to be quite low.
- This has its own economic and investor implications when considering using hydrogen directly or undertaking methanation of the hydrogen to produce renewable methane for direct displacement of natural gas in all the existing infrastructure and LNG plants for example.

In addition to the capital cost, we have added an estimate of the levelized cost of operating the plant, which we have assumed is predominately driven by the costs of electricity. To inform this estimate, we applied a wholesale electricity cost assumption of $40/MWh[9], multiplied by an assumed electricity consumption of 400kWh[10] per ton of CO_2 for the DAC plant plus an additional allowance for electricity used in other parts of the process.

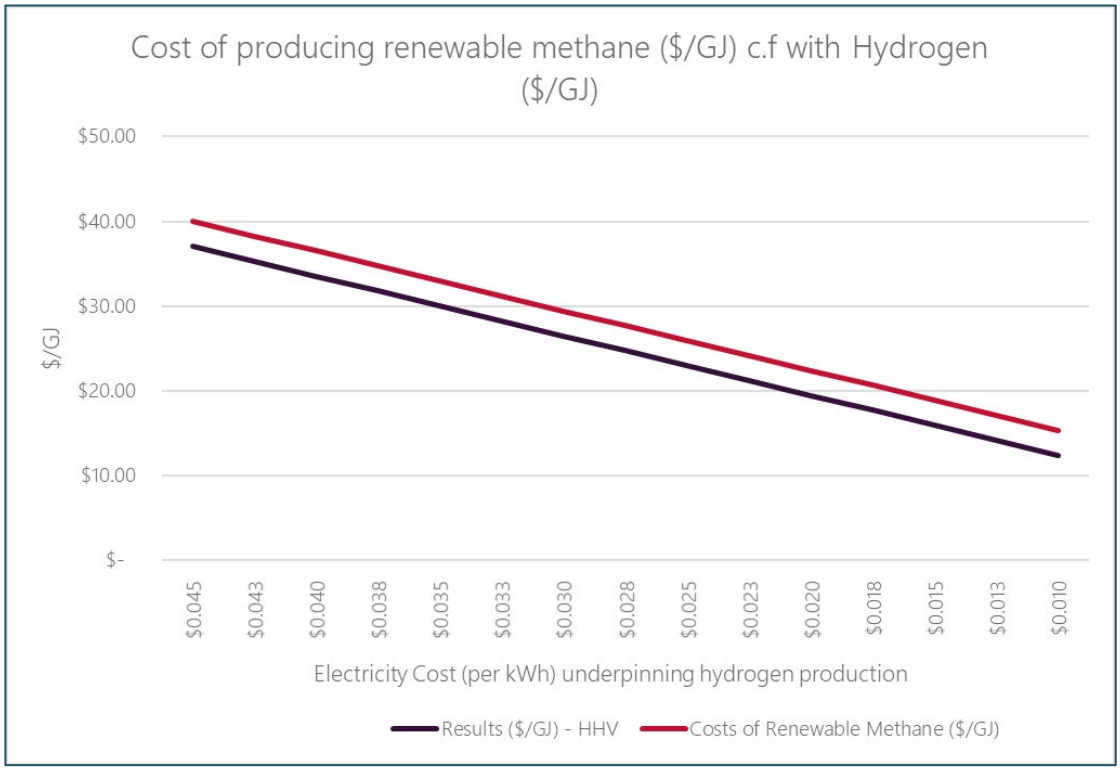
- Further research is being undertaken of forecasts for this energy use as it does vary in the preliminary reviews undertaken down to 170kWh for example, and several reports are coming available on overall costs.
- It is also apparent that some of the heat from a single stage reactor could be deployed to assist DAC technologies, and there maybe water production benefits as well – again pointing to even greater process integration potential.

The following figure summarises the modelled costs of renewable methane, assuming no reduction in the capital cost of the methanation plant, and assuming that this cost gets added to the different hydrogen production costs aligned to the analysis presented in the previous section (assuming a $650/kW capital cost for an electrolyser).

9 Note that we have assumed that the methanation plant operates at ~100% capacity factor.

10 Christoph Butler, Louise Charles and Jan Wurzbach, '*The Role of Direct Air Capture in Mitigation of Anthropogenic Greenhouse Gas Emissions*'.

Figure 10: Cost of producing renewable methane – no reduction in methanation capital costs

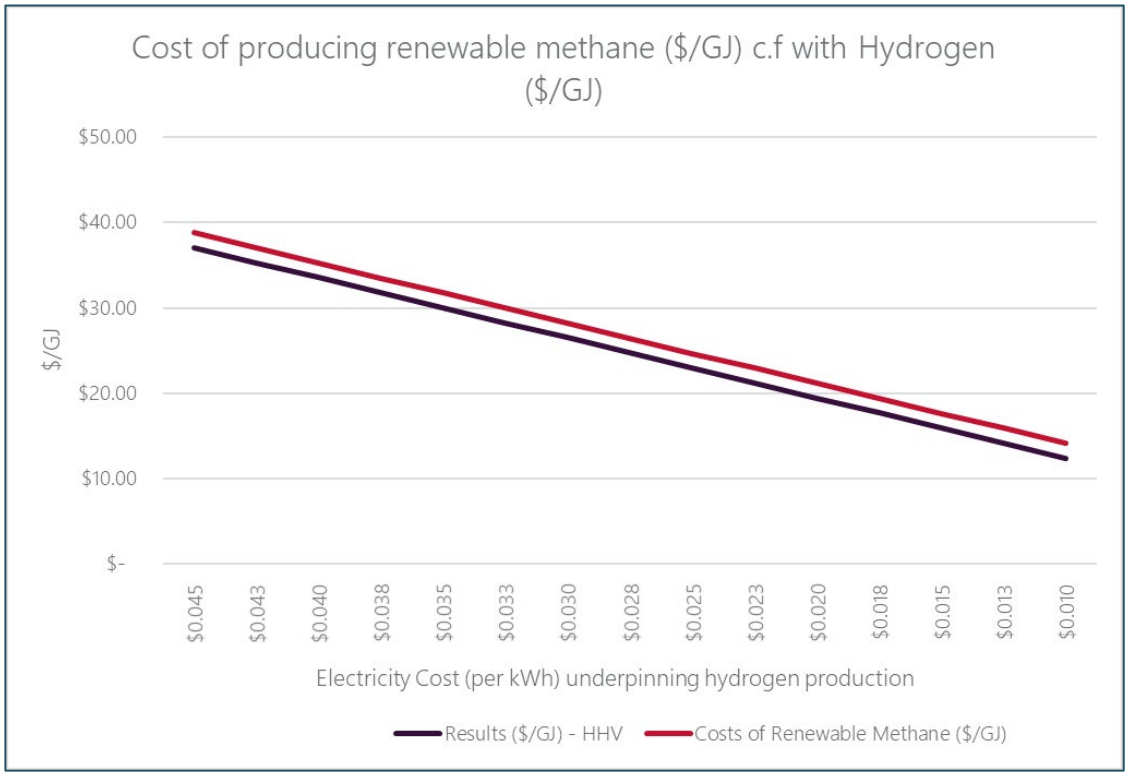


Source: OGW analysis

Clearly the marginal costs in this modelling of the methanation process (over the costs of the electrolysis process) came out very low, recognising that the methanation process is actually a well-developed technology in of itself.

The following figures highlights the results if we assumed a similar trajectory in the capital costs of methanation as is being forecast by the likes of the CSIRO for electrolysers – that is applying the cost trajectories for the hydrogen production component and some to the methanation process.

Figure 11: Cost of producing renewable methane – assuming a reduction in capital costs



Source: OGW analysis

As compared to hydrogen, renewable methane has a number of other very attractive properties including that it:

- Allows Australia to retain its existing gas transmission, distribution and storage infrastructure, with no need for any other change.
- Avoids the need for customers to change out appliances to cater for either:
  - A new gaseous fuel (hydrogen); and / or
  - Electrification of some of their existing loads.
- Depending on the ability and cost to scale up methanation facilities, it represents one of the only true means of decarbonising many hard-to-abate sectors like peaking electricity and high temperature process heat, and
- Potentially facilitates the creation of a new export market – renewable methane as renewable LNG, using all the existing LNG production assets.

The key here is that in the gas sector, the technology investment is purely in the methanation reactor and process design and not in the gas infrastructure or customer end use appliances and processes.

- Also, now more critical to our analysis is the developments in the forecast size of the biomethane resource, and by inference the size of the "waste" stream of green carbon dioxide.
- The marginal costs of production already shows major promise even with DAC, and therefore will be presumably a lot better with carbon dioxide derives from the clean-up of biogas to biomethane.

- This will be an area of further analysis for future updating of this report.

The electricity system will still need to be able to supply renewable electricity but with methanation technology development this may be a lower requirement than for pure hydrogen production, and with the massive level of gas storage available to renewable methane the utilisation of production plants such as renewable energy generation could be very high (limited by sun and wind only).

Renewable methane also does not inhibit the use of biomethane or up to 10% by volume of hydrogen.

1.2.3. Biomethane

The cost of producing biomethane via anaerobic digestion includes three distinct elements: biogas production costs, biogas cleaning and upgrading costs, and distribution costs.

IRENA has previously (2017) indicated that the typical price of[11]:

> *producing biogas ranges between USD 0.22 and USD 0.39 per cubic meter of methane for manure-based biogas production, and USD 0.11 to USD 0.50 per cubic meter of methane for industrial waste-based biogas production.*

It also stated that it anticipated that cost reductions in the range of 30 to 40 per cent appear to be realistic, although it is not clear over what time horizon these cost reductions are projected or why exactly they considered these cost reductions to be reasonable.

- The major touch points though, as we understand it, are in ensuring or incentivising the economic gathering of organic matter and ensuring it is in as homogeneous streams as possible; and that there is scope in the development of the gas cleaning technologies for marginal cost reductions.

The 'cleaning' or scrubbing process, which involves cleaning the gas of particles, water and hydrogen sulphide to reduce the risk of corrosion, and then upgrading the gas by removing carbon dioxide to raise the energy content and create a gas with constant quality consisting of about 98% methane, adds to this cost. IRENA indicates that the cost of this upgrading typically only accounts for 5-10% of production costs[12].

If we take the top end of the range quoted by IRENA, the cost of producing biomethane is in the order of US$0.55 per cubic meter, which equates to in broad terms around A$20/GJ.

Separately, confidential information we have been provided by proponents operating in Australia, indicated large scale projects cost $15 to $23 per GJ, excluding any value for biomethane's green attributes. This broadly aligns with prices ascribed to biomethane projects in Germany, although higher costs have been ascribed to projects in France in Figure 12.

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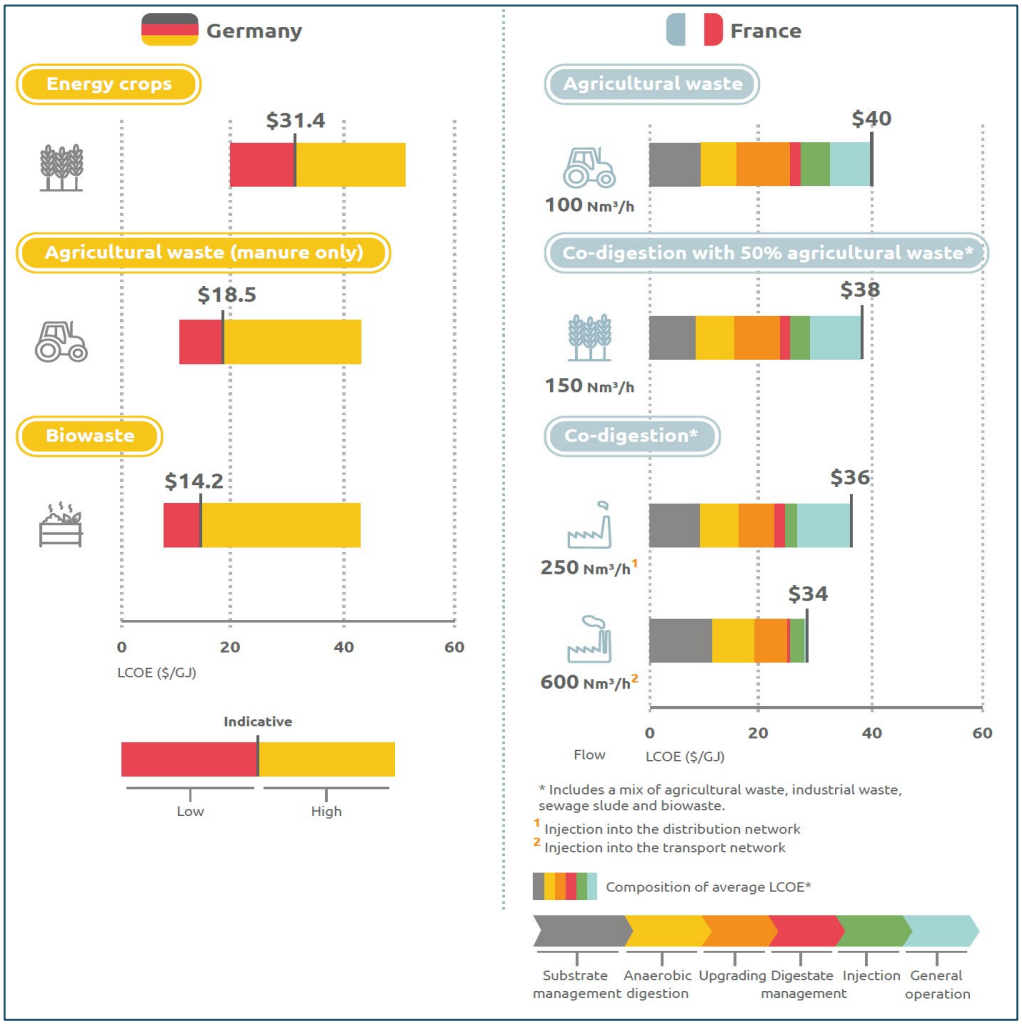
11 https://irena.org/newsroom/articles/2017/Mar/Biogas-Cost-Reductions-to-Boost-Sustainable-Transport

12 https://www.irena.org/costs/Transportation/Biomethane

Figure 12: Cost of producing and injecting biomethane into the German and French Grids in US$



Source: ENEA, *Biogas Opportunities for Australia*, page 38

Whilst it is clear that biogas production costs are situational dependent, for example what feedstock is relied upon, a price of around $20/GJ appears to be fairly commonly reported, aligning to the reported information out of Germany, the information we have been provided by a proponent in Australia, and broadly consistent with the costs reported by IRENA for biogas (after making an allowance for the cost of upgrading biogas to biomethane).

Applying IRENA's 40% cost reduction[13] to this produces a long-term figure in the order of $12/GJ, or ~$43/MWh (based on a GJ to MWh conversion of 0.277778).

- It is also noted that the recently released **Australia's Bioenergy Roadmap, Enea and Deloitte for ARENA, November 2021** report modelled the pricing for biomethane at $12.20/GJ in 2021 and $9.80/GJ in 2030.

13 Noting again, for the avoidance of doubt, that IRENA does not specify over what time frame is believes this cost reduction is achievable.

- This is lower than other sources we have been able to access and seems to indicate that the pricing curves have advanced toward the IRENA forecast very quickly when studied and modelled in such detail, and importantly within the Australian context.
  - This new price point is indeed highly significant and OGW will seek to discuss the underlying assumptions with its authors as part of updating this report.